DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF EMISSIONS FROM OIL AND GAS EMISSIONS OPERATIONS

5 CCR 1001-9

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

Outline of Regulation

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

PART A Applicability and General Provisions

I. Applicability

I.A.

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

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

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

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

I.A.2. REPEALED

I.A.3. REPEALED

II. General Provisions

II.A. Definitions

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

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

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

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

II.A.3. "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.4. "Volatile Organic Compound (VOC)" means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions, except those listed in Section II.B. as having negligible photochemical reactivity. VOC may be measured by a reference method, an equivalent method, an alternative method, or by procedures specified under 40 CFR Part 60 (July 1, 2022). A reference method, an equivalent method, or an alternative method, however, may also measure nonreactive organic compounds. In such cases, an owner or operator may exclude the compounds listed in Section II.B. when determining compliance with a standard if the amount of such compounds is accurately quantified, and such exclusion is approved by the Division. As a precondition to excluding such compounds as VOC, or at any time thereafter, the Division may require an owner or operator to provide monitoring or testing methods and results demonstrating, to the satisfaction of the Division, the amount of negligible-reactive compounds in the source's emissions.

II.B. Exemptions

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

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

II.C. New Sources

All new sources shall utilize controls representing RACT, pursuant to Regulation Number 7, Number 24, Number 25, and Number 26 and Regulation Number 3, Part B, Section III.D., upon commencement of operation.

II.D. Alternative Control Plans and Test Methods

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

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

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

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

Appendix A Colorado Ozone Nonattainment or Attainment Maintenance Areas

I. Chronology of Attainment Status

Denver Metropolitan Area Only

1978 Denver 1-hour Ozone Nonattainment Area designation first becomes effective in 7-county Denver Metropolitan Area

10/11/01 Denver 1-hour Ozone Attainment Maintenance Area designation replaces non-attainment designation and becomes effective in 7-county Denver Metropolitan Area

9/2/05 1-hour Ozone National Ambient Air Quality Standard is Revoked in Colorado except for the Denver 1-hour Ozone Attainment Maintenance Area.

Denver Metropolitan Area and North Front Range

10/11/01 1-hour attainment maintenance area replaces non-attainment designation for the Denver Metro Area/North Front Range Area

4/15/04 EPA designates the Denver Metro Area/North Front Range region as an 8-hour ozone non-attainment area, designation deferred due to the implementation of the Early Action Compact

11/20/07 Denver 8-hour ozone non-attainment designation (1997 NAAQS) becomes effective in 9 county Denver Metropolitan Area

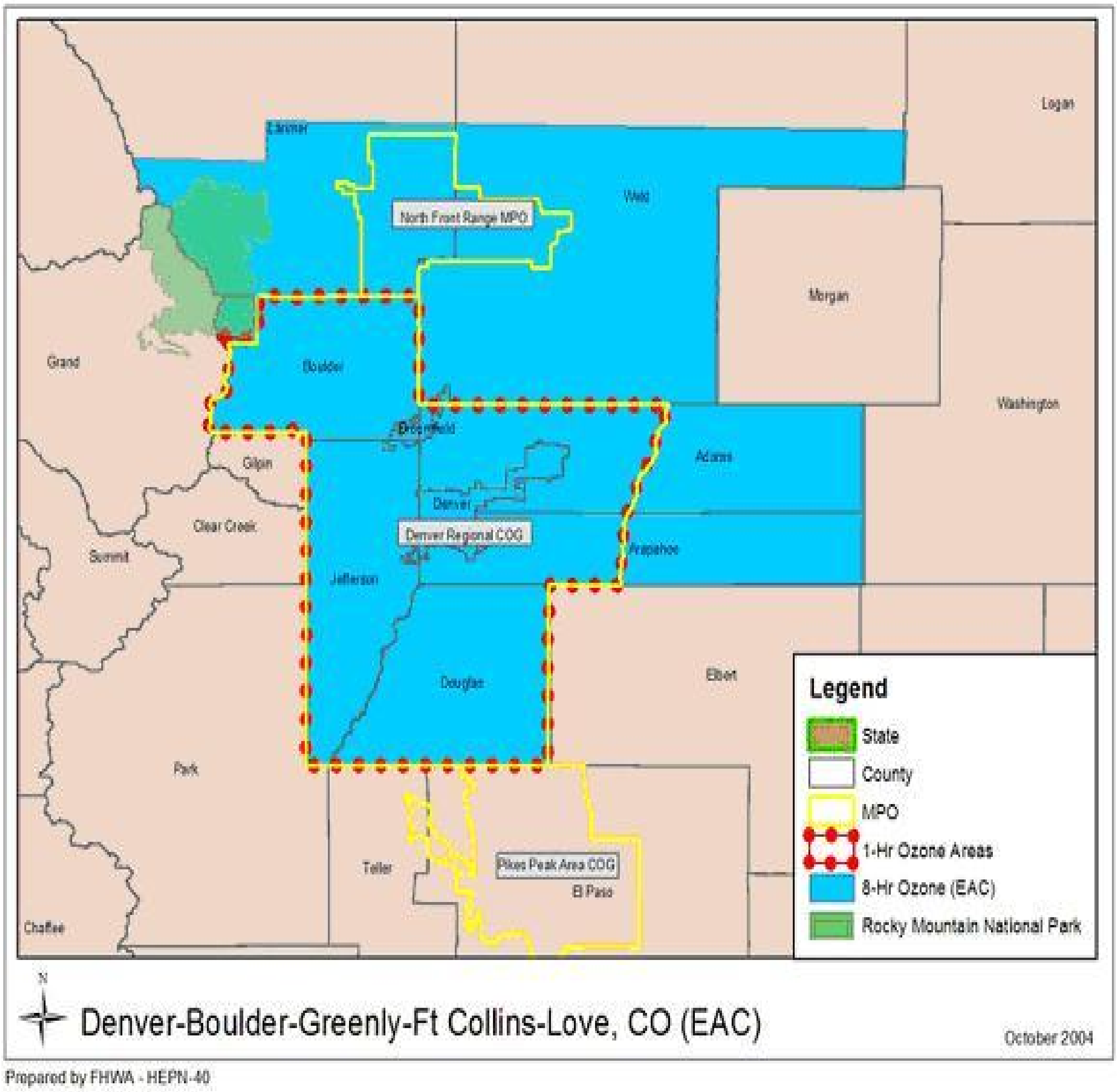
7/20/2012 Denver 8-hour ozone non-attainment designation (2008 NAAQS) becomes effective in 9 county Denver Metropolitan Area

8/3/2018 Denver 8-hour ozone nonattainment designation (2015 NAAQS) becomes effective in 9 county Denver Metropolitan Area

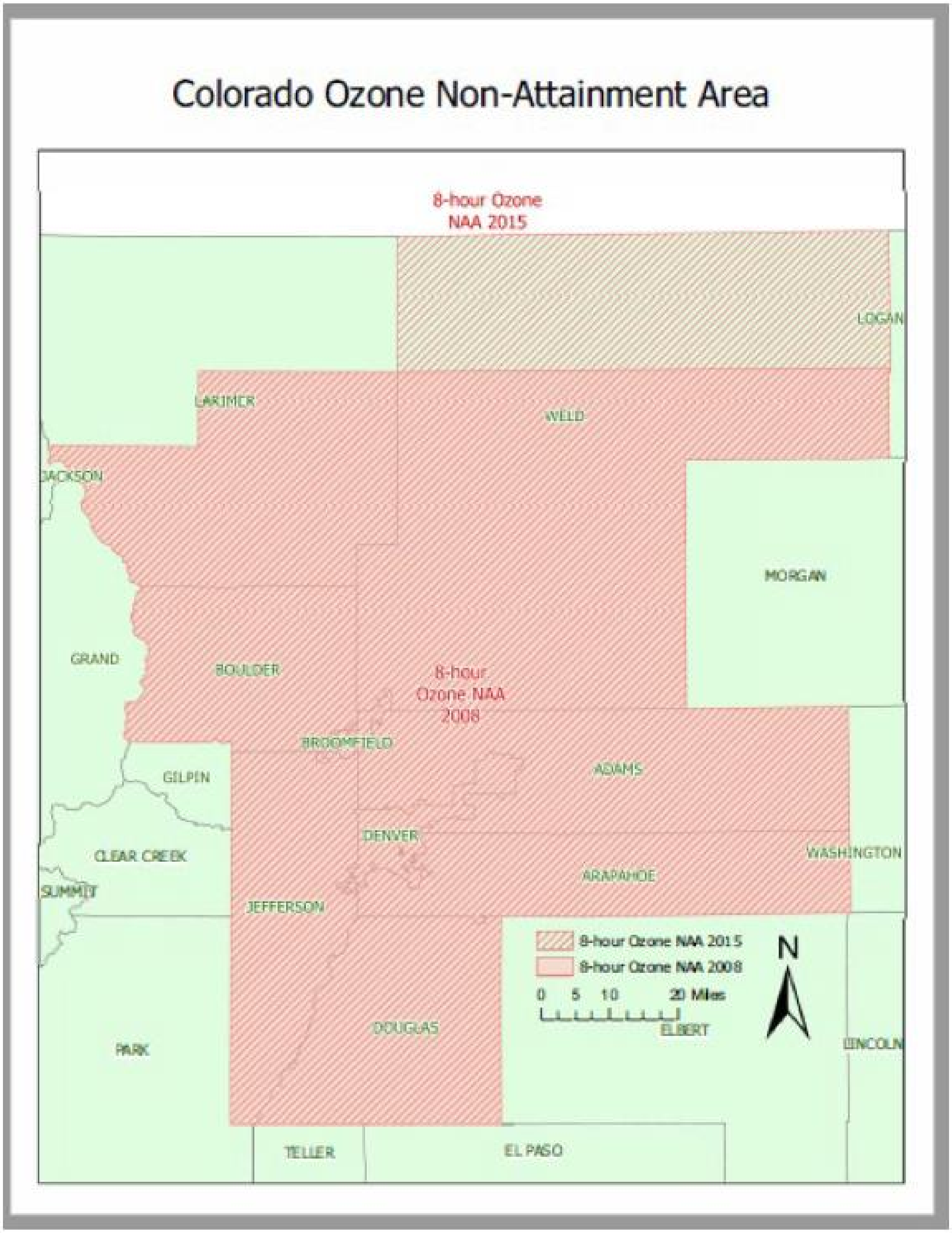
12/31/2021 EPA modification of the 9 county Denver Metropolitan Area 8-hour ozone nonattainment designation (2015 NAAQS) to include the portion of northern Weld County defined in Part A

II. Maps

Denver Metropolitan Area and North Front Range (2008 Ozone NAAQS)



Denver Metropolitan Area and North Front Range and northern Weld County (2015 ozone NAAQS)



PART B Oil and Natural Gas Operations

I. Volatile Organic Compound Emissions from Oil and Gas Operations

I.A. Applicability

I.A.1. Except as provided in Section I.A.4., this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in the 8-hour Ozone Control Area and that are located at or upstream of a natural gas plant.

I.A.2. Except as provided in Section I.A.4., beginning February 14, 2023, this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in northern Weld County and that are located at or upstream of a natural gas plant.

I.A.3. Beginning February 14, 2023, this section applies to centralized oil stabilization facilities that emit or have the potential to emit VOC emissions greater than or equal to 25 tpy as of November 7, 2022, located in the 8-Hour Ozone Control Area.

I.A.4. Beginning February 14, 2023, Sections I.B. through I.F. and I.M. apply to class II disposal well facilities that emit or have the potential to emit VOC emissions greater than or equal to 25 tpy as of November 7, 2022, located in the 8-Hour Ozone Control Area.

I.A.5. Oil refineries are not subject to Section I.

I.B. Definitions specific to Section I.

I.B.1. “Affected Operations” means oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations, to which Section I. applies.

I.B.2. “Air Pollution Control Equipment”, as used in Section I., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment, pollution prevention devices, and processes that comply with the requirements of Section I.D.4. that are approved by the Division.

I.B.3. “Approved Instrument Monitoring Method” means an infra-red camera, EPA Method 21, or other instrument based monitoring method or program approved in accordance with Section I.L.8. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection, recordkeeping, and reporting program for such operations.

I.B.4. “Atmospheric Storage Tanks or Atmospheric Condensate Storage Tanks” means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.

I.B.5. “Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

I.B.6. “Calendar Week” means a week beginning with Sunday and ending with Saturday.

I.B.7. "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.

I.B.8. "Commencement of Operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

I.B.9. "Condensate Storage Tank" means any tank or series of tanks that store condensate and are either manifolded together or are located at the same well pad.

I.B.10. "Centralized Oil Stabilization Facility" means a facility that receives high-vapor-pressure crude oil (post-separation) from well production facilities through a pipeline oil-gathering system and stabilizes the crude oil for storage in tanks and/or for pipeline transportation.

I.B.11. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

I.B.12. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

I.B.13. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

I.B.14. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

I.B.15. "Downtime" means the period of time when a well is producing and the air pollution control equipment is not in operation.

I.B.16. "Existing" means any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.

I.B.17. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

I.B.18. "Hydrocarbon liquids" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquids does not include produced water.

I.B.19. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

I.B.20. "Modified or Modification" means any physical change or change in operation of a stationary source that results in an increase in actual uncontrolled volatile organic compound emissions from the previous calendar year that occurs on or after February 1, 2009. For atmospheric condensate storage tanks (and beginning March 1, 2020, for all storage tanks), a physical change or change in operation includes but is not limited to drilling wells and recompleting, refracturing or otherwise stimulating existing wells.

I.B.21. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

I.B.22. "Natural Gas-Driven Diaphragm Pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

I.B.23. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

I.B.24. "New" means any atmospheric condensate storage tank that began operation on or after February 1, 2009.

I.B.25. "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.

I.B.26. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

I.B.27. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

I.B.28. "Stabilized" when used to refer to stored hydrocarbon liquids, means that the hydrocarbon liquids have reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses".

I.B.29. "Storage tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

I.B.30. "Storage vessel" means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

I.B.31. (State Only) "Surveillance System" means monitoring pilot flame presence or temperature in a combustion device either by visual observation or with an electronic device to record times and duration of periods where a pilot flame is not detected at least once per day.

I.B.32. "System-Wide Control Strategy" means the collective emissions and emission reductions from all atmospheric condensate storage tanks under common ownership within the 8-hour Ozone Control Area for which uncontrolled actual volatile organic compound emissions are equal to or greater than two tons per year.

I.B.33. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

I.C. General Provisions

I.C.1. General Requirements

I.C.1.a. All air pollution control equipment used to demonstrate compliance with this Section I. must be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates required by this Section I. and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

I.C.1.b. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable.

I.C.1.c. All air pollution control equipment used to demonstrate compliance with Sections I.D., I.J., and I.K. must meet a control efficiency of at least 95%. Failure to properly install, operate, and maintain air pollution control equipment is a violation of this regulation.

I.C.1.d. If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly.

I.C.1.e. All combustion devices used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. must be equipped with and operate an auto-igniter as follows:

I.C.1.e.(i) (State Only) For condensate storage tanks that are constructed or modified after May 1, 2009, and before January 1, 2017, and controlled by a combustion device, auto-igniters must be installed and operational, beginning the date of first production after any new tank installation or tank modification.

I.C.1.e.(ii) (State Only) For all existing condensate storage tanks controlled by a combustion device in order to comply with the emissions control requirements of Section I.D.1., auto-igniters must be installed and operational beginning May 1, 2009, for condensate storage tanks with actual uncontrolled emissions of greater than or equal to 50 tons per year, and beginning May 1, 2010, for all other existing condensate storage tanks controlled by a combustion device, or within 180 days from first having installed the combustion device, whichever date comes later.

I.C.1.e.(iii) All combustion devices installed on or after January 1, 2017, must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.e.(iv) All combustion devices installed on or after January 1, 2018, and used to comply with Sections I.J. or I.K. must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.f. (State Only) If a combustion device is used to control emissions of volatile organic compounds, surveillance systems must be employed and operational as follows:

I.C.1.f.(i) (State Only) Beginning May 1, 2010, for all existing condensate storage tanks with uncontrolled actual emissions of 100 tons per year or more based on data from the previous twelve consecutive months.

I.C.1.f.(ii) (State Only) For all new and modified condensate storage tanks controlled by a combustion device for the first 90 days surveillance systems must be employed and operational beginning 180 days from commencement of operation after the tank was newly installed, or after the well was newly drilled, re-completed, re-fractured or otherwise stimulated, if uncontrolled actual emissions projected for the first twelve months based on data from the first 90 days of operation from the condensate storage tank are 100 tons or more of uncontrolled VOCs.

I.C.2. The emission estimates and emission reductions required by Section I.D. must be demonstrated using one of the following emission factors:

I.C.2.a. In the 8-Hour Ozone Control Area

I.C.2.a.(i) For atmospheric condensate storage tanks at oil and gas exploration and production operations, a default emission factor of 13.7 pounds of volatile organic compounds per barrel of condensate must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii). The Division may require a more specific emission factor that complies with Section I.C.2.a.(iii).

I.C.2.a.(ii) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations a source may use a specific emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003. The Division may, however, require the source to develop and use a more recent specific emission factor pursuant to Section I.C.2.a.(iii) if such a more recent emission factor would be more reliable or accurate.

I.C.2.a.(iii) Except as otherwise provided in Section I.C.2.a.(i), a specific emission factor is one for which the Division has no objection, and which is based on collection and analysis of a representative sample of the hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.a.(iv) For storage tanks storing produced water or hydrocarbon liquids other than condensate, the most recent Division-approved default emission factors must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii).

I.C.2.a.(v) If the Division has reason to believe that a specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require the use of an alternative emission factor that complies with Section I.C.2.a.(iii).

I.C.2.b. (State Only) For any other Ozone Nonattainment Area or Attainment/Maintenance Areas

I.C.2.b.(i) (State Only) For storage tanks at oil and gas exploration and production operations, the source must use a default basin-specific uncontrolled volatile organic compound emission factor established by the Division unless a site-specific emission factor has been established pursuant to Section I.C.2.b.(iii). If the Division has established no default emission factor, if the Division has reason to believe that the default emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(ii) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, the source must use a site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.(iii). If the Division has reason to believe that the site-specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(iii) (State Only) Establishment of or Updating Approved Emission Factors

I.C.2.b.(iii)(A) (State Only) The Division may require the source to develop and/or use a more recent default basin-specific or site-specific volatile organic compound emission factor pursuant to Section I.C.2.b., if such emission factor would be more reliable or accurate.

I.C.2.b.(iii)(B) (State Only) For storage tanks at oil and gas exploration and production operations, the source may use a site-specific volatile organic compound emission factor for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.b.(iii)(C) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, a source may use a volatile organic compound emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003, or an alternative site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.

I.C.2.b.(iii)(D) (State Only) A default basin-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water or an alternative method, pursuant to a test method approved by the Division, except as otherwise provided in I.C.2.b.(i).

I.C.2.b.(iii)(E) (State Only) A site-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.D. Storage Tank Emission Controls

I.D.1. Repealed (December 16, 2022)

I.D.2. Repealed (December 16, 2022)

I.D.3. Storage Tank Control Strategy

I.D.3.a. Applicability

I.D.3.a.(i) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.a.(ii) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total and not subject to Section I.D.3.a.(i) must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.a.(iii) Internal floating roof tanks subject to Part B, Section IV. at centralized oil stabilization facilities are not subject to Section I.D.3.

I.D.3.a.(iv) Owners or operators of storage tanks at class II disposal well facilities for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply for an exemption from the control requirements of Section I.D.3. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment.

I.D.3.b. Compliance Deadlines

Sections I.D.3.b.(i) through I.D.3.b.(viii) do not apply to storage tanks in northern Weld County or at a centralized oil stabilization or class II disposal well facility specified in Sections I.A.3. or I.A.4.

I.D.3.b.(i) A storage tank subject to Section I.D.3.a.(i) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(ii) A storage tank subject to Section I.D.3.a.(ii) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(iii) A storage tank subject to Section I.D.3.a.(i) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(iv) A storage tank subject to Section I.D.3.a.(ii) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(v) A storage tank subject to Section I.D.3.a.(i) and not otherwise subject to Sections I.D.3.b.(i). or I.D.3.b.(iii) that increases uncontrolled actual emissions to four (4) tons per year VOC or more on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded four (4) tons per year on a rolling twelve-month basis.

I.D.3.b.(vi) A storage tank subject to Section I.D.3.a.(ii) and not otherwise subject to Sections I.D.3.b.(ii) or I.D.3.b.(iv) that increases uncontrolled actual emissions to two (2) tons per year VOC based on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded two (2) tons per year on a rolling twelve-month basis.

I.D.3.b.(vii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iii) or I.D.3.b.(v), compliance with Section I.D.3.a.(i) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iii) or I.D.3.b.(v) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(viii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iv) or I.D.3.b.(vi), compliance with Section I.D.3.a.(ii) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iv) or I.D.3.b.(vi) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(ix) This Section I.D.3. does not apply to storage tanks at natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.3.b.(x) A storage tank in northern Weld County at a centralized oil stabilization or class II disposal well facility specified in Sections I.A.3. or I.A.4. meeting the applicability in Sections I.D.3.a.(i) or I.D.3.a.(ii) and constructed before February 14, 2023, that is not already controlled under Section II.C.1.c. must be in compliance by May 1, 2023.

I.D.3.b.(xi) A storage tank in northern Weld County at a centralized oil stabilization or class II disposal well facility specified in Sections I.A.3. or I.A.4. meeting the applicability in Sections I.D.3.a.(i) or I.D.3.a.(ii) and constructed on or after February 14, 2023, must be in compliance by commencement of operation.

I.D.3.b.(xii) A storage tank in northern Weld County at a centralized oil stabilization or class II disposal well facility specified in Sections I.A.3. or I.A.4. meeting the applicability in Sections I.D.3.a.(i) or I.D.3.a.(ii) that increases uncontrolled actual emissions to two (2) tons per year VOC based on a rolling twelve-month basis after February 14, 2023, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded two (2) tons per year on a rolling twelve-month basis.

I.D.3.b.(xiii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(x) through I.D.3.b.(xii), compliance with Sections I.D.3.a.(i) or I.D.3.a.(ii) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(x) through I.D.3.b.(xii) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.4. Alternative emissions control equipment and pollution prevention devices and processes installed and implemented after June 1, 2004, shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and/or vapor recovery units to achieve the emission reductions required by this Section I.D., if the following conditions are met:

I.D.4.a. The owner or operator obtains a construction permit authorizing such use of the alternative emissions control equipment or pollution prevention device or process. The proposal for such equipment, device or process shall comply with all regulatory provisions for construction permit applications and shall include the following:

I.D.4.a.(i) A description of the equipment, device or process;

I.D.4.a.(ii) A description of where, when and how the equipment, device or process will be used;

I.D.4.a.(iii) The claimed control efficiency and supporting documentation adequate to demonstrate such control efficiency;

I.D.4.a.(iv) An adequate method for measuring actual control efficiency; and

I.D.4.a.(v) Description of the records and reports that will be generated to adequately track emission reductions and implementation and operation of the equipment, device or process, and a description of how such matters will be reflected in the records and reports required by Section I.F.

I.D.4.b. Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.D.4.c. EPA approves the proposal. The Division shall transmit a copy of the permit application and any other materials provided by the applicant, all public comments, all Division responses and the Division’s permit to EPA Region 8. If EPA fails to approve or disapprove the proposal within 45 days of receipt of these materials, EPA shall be deemed to have approved the proposal.

I.E. Monitoring of Storage Tanks and Air Pollution Control Equipment

I.E.1. Applicability

I.E.1.a. The owner or operator of any storage tank that is being controlled pursuant to this Section I.

I.E.2. Monitoring Requirements

I.E.2.a. The owner or operator of any storage tank controlled by air pollution control equipment other than a combustion device must follow manufacturer's recommended maintenance. Air pollution control equipment must be periodically inspected to ensure proper maintenance and operation according to the Division-approved operation and maintenance plan.

I.E.2.b. Repealed (December 16, 2022)

I.E.2.c. Weekly Monitoring Requirements

The owner or operator must inspect or monitor the air pollution control equipment at least weekly to ensure that it is operating properly. The inspection must include and document the following

I.E.2.c.(i) For combustion devices, a check that the pilot light is lit by either visible observation or other means approved by the Division. For devices equipped with an auto-igniter, a check that the auto-igniter is properly functioning.

I.E.2.c.(ii) For combustion devices, a check that the valves for piping of gas to the pilot light are open.

I.E.2.c.(iii) (State Only) In addition to complying with Sections I.E.2.c.(i). and I.E.2.c.(ii)., the owner or operator of tanks controlled pursuant to Section I.D. that have installed combustion devices may use a surveillance system to maintain records on combustion device operation.

I.E.2.c.(iv) For combustion devices, the owner or operator must visually check for the presence or absence of smoke and that the burner tray is not visibly clogged.

I.E.2.c.(v) For vapor recovery units, the owner or operator must check that the unit is operating and that vapors from the storage tank are being routed to the unit.

I.E.2.c.(vi) For all control devices, the owner or operator must check that the valves for the piping from the storage tank to the air pollution control equipment are open.

I.E.2.c.(vii) For all storage tanks, the owner or operator must check that the thief hatch is closed and latched, the pressure relief valve is properly seated, and all vent lines are closed.

I.E.2.c.(viii) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.c.(ix) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks subject to Section I.D.3.a.(ii) must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.d. (State Only) For storage tanks equipped with a surveillance system or other Division-approved monitoring system, the owner or operator must check weekly that the system is functioning properly and that necessary information is being collected. Any loss of data or failure to collect required data may be treated by the Division as if the data were not collected.

I.E.3. Performance testing requirements

I.E.3.a. Each storage vessel that has the potential for VOC emissions equal to or greater than six (6) tons per year (controlled actual emissions) must conduct periodic performance testing of the control device used to comply with Section I.D.3.a.(i). The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for the 30-day period of production prior to May 1, 2022, or April 1, 2023, if located in northern Weld County. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local, or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU with a cover and closed vent system is not required to be included in the determination of VOC potential to emit for purposes of determining applicability.

I.E.3.a.(i) Conduct a performance test in accordance with 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(b) (June 3, 2016) by May 1, 2023, and subsequent performance tests no longer than 60 months following the previous performance test.

I.E.3.a.(ii) Control device models tested in accordance with 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(d) and demonstrating continuous compliance in accordance with 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(e)(1) (June 3, 2016) are not subject to the performance test requirement in Section I.E.3.a.(i).

I.E.3.a.(iii) Maintain records of performance tests conducted pursuant to Section I.E.3.a.(i) or manufacturer demonstrations and associated inlet gas flow rate records specified in Section I.E.3.a.(ii) for five (5) years and make records available to the Division upon request.

I.F. Storage Tank Recordkeeping and Reporting

I.F.1. Repealed, except for records retained in Sections I.F.1.c. through 1.F.1.f. and I.F.1.g.(x); renumbered as I.F.1.a. through I.F.1.e., respectively. (December 16, 2022)

I.F.1.a. A copy of each calendar weekly and calendar monthly spreadsheet shall be retained for five years, with final retention period ending April 30, 2025. A spreadsheet may apply to more than one week if there are no changes in any of the required data and the spreadsheet clearly identifies the weeks it covers. The spreadsheet may be retained electronically. However, the Division may treat any loss of data or failure to maintain the Division-approved spreadsheet, as if the data were not collected.

I.F.1.b. Each owner or operator shall maintain records of the inspections required pursuant to Section I.E. and retain those records for five years, with final retention period ending April 30, 2025. These records shall include the time and date of the inspection, the person conducting the inspection, a notation that each of the checks required under Sections I.C. and I.E. were completed and a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

I.F.1.c. (State Only) Each owner or operator shall maintain records of required surveillance system or other monitoring data and shall make these records available promptly upon Division request.

I.F.1.d. (State Only) Each owner or operator shall maintain records on when an atmospheric condensate storage tank is newly installed, or when a well is newly drilled, re-completed, re-fractured or otherwise stimulated. Records shall be maintained per well associated with each tank and the date of first production associated with these activities.

I.F.1.e. A copy of each semi-annual report shall be retained for five years or through August 30, 2025, for the last report submitted on or before August 30, 2020.

I.F.2. Recordkeeping for storage tanks subject to Section I.D.3.

I.F.2.a. The owner or operator of any storage tank subject to control pursuant to Section I.D.3. must maintain records and make them available to the Division upon request.

I.F.2.b. Records maintained under this Section I.F.2. must include:

I.F.2.b.(i) The AIRS number for the storage tank. The AIRS number assigned by the Division must be marked on all storage tanks required to file an APEN.

I.F.2.b.(ii) If air pollution control equipment is required to comply with Section I.D.3. visible signage must be located with the control equipment identifying the AIRS number for each storage tank that is being controlled by that equipment.

I.F.2.b.(iii) Records of the inspections required in Section I.E.

I.F.2.b.(iii)(A) The time and date of each inspection.

I.F.2.b.(iii)(B) The person conducting the inspection.

I.F.2.b.(iii)(C) A notation that each of the checks required under Section I.E. were completed.

I.F.2.b.(iii)(D) A description of any problems observed during the inspection, description and date of any corrective actions taken, and name of individual performing corrective actions.

I.F.2.b.(iv) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month totals for each storage tank subject to control under Section I.D.3.

I.F.2.b.(v) The emission factor used for each storage tank. The emission factors must comply with Section I.C.2. and the owner or operator must use the most recent emission factor on file with the Division (i.e., either the default emission factor or the specific emission factor established pursuant to Section I.C.2.a.(iii)).

I.F.2.b.(vi) The control efficiency of each unit of air pollution control equipment and the AIRS number of the storage tank being controlled.

I.F.2.b.(vii) Records of any exemption, and associated documentation, applied for under Section I.D.3.a.(ii)(A).

I.F.2.c. (State Only) The owner or operator of each storage tank subject to Section I.D.3. (except storage tanks located at centralized oil stabilization and class II disposal well facilities specified in Section I.A.4.) must maintain records of

I.F.2.c.(i) The monthly production volumes for each storage tank, based on the most recent measurement available. The monthly average must be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the purchaser for delivery of hydrocarbon liquids or produced water from such tank, over the time such delivered hydrocarbon liquids or produced water was collected. The monthly average from the most recent measurement will be used to estimate monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.2.c.(ii) Any downtime of air pollution control equipment, including the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.2.c.(iii) Any required surveillance system or other monitoring data.

I.F.2.c.(iv) When a storage tank is installed, or when a well is drilled, re-completed, re-fractured, or otherwise stimulated. Records must be maintained per well associated with each storage tank and the date of commencement of operation associated with these activities.

I.F.3. Reporting for storage tanks subject to Section I.D.3.

I.F.3.a. On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks in the 8-Hour Ozone Control Area must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.b. On or before April 30, 2024, and April 30 of each year thereafter, the owner or operator of any storage tank subject to Sections I.D.3.b.(x) through I.D.3.b.(xii) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.c. The report under this Section I.F.3. must include:

I.F.3.c.(i) The report must list all storage tanks (by AIRS number and location name) controlled pursuant to Section I.D.3. during the previous calendar year (starting calendar year 2020) and

I.F.3.c.(i)(A) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month total for each storage tank.

I.F.3.c.(i)(B) The emission factor used for each storage tank for each month.

I.F.3.c.(i)(C) The control efficiency for the air pollution control equipment for each storage tank.

I.F.3.c.(ii) (State Only) The report must identify any storage tank whose control status has changed, and the date of the change, since submission of the previous report.

I.F.3.c.(iii) (State Only) The report must list the production volume for each storage tank. Production volumes may be estimated by the amounts shown on the receipt from the purchaser.

I.F.3.c.(iv) (State Only) The report must list any downtime of air pollution control equipment, including the date, time, and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating must be recorded in the report.

I.F.3.c.(v) (State Only) The report must list any instances where the air pollution control equipment was not properly functioning, including the date and time the equipment was not properly operating, the date and time the equipment was last observed operating properly, and the date and time the problem was corrected. The report must also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number, or site name if no AIRS number has been assigned, of each storage tank being controlled by the equipment and the estimated production from those storage tanks during the period of non-operation.

I.F.3.c.(vi) (State Only) Reports must be signed by a responsible official who must also sign the Division-approved compliance certification form for storage tanks. The compliance certification includes both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, the certification must include the citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions must be identified separately from compliance certifications required under the State Implementation Plan.

I.F.3.c.(vii) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. must contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

I.G. Natural gas-processing plants located in the 8-hour Ozone Control Area or northern Weld County shall comply with requirements of this Section I.G., as well as the requirements of Sections I.B., I.C.1.a., I.C.1.b., I.H., I.J., I.K., and Regulation Number 26, Part B, Section I.A. through C.

I.G.1. For fugitive volatile organic compound emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOO (July 1, 2017) applies, regardless of the date of construction of the affected facility, unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOOa (July 1, 2017).

I.G.2. Air pollution control equipment shall be installed and properly operated to reduce emissions of volatile organic compounds from any atmospheric condensate storage tank (or tank battery) used to store condensate that has not been stabilized that has uncontrolled actual emissions of greater than or equal to two tons per year. Such air pollution control equipment shall have a control efficiency of at least 95%.

I.G.3. Natural gas processing plants within the 8-hour Ozone Control Area constructed before January 1, 2018, must comply with the requirements of Section I.G. beginning January 1, 2019.

I.G.4. Natural gas processing plants within northern Weld County must comply with the requirements of Section I.G. beginning February 14, 2023, or upon commencement of operation if after February 14, 2023.

I.G.5. The provisions of Sections I.B., I.C.1.a., I.C.1.b., I.G., I.H., I.J., I.K., and Regulation Number 26, Part B, Section I.A. through C., apply upon the commencement of operations to any natural gas processing plant that commences operation in the 8-Hour Ozone Control Area after the effective date of this section.

I.H. Emission Reductions from glycol natural gas dehydrators

I.H.1. Beginning May 1, 2005, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in the 8-Hour Ozone Control Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.2. (State Only) Beginning January 30, 2009, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in the 8-Hour Ozone Control Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.3. The control requirements of Sections I.H.1. and I.H.2. apply where:

I.H.3.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than one ton per year; and

I.H.3.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than one ton per year.

I.H.4. Beginning February 14, 2023, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in northern Weld County and subject to control requirements pursuant to Section I.H.4. that is not already controlled under Section II.D., must reduce uncontrolled actual emissions of volatile organic compounds by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. The control requirements of Section I.H.4. apply where

I.H.4.a. Uncontrolled actual emissions of VOCs from a glycol natural gas dehydrator constructed on or after February 14, 2023, are equal to or greater than two (2) tons per year. Such glycol natural gas dehydrators must be in compliance with Section I.H.4. by the date that the glycol natural gas dehydrator commences operation.

I.H.4.b. Uncontrolled actual emissions of VOCs from a single glycol natural gas dehydrator constructed before February 14, 2023, are equal to or greater than six (6) tons per year.

I.H.5. For purposes of Section I.H., emissions from still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator shall be calculated using a method approved in advance by the Division.

I.H.6. Monitoring and recordkeeping

I.H.5.a. Beginning January 1, 2017, or February 14, 2023, if located in northern Weld County, owners or operators of glycol natural gas dehydrators subject to the control requirements of Sections I.H.1., I.H.2., or I.H.4. must check on a weekly basis that any condenser or air pollution control equipment used to control emissions of volatile organic compounds is operating properly, and document:

I.H.6.a.(i) The date of each inspection;

I.H.6.a.(ii) A description of any problems observed during the inspection of the condenser or air pollution control equipment; and

I.H.6.a.(iii) A description and date of any corrective actions taken to address problems observed during the inspection of the condenser or air pollution control equipment.

I.H.6.b. The owner or operator must check and document on a weekly basis that the pilot light on a combustion device is lit, that the valves for piping of gas to the pilot light are open, and visually check for the presence or absence of smoke.

I.H.6.c. The owner or operator must document the maintenance of the condenser or air pollution control equipment, consistent with manufacturer specifications or good engineering and maintenance practices.

I.H.6.d. The owner or operator must retain records for a period of five years and make these records available to the Division upon request.

I.H.7. Reporting

I.H.7.a. On or before November 30, 2017, and semi-annually by April 30 and November 30 of each year thereafter, the owner or operator must submit the following information for the preceding calendar year (April 30 report) and for May 1 through September 30 (November 30 report) using Division-approved format. Owners or operators of glycol natural gas dehydrators in northern Weld County must submit the first April 30 report on or before April 30, 2024 (for calendar year 2023), and each April 30 thereafter, and the first November 30 report on or before November 30, 2023, (for May 1 through September 30), and each year thereafter, using Division-approved format.

I.H.7.a.(i) A list of the glycol natural gas dehydrator(s) subject to Section I.H.;

I.H.7.a.(ii) A list of the condenser or air pollution control equipment used to control emissions of volatile organic compounds from the glycol natural gas dehydrator(s); and

I.H.7.a.(iii) The date(s) of inspection(s) where the condenser or air pollution control equipment was found not operating properly or where smoke was observed.

I.I. The requirements of Sections I.D. through I.F. do not apply to the owner or operator of any natural gas compressor station or natural gas drip station located in an Ozone Nonattainment or Attainment/Maintenance Area if:

I.I.1. Air pollution control equipment is installed and properly operated to reduce emissions of volatile organic compounds from all atmospheric condensate storage tanks (or tank batteries) that have uncontrolled actual emissions of greater than or equal to two tons per year;

I.I.2. The air pollution control equipment is designed to achieve a VOC control efficiency of at least 95% on a rolling 12-month basis and meets the requirements of Sections I.C.1.a. and I.C.1.b;

I.I.3. The owner or operator of such natural gas compressor station or natural gas drip station does not own or operate any exploration and production facilities in the Ozone Non-attainment or Attainment-maintenance Area; and

I.I.4. The owner or operator of such natural gas compressor station or natural gas drip station does the following and maintains associated records and reports for a period of five years:

I.I.4.a. Documents the maintenance of the air pollution control equipment according to manufacturer specifications;

I.I.4.b. Conducts an annual opacity observation once each year on the air pollution control equipment to verify opacity does not exceed 20% during normal operations;

I.I.4.c. Maintains records of the monthly stabilized condensate throughput and monthly actual VOC emissions; and

I.I.4.d. Reports compliance with these requirements to the Division annually.

I.I.5. A natural gas compressor station or natural gas drip station subject to Section I.I. at which a glycol natural gas dehydrator and/or natural gas-fired stationary or portable engine is operated is subject to Sections I.H., I.J., and/or Regulation Number 26, Part B, Section I. A natural gas compressor station subject to Section I.I. is also subject to Section I.L.

I.J. Compressors

I.J.1. Centrifugal compressor

I.J.1.a. Beginning January 1, 2018, or May 1, 2023, if located in northern Weld County, uncontrolled actual volatile organic compound emissions from wet seal fluid degassing systems on wet seal centrifugal compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be reduced by at least 95%. A centrifugal compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.1.

I.J.1.b. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must equip the wet seal fluid degassing system with a continuous, impermeable cover that is connected through a closed vent system that routes the emissions from the wet seal fluid degassing system to the process or control device.

I.J.1.c. The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.1.d. The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.1.e. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.1.f. Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.1.f.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.1.f.(ii) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.1.f.(iii) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.1.f.(iv) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.1.g. The owner or operator must conduct monthly inspections of a combustion device used to reduce emissions to ensure the device is operating with no visible emissions. 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. Devices fail the visible emissions test if a Method 22 observation documents visible emissions are present for more than one minute in any 15-minute period. Devices failing the visible emissions test must follow manufacturer’s repair instructions, if available, or best combustion engineering practice to return the unit to compliant operation. Following return to operation, the owner or operator must complete a Method 22 visual observation where there are less than one minute of visible emissions in any 15-minute period.

I.J.1.h. For a combustion device used to reduce VOC emissions from wet seal fluid degassing systems on wet seal centrifugal compressors, the owner or operator must conduct a performance test in accordance with 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(b) (June 3, 2016) by May 1, 2023, or May 1, 2024, if located in northern Weld County, and subsequent performance tests no longer than 60 months following the previous performance test. Control device models tested in accordance with 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(d) and demonstrating continuous compliance in accordance with 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(e)(1) (June 3, 2016) are not subject to the performance test requirement.

I.J.1.i. Recordkeeping

I.J.1.i.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.1.i.(i)(A) Identification of each centrifugal compressor using a wet seal system;

I.J.1.i.(i)(B) Each combustion device visible emissions inspection and any resulting responsive actions;

I.J.1.i.(i)(C) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.1.i.(i)(D) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.1.i.(i)(E) Each performance test or manufacturer demonstration of control device model performance test, and associated inlet gas flow rate records.

I.J.1.i.(i)(F) Records of visual inspections conducted pursuant to Section I.J.1.g., 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).

I.J.1.j. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.1.c. through I.J.1.f., I.J.1.h.(i)(C), and I.J.1.h.(i)(D), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.1.k. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.1.a. through I.J.1.i., the owner or operator may comply with wet seal centrifugal compressors emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.J.2. Reciprocating compressor

I.J.2.a. Beginning January 1, 2018, or February 14, 2023, if located in northern Weld County, the rod packing on reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be replaced every 26,000 hours of operation or every thirty-six (36) months. A reciprocating compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.2.

I.J.2.a.(i) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed before January 1, 2018, or February 14, 2023, if located in northern Weld County must

I.J.2.a.(i)(A) Begin monitoring the hours of operation starting January 1, 2018, or February 14, 2023, if located in northern Weld County, unless already monitoring under Section II.B.3.; or

I.J.2.a.(i)(B) Conduct the first rod packing replacement required under Section I.J.2. prior to January 1, 2021, or February 14, 2026, if located in northern Weld County, unless under a replacement schedule under Section II.B.3.

I.J.2.a.(ii) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed after January 1, 2018, or February 14, 2023, if located in northern Weld County, must begin monitoring the hours or months of operation upon commencement of operation of the reciprocating compressor, unless the compressor located in northern Weld County is already monitoring under Section II.B.3.d.

I.J.2.b. As an alternative to the requirement described in Section I.J.2.a., beginning May 1, 2018, or February 14, 2023, if located in northern Weld County, the owner or operator may collect rod packing volatile organic compound emissions using a rod packing emissions collection system that operates under negative pressure and routes the rod packing emissions through a closed vent system to a process.

I.J.2.b.(i) The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.2.b.(ii) The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.2.b.(iii) In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.2.b.(iv) Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.2.b.(iv)(A) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.2.b.(iv)(B) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.2.b.(iv)(C) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.2.b.(iv)(D) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.2.c. Recordkeeping

I.J.2.c.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.2.c.(i)(A) Identification of each reciprocating compressor;

I.J.2.c.(i)(B) The hours of operation or the number of months since the previous rod packing replacement, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure;

I.J.2.c.(i)(C) The date of each rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system;

I.J.2.c.(i)(D) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.2.c.(i)(E) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.2.d. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.2.b., I.J.2.c.(i)(D), and I.J.2.c.(i)(E), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.2.e. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.2.a. through I.J.2.d., the owner or operator may comply with reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.K. Pneumatic pumps

I.K.1. Beginning May 1, 2018, or July 1, 2023, if located in northern Weld County, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a natural gas processing plant must ensure the pneumatic pump has a volatile organic compound emission rate of zero.

I.K.2. Beginning May 1, 2018, or July 1, 2023, if located in northern Weld County, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a well production facility must reduce volatile organic compound emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to an existing control device or process at the well production facility. Natural gas-driven diaphragm pneumatic pumps that are in operation during any period of time during a calendar day less than 90 days per calendar year are not subject to Section I.K.2.

I.K.2.a. If the control device available onsite is unable to achieve a 95% emission reduction and it is not technically feasible to route the emissions to a process at the well production facility, the owner or operator must still route the pneumatic pump emissions to the existing control device.

I.K.2.b. If the owner or operator subsequently installs a control device or it becomes technically feasible to route the emissions to a process, the owner or operator must reduce volatile organic compound emissions from the pneumatic pump by 95% within thirty (30) days of startup of the control device or of the feasibility of routing emissions to a process at the well production facility.

I.K.2.c. The owner or operator is not required to control pneumatic pump emissions if, through an engineering assessment by a qualified professional engineer, routing a pneumatic pump to a control device or process at the well production facility is shown to be technically infeasible.

I.K.2.d. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must connect the pneumatic pump through a closed vent system that routes the pneumatic pump emissions to the process or control device.

I.K.2.e. The owner or operator must conduct annual visual inspections of the closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices.

I.K.2.f. The owner or operators must conduct annual EPA Method 21 inspections of the closed vent system to determine whether the closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.K.2.g. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.K.2.h. Owners or operators may delay inspection or repair of a closed vent system if:

I.K.2.h.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.K.2.h.(ii) The closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.K.2.h.(iii) The closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.K.2.h.(iv) The closed vent system is inaccessible to inspect or repair because the closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.K.3. Recordkeeping

I.K.3.a. Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.K.3.a.(i) Identification of each natural gas-driven diaphragm pneumatic pump;

I.K.3.a.(ii) For natural gas-driven diaphragm pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year;

I.K.3.a.(iii) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve;

I.K.3.a.(iv) Records of the engineering assessment and certification by a qualified professional engineer that routing natural gas-driven diaphragm pneumatic pump emissions to a control device or process is technically infeasible;

I.K.3.a.(v) Each closed vent system inspection and any resulting responsive actions; and

I.K.3.a.(vi) Each closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such closed vent system.

I.K.4. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.K.2.e. through I.K.2.h., I.K.3.a.(v), and I.K.3.a.(vi), the owner or operator may inspect, repair, and document the closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.K.5. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.K.1. through I.K.4., the owner or operator may comply with natural gas-driven diaphragm pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.L. Leak detection and repair program for well production facilities and natural gas compressor stations located in the 8-hour Ozone Control Area or northern Weld County, or centralized oil stabilization facilities specified in Section I.A.3.

I.L.1. Natural gas compressor stations

I.L.1.a. Beginning June 30, 2018, or February 14, 2023, if located in northern Weld County, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least quarterly.

I.L.1.b. Owners or operators of natural gas compressor stations constructed on or after June 30, 2018, or February 14, 2023, if located in northern Weld County, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no later than ninety (90) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted at least quarterly.

I.L.2. Well production facilities

I.L.2.a. Beginning June 30, 2018, or February 14, 2023, if located in northern Weld County, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least annually.

I.L.2.b. Beginning June 30, 2018, or February 14, 2023, if located in northern Weld County, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

I.L.2.c. For purposes of Sections I.L.2.a. and I.L.2.b., the estimated uncontrolled actual volatile organic compound emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual volatile organic compound emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

I.L.2.d. Owners or operators of well production facilities constructed on or after June 30, 2018, or February 14, 2023, if located in northern Weld County, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted in accordance with Sections I.L.2.a. and I.L.2.b.

I.L.2.e. Beginning April 1, 2023, owners or operators of centralized oil stabilization facilities specified in Section I.A.3. must inspect components for leaks using an approved instrument monitoring method at least quarterly.

I.L.3. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

I.L.3.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

I.L.3.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

I.L.3.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

I.L.4. Leaks requiring repair: Only leaks from components exceeding the thresholds in Section I.L.4. require repair under Section I.L.5.

I.L.4.a. For EPA Method 21 monitoring, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.b. For infra-red camera monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.c. For other approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in an approval under Section I.L.8.

I.L.4.d. For leaks identified using an approved non-quantitative instrument monitoring method, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section I.L.5. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section I.L.4.a., the leak must be repaired and remonitored in accordance with Section I.L.5.

I.L.4.e. Owners or operators must maintain and operate approved non-quantitative instrument monitoring methods according to manufacturer recommendations.

I.L.5. Repair and remonitoring

I.L.5.a. First attempt to repair a leak must be made no later than five (5) working days after discovery and completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

I.L.5.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

I.L.5.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.L.5.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

I.L.5.b. Within fifteen (15) working days of completion of a repair the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

I.L.5.c. Leaks discovered pursuant to the leak detection methods of Section I.L.4. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section I.L.5. or keep required records in accordance with Section I.L.6.

I.L.6. Recordkeeping

I.L.6.a. Documentation of the initial approved instrument monitoring method inspection for well production facilities and natural gas compressor stations;

I.L.6.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

I.L.6.c. A list of the leaks requiring repair and the monitoring method(s) used to determine the presence of the leak;

I.L.6.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

I.L.6.e. The date the leak was repaired and type of repair method applied;

I.L.6.f. The delayed repair list, including the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list;

I.L.6.g. The date the leak was remonitored and the results of the remonitoring; and

I.L.6.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section I.L.3., an explanation stating why the component is so designated, and the schedule for monitoring such component(s).

I.L.6.i. Records must be maintained for a minimum of five years and made available to the Division upon request.

I.L.7. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section I.L. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019, or May 31st, 2024, if located in northern Weld County or a centralized oil stabilization facilities specified in Section I.A.3) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

I.L.7.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

I.L.7.b. The total number of inspections performed per inspection frequency tier of well production facilities and the total number of inspections performed at natural gas compressor stations;

I.L.7.c. The total number of identified leaks requiring repair broken out by component type, monitoring method, and inspection frequency tier of well production facility as reported in Section I.L.7.b. and the total number of identified leaks requiring repair at natural gas compressor stations broken out by component type and monitoring method;

I.L.7.d. The total number of leaks repaired for each inspection frequency tier of well production facilities as reported in Section I.L.7.b. and the total number of leaks repaired for natural gas compressor stations;

I.L.7.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facility as reported in Section I.L.7.b. or natural gas compressor station, and the basis for each delay of repair;

I.L.7.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

I.L.7.g. Each report shall be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

I.L.8. Alternative approved instrument monitoring methods may be used in lieu of, or in combination with an infra-red camera, EPA Method 21, or other approved instrument monitoring method to inspect for leaks as required by Section I.L., if the following conditions are met:

I.L.8.a. The proponent of the alternative approved instrument monitoring method applies for a determination of an alternative approved instrument monitoring method or program. The application must include, at a minimum, the following:

I.L.8.a.(i) The proposed alternative approved instrument monitoring method manufacturer information;

I.L.8.a.(ii) A description of the proposed alternative approved instrument monitoring method including, but not limited to:

I.L.8.a.(ii)(A) Whether the proposed alternative approved instrument monitoring method is a quantitative detection method, and how emissions are quantified, or qualitative leak detection method;

I.L.8.a.(ii)(B) Whether the proposed alternative approved instrument monitoring method is commercially available;

I.L.8.a.(ii)(C) Whether the proposed alternative approved instrument monitoring method is approved by other regulatory authorities and for what application (e.g., pipeline monitoring, emissions detected);

I.L.8.a.(ii)(D) The leak detection capabilities, reliability, and limitations of the proposed alternative approved instrument monitoring method, including, but not limited to, the ability to identify specific leaks or locations, detection limits, and any restrictions on use, as well as supporting data;

I.L.8.a.(ii)(E) The frequency of measurements and data logging capabilities of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(F) Data quality indicators for precision and bias of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(G) Quality control and quality assurance procedures necessary to ensure proper operation of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(H) A description of where, when, and how the proposed alternative approved instrument monitoring method will be used; and

I.L.8.a.(ii)(I) Documentation (e.g., field or test data, modeling) adequate to demonstrate the proposed alternative approved instrument monitoring method or program is capable of achieving emission reductions that are at least as effective as the emission reductions achieved by the leak detection and repair provisions in Section I.L.

I.L.8.a.(iii) The Division will transmit a copy of the complete application and any other materials provided by the applicant to EPA.

I.L.8.a.(iv) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.L.8.a.(v) The Division and the EPA approves the proposal. The Division will transmit a copy of the application and any other materials provided by the applicant, all public comments, all Division responses and the Division’s approval to EPA Region 8. If EPA fails to approve or disapprove the proposal within six (6) months of receipt of these materials, EPA will be deemed to have approved the proposal.

I.M. Storage tank hydrocarbon liquids loadout requirements at class II disposal well facilities specified in Section I.A.4., well production facilities, natural gas compressor stations, and natural gas processing plants.

I.M.1. Owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with a hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

Owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

I.M.1.a. Compliance with Section I.M. must be achieved in accordance with the following schedule.

I.M.1.a.(i) Facilities constructed or modified on or after February 14, 2023, must be in compliance by commencement of operation

I.M.1.a.(ii) Well production facilities, natural gas compressor stations, and natural gas processing plants that exceed the hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis on or after February 14, 2023, must control emissions from loadout upon exceeding the loadout threshold.

I.M.1.a.(iii) Class II disposal well facilities that exceed the hydrocarbon liquids loadout to transport vehicles emissions threshold of greater than or equal to two (2) tons uncontrolled actual VOC emissions per year on a rolling 12-month basis on or after February 14, 2023, must control emissions from loadout within sixty (60) days of the first day of the month after which loadout emissions exceeded the loadout threshold.

I.M.1.b. Storage tanks must operate without venting at all times during loadout.

I.M.1.c. The owner or operator must, as applicable

I.M.1.c.(i) Install and operate the vapor collection and return equipment to collect vapors during the loadout of hydrocarbon liquids to tank compartments of outbound transport vehicles and to route the vapors to the storage tank or air pollution control equipment.

I.M.1.c.(ii) Include devices to prevent the release of vapor from vapor recovery hoses not in use.

I.M.1.c.(iii) Use operating procedures to ensure that hydrocarbon liquids cannot be transferred to transport vehicles unless the vapor collection and return system is in use.

I.M.1.c.(iv) Operate all recovery and disposal equipment at a back-pressure less than the pressure relief valve setting of transport vehicles.

I.M.1.c.(v) The owner or operator must inspect onsite loading equipment to ensure that hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loadout. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring.

I.M.1.d. Owners or operators must retain records for at least five (5) years and make such records available to the Division upon request.

I.M.1.d.(i) Records of the annual facility hydrocarbon liquids loadout to transport vehicles throughput.

I.M.1.d.(ii) Records of class II disposal well facility VOC emissions from hydrocarbon liquids loadout to transport vehicles on a rolling 12-month basis.

I.M.1.d.(iii) Records of the frequency of loadout.

I.M.1.d.(iv) Inspections, including a description of any problems found and their resolution, required under Section I.M.1.c.(v) must be documented in a log.

I.M.1.d.(v) Air pollution control equipment used to comply with this Section I.M. must comply with Section I.C.1, be inspected in accordance with Sections I.E.2.c.(i), I.E.2.c.(ii), and I.E.2.c.(iv), and achieve a hydrocarbon control efficiency of 95%.

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 or piping to reduce system pressure. Blowdown includes venting as defined in Section II.C.2.a.(i)(B) where the venting was intentional.

II.A.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.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.7. "Closed Liquids Containment System" as used in Section II.H. means an assembly of piping and valves that allow for the transfer of liquid from a pigging unit to a pipeline or pressurized vessel at the operating pressure of the midstream gathering pipeline.

II.A.8. "Commencement of Operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

II.A.9. "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.10. "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.11. "Disproportionately Impacted Community" (DI community) means census block groups designated as DI communities in CDPHE's Data Viewer for Disproportionately Impacted Communities (as of December 17, 2021), at https://cohealthviz.dphe.state.co.us/t/EnvironmentalEpidemiologyPublic/views/EJActDICommunities-Public/HB21-1266DICommunities?%3AshowAppBanner=false&%3Adisplay_count=n&%3AshowVizHome=n&%3Aorigin=viz_share_link&%3AisGuestRedirectFromVizportal=y&%3Aembed=y consistent with 24-4-109(2)(b)(II), C.R.S. (2021). A complete list of these census block groups by 12-digit FIPS code will be maintained by the Division and made publicly available.

II.A.12. "Dump Valve" means a liquid-control valve in a separator that controls liquid level within the separator vessel.

II.A.13. "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.14. "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.15. "High-pressure Pigging Pipeline" as used in Section II.H. means a pigging pipeline with a normal operating pressure (average annual operating pressure) of 500 pounds per square inch gauge (psi) or greater.

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. "Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.

II.A.18. “Infra-red Camera” means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

II.A.19. “Jumper Line” means an enclosed piping system attached to the vent line or other connection of a pig launcher or receiver that routes the contents of a pig launcher or receiver into a lower pressure system.

II.A.20. “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 stand-alone pigging station, 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 stand-alone pigging station, natural gas processing plant, transmission pipeline, or direct use.

II.A.21. “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.22. “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.23. “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.24. “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.25. “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.26. “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.27. “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.28. “Oil and Natural Gas Compression Segment” means the oil and natural gas compression, midstream 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.29. “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.30. “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.31. “Pigging” or “Pigging Operations” means the process of introducing or subsequently removing a specialized device (a “pig”) into or out of a natural gas pipeline to remove liquids or debris or for other purposes.

II.A.32. “Pigging Facility” means the facility from where a pig is launched or the facility where a pig is received, including standalone pigging stations, natural gas compressor stations, natural gas processing plants, well sites, or well production facilities.

II.A.33. “Pigging Pipeline” means a pipeline connected to a permanent or temporary pigging unit or any pipeline through which a pig is transported.

II.A.34. “Pigging Unit” means an individual pig launcher or receiver owned or operated by a midstream segment owner or operator where pigging occurs, including both permanent and temporary pig launchers and receivers.

II.A.35. “Process drain” as used in Section II.H. means an enclosed drain located on the underside of the pig receiver that drains liquids from the receiver into an enclosed system, process, or vessel.

II.A.36. “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.37. “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.38. "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.39. "Standalone Pigging Station" means a pigging unit or group of co-located pigging units owned or operated by a midstream segment owner or operator but not located at a natural gas compressor station or natural gas processing plant.

II.A.40. "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.41. "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.42. "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.43. "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.44. "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.45. "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). These readings must include the maximum and minimum measured flow rate since the previous weekly visual inspection. An owner or operator may use automation to continuously record flow to the enclosed combustion devices(s) 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 enclosed combustion device or bank of enclosed combustion devices, ensuring that the flow meter(s) measures all flow streams to the device or bank of enclosed combustion devices.

II.B.2.g.(i) Unless an extension is authorized by the Division for good cause, flow meters must be installed and operating by

II.B.2.g.(i)(A) December 31, 2022, for enclosed combustion devices in disproportionately impacted communities that commenced operation before February 14, 2022.

II.B.2.g.(i)(B) May 1, 2023, for enclosed combustion devices not subject to Section II.B.2.g.(i)(A) that commenced operation before February 14, 2022.

II.B.2.g.(i)(C) Commencement of operation for enclosed combustion devices that commence 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, if available, or otherwise in accordance with generally accepted calibration and maintenance practices.

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

II.B.2.g.(iii)(A) On portable enclosed combustion devices used at a location for less than 180 consecutive days and which are used for time-limited activities or backup purposes.

II.B.2.g.(iii)(B) On enclosed combustion devices used during vapor recovery unit downtime associated with dehydrators.

II.B.2.g.(iii)(C) Where installation and operation 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, Part B, Sections I.D., II.B.3.b., II.C.1., II.D., or II.F. 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 limited-use 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) With enough time to calibrate and ensure proper reading from the flow meter prior to each performance test conducted under Section II.B.2.h. and continuing through the performance test, owner or operators must install and operate a flow meter on the inlet to each enclosed combustion device to be tested, unless not required by the Division-approved performance test protocol. Temporary flow meters may be used to meet this requirement.

II.B.2.h.(i)(E) For the calendar year of a failing 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 failed test until the enclosed combustion device is back in compliance as confirmed by the passing retest under Section II.B.2.h.(i)(G).

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

II.B.2.h.(i)(G) Owners or operators must retest the enclosed combustion device within ninety (90) days of corrective action in response to a failed test or within thirty (30) days of return to operation if the equipment or operations controlled by the enclosed combustion device were shut-in as a response to a failed test. Division approval of the testing protocol is not required for a retest where.

II.B.2.h.(i)(G)(1) The owner or operator is following the same test protocol as the original, failed test and

II.B.2.h.(i)(G)(2) Conditions have not materially changed such that a new test protocol would be required.

II.B.2.h.(i)(H) As an alternative to Section II.B.2.h.(i)(G), 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 device	Compliance deadlines					
	October 31, 2023	October 31, 2024	May 1, 2025	May 1, 2026	May 1, 2027	May 1, 2028
	Percentage (%) of owner or operator’s enclosed combustion devices that must be tested					
Within a DI community	At least 15%	At least 40%	At least 70%	100%	NA	NA
Within the 8-hour ozone control area and northern Weld County	At least 10%	At least 30%	At least 50%	At least 80%	100%	NA
Outside the 8-hour ozone control area and northern Weld County	At least 5%	At least 15%	At least 30%	At least 50%	At least 75%	100%

II.B.2.h.(ii)(B) A performance test conducted in accordance with Division-approved test protocol between January 1, 2020, and October 31, 2023, will satisfy the initial performance testing requirements in Section II.B.2.h.(ii)(A).

II.B.2.h.(ii)(C) 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)(D) 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)(E) 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)(F) 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, or other unique identifier), 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.(iii)(C) A list of enclosed combustion devices where the initial performance test requirement is satisfied pursuant to Section II.B.2.h.(ii)(B), including the date and results of the test.

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 or other unique identifier, and AIRS ID (if assigned) of each enclosed combustion device; associated facility name and location; and the range of gas flow at which the combustion device is designed to operate.

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 throughput volume, and total 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.(ii)(G).

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

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 required by the test protocol; documentation of the methods and results of the test, including whether the device passed or failed and the tested control efficiency; and the date and description of any actions taken in response to a failed test.

II.B.2.i.(x) Records of flow meter calibration and maintenance conducted pursuant to Section II.B.2.g.(ii), including manufacturer specifications and schedule if available.

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

II.B.2.j.(i) By no later than the final day of the month after the failing test result, the owner or operator must submit a notification of the failing test, including: AIRS ID, serial number or other unique identifier, 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 throughput for the calendar year of the test; the action to return the enclosed combustion device to proper operation (or whether operations were shut-in), including the timing thereof; and the proposed date of the retest.

II.B.2.j.(ii) On the same date as the annual emissions inventory report in Part B, Section V., the owner or operator must submit the date of each performance test and the results of the test (i.e., pass/fail and tested control efficiency).

II.B.2.j.(iii) By July 31 of each year (beginning 2023 and ending 2027 or upon completion of the initial performance testing schedule set forth in Table 1), 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.

II.B.4. Oil refineries are not subject to Section II.

II.B.5. Glycol natural gas dehydrators that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63 (July 1, 2022), a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard (“NSPS”) under 40 CFR Part 60 (July 1, 2022) are not subject to Section II., except for the leak detection and repair requirements in Section II.E.

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

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

II.C.1.a. (State Only) Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that has a control efficiency of at least 95% for VOCs.

II.C.1.b. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.

II.C.1.b.(i) (State Only) Control requirements of Section II.C.1.b. must be achieved in accordance with the following schedule:

II.C.1.b.(i)(A) A storage tank constructed on or after May 1, 2014, must be in compliance within ninety (90) days of the date that the storage tank commences operation.

II.C.1.b.(i)(B) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

II.C.1.b.(i)(C) A storage tank not otherwise subject to Sections II.C.1.b.(i)(A) or II.C.1.b.(i)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve-month basis after May 1, 2014, must be in compliance within sixty (60) days of discovery of the emissions increase.

II.C.1.b.(ii). Control requirements within ninety (90) days of commencement of operation.

II.C.1.b.(ii)(A) Beginning May 1, 2014, through March 1, 2020, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after commencement of operation. The air pollution control equipment must achieve a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after commencement of operation.

II.C.1.b.(ii)(B) The air pollution control equipment and any associated monitoring equipment required pursuant to Section II.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section II.C.1.b.

II.C.1.c. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to March 1, 2020.

II.C.1.c.(i) Control requirements of Section II.C.1.c. must be achieved in accordance with the following schedule

II.C.1.c.(i)(A) A storage tank constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

II.C.1.c.(i)(B) A storage tank constructed before March 1, 2020, that is not already controlled under Sections I.D. or II.C.1.b. must be in compliance by May 1, 2021.

II.C.1.c.(i)(C) A storage tank not otherwise subject to Sections II.C.1.c.(i)(A) or II.C.1.c.(i)(B) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B) must be in compliance within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.1.c.(ii) If air pollution control equipment is not installed by the applicable compliance date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C), compliance with Section II.C.1.c. may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

II.C.1.c.(iii) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.

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

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

II.C.1.d.(ii) Repealed (February 14, 2022).

II.C.1.d.(iii) Repealed (February 14, 2022).

II.C.1.d.(iv) Repealed (February 14, 2022).

II.C.1.d.(v) Repealed (February 14, 2022).

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

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

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

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

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

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

II.C.1.e. (State Only) If storage tanks or associated equipment is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor such equipment until it becomes feasible to do so.

II.C.1.e.(i) Difficult to monitor means it cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

II.C.1.e.(ii) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.C.1.e.(iii) Inaccessible to monitor means buried, insulated, or obstructed by equipment or piping that prevents access by monitoring personnel.

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

II.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation. This requirement does not apply where 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 with Section II.C.4.; or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section II.C.2.b.(ii).

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

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

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

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

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

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

II.C.2.b.(i) STEM plans must include selected control technologies, monitoring practices, operational practices, and/or other strategies; an analysis of the engineering design of the storage tank and air pollution control equipment; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument monitoring methods following the applicable schedule in Section II.C.2.b.(ii).

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

II.C.2.b.(ii)(A) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed on or after May 1, 2014, must comply with the requirements of Section II.C.2.a. by the date the storage tank commences operation. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of the date that the storage tank commences operation.

II.C.2.b.(ii)(B) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed before May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2015.

II.C.2.b.(ii)(C) A storage tank subject to Section II.C.1.c. and constructed on or after March 1, 2020, must comply with the requirements of Section II.C.2.a. by commencement of operation of the storage tank. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of commencement of operation of the storage tank.

II.C.2.b.(ii)(D) A storage tank subject to Sections II.C.1.c. and I.D.3. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

II.C.2.b.(ii)(E) A storage tank subject to Section II.C.1.c. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2021. Approved instrument monitoring method inspections of the storage tank must begin in 2021.

II.C.2.b.(ii)(F) A storage tank with uncontrolled actual emissions of VOCs equal to or greater than six (6) and less than or equal to twelve (12) tons per year must begin semi-annual approved instrument monitoring method inspections in 2020.

II.C.2.b.(ii)(G) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) or II.C.2.b.(ii)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis..

II.C.2.b.(ii)(H) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) through II.C.2.b.(ii)(F) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B), must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded the applicable threshold based on a rolling twelve-month basis.

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

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

II.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e.

II.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy(ies) are designed to minimize emissions from storage tanks and associated equipment at the facility(ies), including thief hatches and pressure relief devices.

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

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

II.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance (though recordkeeping is required if actions are required to reduce maintenance emissions 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 (February 14, 2022).

II.C.3.f. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions, including the dates and results of action(s) taken and the monitoring used to confirm the action(s) were successful.

II.C.3.g. A list of equipment associated with the storage tank that is designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.C.1.e., an explanation stating why the equipment is so designated, and the plan for monitoring such equipment.

II.C.3.h. Records of any exemption, and associated documentation, applied for under Section II.C.1.c.(iii).

II.C.4. (State Only) Storage tank measurement system requirements at well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.4.a. Applicability

II.C.4.a.(i) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after May 1, 2020, and at any facilities that are modified on or after May 1, 2020, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quantity of liquids in the storage tank(s).

II.C.4.a.(ii) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after January 1, 2021, and at any facilities that are modified on or after January 1, 2021, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quality and quantity of liquids in the storage tank(s).

II.C.4.b. Owner or operators subject to the storage tank measurement system requirements in Section II.C.4.a., must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage tank(s).

II.C.4.c. Operators may inspect, test, and/or calibrate the storage tank measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Section II.C.4.b.

II.C.4.d. The owner or operator must install signage at or near the storage tank that indicates which equipment and method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.4.e. The owner or operator must develop and implement an annual training program for employees and/or third parties conducting activities subject to Section II.C.4. that includes, at a minimum, operating procedures for each type of system.

II.C.4.f. Owner or operators must retain records for at least two (2) years and make such records available to the Division upon request, including

II.C.4.f.(i) Date of construction of the storage vessel or facility.

II.C.4.f.(ii) Description of the storage tank measurement system used to comply with Section II.C.4.a.

II.C.4.f.(iii) Date(s) of storage tank measurement system inspections, testing, and/or calibrations pursuant to Section II.C.4. c.

II.C.4.f.(iv) Manufacturer specifications regarding storage tank measurement system inspections, and/or calibrations, if followed pursuant to Section II.C.4.c.

II.C.4.f.(v) Records of the annual training program, including the date and names of persons trained.

II.C.5. (State Only) Storage tank hydrocarbon liquids loadout requirements at Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.5.a. Owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with a hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

Owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

II.C.5.a.(i) Compliance with Section II.C.5. must be achieved in accordance with the following schedule

II.C.5.a.(i)(A) Facilities constructed or modified on or after May 1, 2020, must be in compliance by commencement of operation.

II.C.5.a.(i)(B) Facilities constructed before May 1, 2020, must be in compliance by May 1, 2021.

II.C.5.a.(i)(C) Class II disposal well facilities constructed or modified on or after January 1, 2021, must be in compliance by commencement of operation.

II.C.5.a.(i)(D) Class II disposal well facilities constructed before January 1, 2021, must be in compliance by May 1, 2021.

II.C.5.a.(i)(E) Facilities not subject to Sections II.C.5.a.(i)(A) or II.C.5.a.(i)(B) that exceed the hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from loadout upon exceeding the loadout threshold.

II.C.5.a.(i)(F) Facilities not subject to Sections II.C.5.a.(i)(C) or II.C.5.a.(i)(D) that exceed the hydrocarbon liquids loadout to transport vehicles emissions threshold of greater than or equal to two (2) tons uncontrolled actual VOC emissions per year on a rolling 12-month basis must control emissions from loadout within sixty (60) days of the first day of the month after which loadout emissions exceeded the loadout threshold.

II.C.5.a.(ii) Storage tanks must operate without venting at all times during loadout.

II.C.5.a.(iii) The owner or operator must, as applicable:

II.C.5.a.(iii)(A) Install and operate the vapor collection and return equipment to collect vapors during the loadout of hydrocarbon liquids to tank compartments of outbound transport vehicles and to route the vapors to the storage tank or air pollution control equipment.

II.C.5.a.(iii)(B) Include devices to prevent the release of vapor from vapor recovery hoses not in use.

II.C.5.a.(iii)(C) Use operating procedures to ensure that hydrocarbon liquids cannot be transferred to transport vehicles unless the vapor collection and return system is in use.

II.C.5.a.(iii)(D) Operate all recovery and disposal equipment at a back-pressure less than the pressure relief valve setting of transport vehicles.

II.C.5.a.(iii)(E) The owner or operator must inspect onsite loading equipment to ensure that hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loadout. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv) Loadout observations and operator training

II.C.5.a.(iv)(A) The owner or operator must observe loadout to confirm that all storage tanks operate without venting when loadout operations are active. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv)(B) If observation of loadout is not feasible, the owner or operator must document the annual loadout frequency and the reason why observation is not feasible and inspect the facility within 24 hours after loadout to confirm that all storage tank thief hatches (or other access point to the tank) are closed and latched.

II.C.5.a.(iv)(C) The owner or operator must install signage at or near the loadout control system that indicates which loadout control method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.5.a.(iv)(D) The owner or operator must develop and implement an annual training program for employees and/or third parties conducting loadout activities subject to Section II.C.5. that includes, at a minimum, operating procedures for each type of loadout control system.

II.C.5.a.(v) Owners or operators must retain records for at least two (2) years and make such records available to the Division upon request.

II.C.5.a.(v)(A) Records of the annual facility hydrocarbon liquids loadout to transport vehicles throughput.

II.C.5.a.(v)(B) Inspections, including a description of any problems found and their resolution, required under Sections II.C.5.a.(iii) and II.C.5.a.(iv) must be documented in a log.

II.C.5.a.(v)(C) Records of the infeasibility of observation of loadout.

II.C.5.a.(v)(D) Records of the frequency of loadout.

II.C.5.a.(v)(E) Records of the annual training program, including the date and names of persons trained.

II.C.5.a.(v)(F) Records of class II disposal well facility VOC emissions from hydrocarbon liquids loadout to transport vehicles on a rolling 12-month basis.

II.C.5.a.(vi) Air pollution control equipment used to comply with this Section II.C.5. must comply with Section II.B., be inspected in accordance with Sections II.B.2.f.(ii)(A) through II.B.2.f.(ii)(D), and achieve a hydrocarbon control efficiency of 95%.

II.D. (State Only) Emission reductions from glycol natural gas dehydrators

II.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

II.D.2. The control requirement in Section II.D.1. apply where:

II.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

II.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

II.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:

II.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and

II.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.

II.D.4. The control requirement in Section II.D.3. apply where:

II.D.4.a. Uncontrolled actual emissions of VOCs from a glycol natural gas dehydrator constructed on or after May 1, 2015, are equal to or greater than two (2) tons per year. Such glycol natural gas dehydrators must be in compliance with Section II.D.3. by the date that the glycol natural gas dehydrator commences operation.

II.D.4.b. Uncontrolled actual emissions of VOCs from a single glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

II.D.4.c. For purposes of Sections II.D.3. and II.D.4.:

II.D.4.c.(i) Building Unit means a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

II.D.4.c.(ii) A Designated Outside Activity Area means an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government had established as a designated outside activity area by the COGCC; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

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

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

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

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

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

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

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

II.E.3.a.(iii) Beginning January 1, 2023, 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 quarterly 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 3.

II.E.3.d. Beginning January 1, 2023, owners or operators of natural gas compressor stations located within a disproportionately impacted community or within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.

II.E.3.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 3 – Natural Gas Compressor Station Component Inspections

Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and < 12	Quarterly
> 0 and < 50, located within a disproportionately impacted community or within 1,000 feet of an occupied area	Bimonthly
> 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 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 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 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.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 4.

II.E.4.e. Owners or operators of well production facilities must inspect components for leaks using an approved instrument monitoring method as follows, except as provided in Section II.E.4.f.

II.E.4.e.(i) Beginning January 1, 2023, for well production facilities that commenced operation before May 1, 2022, in accordance with the inspection frequencies in Table 5.

II.E.4.e.(ii) Well production facilities that commence operation on or after May 1, 2022, must be inspected at least monthly.

II.E.4.f. Alternative inspection frequency requirements.

Owners or operators of well production facilities in compliance with Sections II.E.4.f.(i) or II.E.4.f.(ii) must inspect components for leaks using an approved instrument monitoring method at least semi-annually or consistent with the inspection frequency in Table 4, whichever is more frequent, except that a well production facility with uncontrolled actual VOC emissions less than two (2) tons per year as of February 14, 2022, need only be inspected at least annually. Owners or operators must comply with all other requirements of Section II.E.

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, as appropriate.

II.E.4.f.(i)(A) Continuously tracks the pressure in the storage tank(s) and monitors 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 uses only non-emitting pneumatic controllers, installs and operates a software system providing automated operational feedback to a central control system, and does not install and operate hydrocarbon liquid storage tanks (other than a maintenance tank) or natural gas-fired reciprocating internal combustion engines.

II.E.4.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 – Well Production Facility Component Inspections				
Thresholds (per II.E.4.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
> 12 and < 20	> 12 and < 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 20	> 50	Monthly		January 1, 2015

Table 5 - Well Production Facility Component Inspections on or after January 1, 2023		
Thresholds (per II.E.4.g.)		
Well production facilities (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency
> 0 and < 2	Annual	Monthly
> 0 and < 2, located within 1,000 feet of an occupied area	Semi-annual	Monthly
> 0 and < 2, located in the 8-hour ozone control area and within a disproportionately impacted community	Semi-annual	Monthly
> 2 and < 50	Quarterly	Monthly
> 2 and < 12, located within 1,000 feet of an occupied area or within a disproportionately impacted community	Bimonthly	Monthly
> 12, located within 1,000 feet of an occupied area or within a disproportionately impacted community	Monthly	
> 20, well production facilities without storage tanks	Monthly	
> 50, well production facilities with storage tanks	Monthly	

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 February 14, 2022, for leaks identified using an approved non-quantitative instrument monitoring method or AVO at a well production facility located within a disproportionately impacted community or at a well production facility inspected pursuant to Section II.E.4.f., 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 February 14, 2022, the owner or operator must take action(s) where technically feasible to mitigate emissions from leaks placed on delay of repair within no later than 48 hours of placing a leaking component 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. 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 February 14, 2022, 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.

II.E.8.i.(iv) For leaks discovered after February 14, 2022, 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 a 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) Emission reductions from downhole well maintenance, well liquids unloading events, and well plugging activities.

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. 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, for all downhole well maintenance and well liquids unloading activities with emissions to atmosphere, owners or operators must, 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 that commence operation after January 1, 2023, to minimize the need for well liquids unloading with emissions to atmosphere 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/or flow rate of the vented natural gas.

II.G.1.c.(iv) Equalize the wellhead pressure with the production separator pressure prior to conducting unloading, swabbing, or maintenance activities, when practicable.

II.G.1.c.(v) Close wellhead vents to the atmosphere or otherwise end direct emission of natural gas to atmosphere as soon as practicable.

II.G.1.c.(vi) Minimize emissions to atmosphere from well liquids unloading and well swabbing, through the installation, use, and optimization of artificial lift, such as plunger lift with smart automation, except

II.G.1.c.(vi)(A) Artificial lift is not required where an operator demonstrates to the Division that installation and use of artificial lift is technically infeasible on a well because of the structure of the well.

II.G.1.c.(vi)(B) Smart automation is not required where an operator demonstrates to the Division that use of smart automation is technically infeasible.

II.G.1.c.(vi)(C) Artificial lift is not required on a well drilled after February 14, 2022, until that well begins requiring regular liquids unloading operations. The owner or operator must install artificial lift at such well no later than twelve months after the well commences operation.

II.G.1.c.(vi)(D) The Division can approve an alternative to artificial lift if the owner or operator demonstrates that use of artificial lift would result in an emissions increase or other environmental disbenefit.

II.G.1.d. Beginning January 1, 2023, unless exempted in Sections II.G.1.d.(i) or II.G.1.d.(ii), owners or operators must use capture and recovery techniques or install and use a control device to achieve at least 95% control of hydrocarbon emissions during well liquids unloading and well swabbing operations. Notwithstanding any provision in Section II.B. to the contrary, owners or operators may use open flares and portable combustion devices to comply with this Section II.G.1.d.

II.G.1.d.(i) Owners or operators are not required to use control devices during well swabbing operations if pressurized equipment is used such that hydrocarbons are not emitted to the atmosphere from the well swabbing operation.

II.G.1.d.(ii) Owners or operators are not required to capture or control emissions during well liquids unloading and well swabbing operations if, during the preceding rolling twelve-month period

II.G.1.d.(ii)(A) The well production facility is located within a disproportionately impacted community and the operator did not conduct more than or equal to six (6) well liquids unloading and well swabbing events with emissions to atmosphere during any rolling six-month period.

II.G.1.d.(ii)(B) The well production facility is not located within a disproportionately impacted community and did not have any single well with more than or equal or six (6) well liquids unloading and well swabbing events with emissions to atmosphere during any rolling six-month period or any well(s), in the aggregate, with more than or equal to ten (10) well liquids unloading events and well swabbing with emissions to atmosphere during any rolling six-month period.

II.G.1.d.(ii)(C) Capturing or controlling the emissions from the well liquids unloading or well swabbing event is technically infeasible, as approved by the Division.

II.G.1.d.(iii) Well liquids unloading events are not included in the calculation for purposes of Section II.G.1.d.(ii) where the need for well liquids unloading resulted from the infiltration of excess water directly caused by a nearby hydraulic fracturing event provided that the owner of the well to be unloaded provides the Division with at least 48 hours written notice (or as soon as possible prior to conducting well liquids unloading if 48 hours' notice would require an alternative or extended well liquids unloading practice that increases emissions) of the intent to begin unloading and the unloading activities are completed within thirty (30) days of commencement of those activities. The notice must include an identification of the operator that conducted the fracturing event suspected of contributing to the infiltration of water and the well API number(s) of the well that was fractured.

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, in addition to the records in Section II.G.2.b., the owner or operator must keep the following records for five (5) 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 swabbing, and well plugging event.

II.G.2.c.(ii) The type of artificial lift used to reduce emissions pursuant to Section II.G.1.c.(vi); the number of well liquids unloading and well swabbing events resulting in emissions to atmosphere; or, if applicable, documentation of the justification for not having artificial lift under Section II.G.1.c.(vi). If plunger lift is installed, the number of cycles of the plunger.

II.G.2.c.(iii) Whether the well liquids unloading or well swabbing event was controlled pursuant to Section II.G.1.d. and, if not, the justification for the exemption under Sections II.G.1.d.(i) or II.G.1.d.(ii), including all records relating to Section II.G.1.d.(iii) and records of production during the 30-day time period covered by Section II.G.1.d.(iii) and an estimate of the VOC and methane emissions during that same 30-day time period associated with the well liquids unloading or well maintenance activities.

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, well swabbing, 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, and, beginning with the annual report for calendar year 2023 whether the event was controlled.

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 with the annual report submitted June 30th of 2023 (for calendar year 2022), whether the well identified in Section II.G.3.a.(i) is equipped with artificial lift.

II.H. (State Only) Emission reductions from midstream segment pigging operations and blowdowns of piping and equipment.

II.H.1. Pigging operations and blowdowns of piping and equipment located at natural gas compressor stations and natural gas processing plants.

II.H.1.a. Consistent with the schedule for compliance in Section II.H.1.c., at natural gas compressor stations and natural gas processing plants in disproportionately impacted communities, midstream segment owners or operators must capture and recover hydrocarbon emissions from

II.H.1.a.(i) Pigging units attached to a high-pressure pigging pipeline with an outside diameter of twelve (12) inches or greater.

II.H.1.a.(ii) Pigging units with annual uncontrolled actual emissions equal to or greater than 0.5 tpy VOC or 1 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation.

II.H.1.a.(iii) Blowdowns of compressors, where total uncontrolled actual blowdown emissions from all compressors are greater than or equal to 0.75 tpy VOC or 1.5 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation. Hydrocarbons emitted during a compressor blowdown event where the physical volume of the compressor is less than fifty (50) cubic feet (cf) are not included in the emissions calculated for purposes of applicability of this Section II.H.1.a.(iii), provided the owner or operator maintains records of the dates and number of such events.

II.H.1.a.(iv) Blowdowns of all equipment and piping not covered by Sections II.H.1.a.(i) through II.H.1.a.(iii) where the physical volume between isolation valves is greater than or equal to fifty (50) cf. This requirement does not apply if the owner or operator can demonstrate that the aggregate uncontrolled actual emissions from blowdowns of all equipment and piping subject to this Section II.H.1.a.(iv) are less than 0.75 tpy VOC and 1.5 tpy methane, provided the owner or operator maintains records of the dates and number of all blowdowns including blowdowns where the physical volume between isolation valves is greater than one (1) cf but less than fifty (50) cf.

II.H.1.b. Consistent with the schedule for compliance in Section II.H.1.c., at all natural gas compressor stations and natural gas processing plants not located in a disproportionately impacted community, midstream segment owners or operators must capture and recover hydrocarbon emissions from

II.H.1.b.(i) Pigging units attached to high-pressure pigging pipelines with an outside diameter of twelve (12) inches or greater.

II.H.1.b.(ii) Pigging units with annual uncontrolled actual emissions equal to or greater than 1 tpy VOC or 2 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation.

II.H.1.b.(iii) Blowdowns of compressors, where total uncontrolled actual blowdown emissions from all compressors are greater than or equal to 1 tpy VOC or 2 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation. Hydrocarbons emitted during a compressor blowdown event where the physical volume of the compressor is less than fifty (50) cf are not included in the emissions calculated for purposes of applicability of this Section II.H.1.b.(iii), provided the owner or operator maintains records of the dates and number of such events.

II.H.1.b.(iv) Blowdowns of equipment and piping not covered by Sections II.H.1.b.(i) through II.H.1.b.(iii) where the physical volume between isolation valves is greater than or equal to fifty (50) cf. This requirement does not apply if the owner or operator can demonstrate that the aggregate uncontrolled actual emissions from blowdowns of all equipment and piping subject to this Section II.H.1.a.(iv) are less than 1 tpy VOC and 2 tpy methane, provided the owner or operator maintains records of the dates and number of all blowdowns including blowdowns where the physical volume between isolation valves is greater than one (1) cf but less than fifty (50) cf.

II.H.1.c. Schedule for compliance with Sections II.H.1.a. and II.H.1.b. Midstream segment owners or operators must be in compliance

II.H.1.c.(i) Upon commencement of operation for any natural gas compressor station or natural gas processing plant that commences operation on or after February 14, 2022.

II.H.1.c.(ii) By January 1, 2023, at no less than fifty percent (50%) of natural gas compressor stations and natural gas processing plants that commenced operation before February 14, 2022, and that are located within a disproportionately impacted community.

II.H.1.c.(iii) By June 1, 2023, at all natural gas compressor stations and natural gas processing plants that commenced operation before February 14, 2022, and that are located within a disproportionately impacted community.

II.H.1.c.(iv) By January 1, 2024, for all natural gas compressor stations and natural gas processing plants that commenced operation before February 14, 2022.

II.H.1.c.(v) Within sixty (60) days of the first day of the month after which a pigging unit in a disproportionately impacted community not subject to Sections II.H.1.a.(i) or (ii) increases hydrocarbon emissions to 0.5 tpy VOC or 1 tpy methane after the applicable compliance date in Sections II.H.1.c.(i) through II.H.1.c.(iv), on a rolling twelve-month basis.

II.H.1.c.(vi) Within sixty (60) days of the first day of the month after which a pigging unit not located in a disproportionately impacted community and not subject to Sections II.H.1.b.(i) or II.H.1.b.(ii) that increases hydrocarbon emissions to 1 tpy VOC or 2 tpy methane after the applicable compliance date in Sections II.H.1.c.(i) through II.H.1.c.(iv), on a rolling twelve-month basis.

II.H.1.c.(vii) Within sixty (60) days of the first day of the month after which blowdowns of compressors or other equipment and piping with a physical volume of the compressor or between isolation valves of equal to or greater than 50 cf located at a natural gas compressor station or natural gas processing plant located in a disproportionately impacted community not subject to Sections II.H.1.a.(iii) or II.H.1.a.(iv) increases hydrocarbon emissions to 0.75 tpy VOC or 1.5 tpy methane after the applicable compliance date in Section II.H.1.c.(i)-(iv), on a rolling twelve-month basis.

II.H.1.c.(viii) Within sixty (60) days of the first day of the month after which blowdowns of compressors or other equipment and piping with a physical volume of the compressor or between isolation valves of equal to or greater than 50 cf located at a natural gas compressor station or natural gas processing plant not located in a disproportionately impacted community not subject to Sections II.H.1.b.(iii) or II.H.1.b.(iv) increases hydrocarbon emissions to 1 tpy VOC or 2 tpy methane after the applicable compliance date in Sections II.H.1.c.(i) through II.H.1.c.(iv), on a rolling twelve-month basis.

II.H.1.c.(ix) An owner or operator may request an extension of the compliance schedules in Sections II.H.1.c.(ii) through II.H.1.c.(iv) for no more than twelve (12) months. The Division may approve such request if the owner or operator demonstrates that the extension is required to facilitate coordinated engineering and design projects to holistically address compliance with Section II.H. in order to avoid temporary solutions and emissions disbenefits, if any, that may be caused by the compliance schedules in Sections II.H.1.c.(ii) through II.H.1.c.(iv).

II.H.1.d. Midstream owners or operators must capture and recover hydrocarbon emissions from pigging units that commence operation after February 14, 2022, where the pigging unit is attached to a high-pressure pigging line.

II.H.2. Pigging operations at standalone pigging stations.

II.H.2.a. Midstream segment owners or operators must capture and recover hydrocarbon emissions from the following pigging operations at standalone pigging stations that commence operation on or after February 14, 2022.

II.H.2.a.(i) Pigging units attached to a high-pressure pigging pipeline.

II.H.2.a.(ii) Pigging units located in a disproportionately impacted community with annual uncontrolled actual emissions equal to or greater than 0.5 tpy VOC or 1 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation.

II.H.2.a.(iii) Pigging units not located in a disproportionately impacted community with annual uncontrolled actual emissions greater than or equal to 1 tpy VOC or 2 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation.

II.H.2.b. Beginning January 1, 2023, at standalone pigging stations that commenced operation before February 14, 2022, located within a disproportionately impacted community, midstream segment owners or operators must capture and recover hydrocarbon emissions from pigging operations

II.H.2.b.(i) At pigging units with annual uncontrolled actual emissions equal to or greater than 0.5 tpy VOC or 1 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation.

II.H.2.b.(ii) Where the pigging unit is attached to a high-pressure pigging pipeline with an outside diameter of twelve (12) inches or greater.

II.H.2.b.(iii) A pigging unit not subject to Section II.H.2.b.(i) as of January 1, 2023, that increases hydrocarbon emissions to 0.5 tpy VOC or 1 tpy methane must be in compliance with Section II.H.2.b, within sixty (60) days of the first day of the month after which the emissions exceeded the applicable threshold, based on a rolling twelve-month basis.

II.H.2.c. Beginning January 1, 2024, at standalone pigging stations that commenced operation before February 14, 2022, that are not in a disproportionately impacted community, midstream segment owners or operators must capture and recover hydrocarbon emissions from pigging operations

II.H.2.c.(i) At pigging units with annual uncontrolled actual emissions equal to or greater than 1 tpy VOC or 2 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation.

II.H.2.c.(ii) Where the pigging unit is attached to a high-pressure pigging pipeline with an outside diameter of twelve (12) inches or greater.

II.H.2.c.(iii) A pigging unit not subject to Section II.H.2.c.(i) as of January 1, 2024, that increases hydrocarbon emissions to 1 tpy VOC or 2 tpy methane must be in compliance with Section II.H.2.c. within sixty (60) days of the first day of the month after which the emissions exceeded the applicable threshold, based on a rolling twelve-month basis.

II.H.3. Capture and recovery requirements.

II.H.3.a. Capture and recovery requirements apply during normal operation.

II.H.3.b. Capture and recovery requirements do not apply during planned emergency system shutdown testing operations.

II.H.3.c. Capture and recovery is not required pursuant to Sections II.H.1.a.(iv) or II.H.1.b.(iv) for blowdowns of storage vessels; pressure vessels; or process vessels such as surge vessels, bottom receivers, or knockout vessels, that operate at a pressure less than twenty (20) psig.

II.H.3.d. Residual emission from depressurization of the blowdown volume remaining after capture and recovery techniques have been implemented are considered in compliance with the capture and recovery requirements of Sections II.H.1. and II.H.2.

II.H.3.e. Where a natural gas compressor station or natural gas processing plant is connected to an electrical grid, capture and recovery techniques must be powered by non-emitting equipment, where technically and economically feasible. If technically or economically infeasible, the midstream owner or operator will maintain a record of the analysis undertaken at the time the pigging unit or piping and equipment became subject to Section II.H.1.

II.H.3.f. If capture and recovery of the hydrocarbon emissions emitted is not feasible, the owner or operator may request Division approval to use a control device to comply with Sections II.H.1. or II.H.2. The Division may approve the use of open flares to control hydrocarbon emissions from pigging operations and blowdowns under Sections II.H.1. or II.H.2. Any Division approval will include appropriate operating and maintenance requirements for the control device utilized.

II.H.3.f.(i) Pigging operations and blowdowns that are minimized through the use of a control device or closed-vent system as of February 14, 2022, or for which a permit application is pending to require the use of a control device or closed-vent system, as of December 31, 2021, do not need further Division approval to continue use of the control device or closed-vent system for purposes of Sections II.H.1. or II.H.2. The owner or operator utilizing control devices under this Section II.H.3.f.(i) must notify the Division by March 31, 2022, that control devices will be used to comply with Sections II.H.1. or II.H.2.

II.H.3.g. Midstream owners or operators must design and operate natural gas compressor stations, natural gas processing plants, and standalone pigging stations that commence operation on or after January 1, 2023, to maximize the capture and recovery of hydrocarbon emissions from pigging operations and equipment and piping routinely blown down based on technologies and capabilities that are technically and economically feasible at the time of facility development. Midstream owners or operators must maintain a record of the analysis undertaken at the time of facility development pursuant to this section for the life of the facility.

II.H.4. Beginning January 1, 2023, midstream segment owners or operators must utilize best practices to minimize emissions from pigging operations and blowdowns during normal operations, including all stand-alone pigging stations and midstream pipelines not located within the boundaries of a natural gas compressor station or natural gas processing plant, including

II.H.4.a. Keeping pipeline access openings to the atmosphere on 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.4.b. In the 8-hour ozone control area and northern Weld County, utilizing a liquids management system to reduce the accumulation of liquids in the pigging unit. A liquids management system to include, but is not limited to, use of a pig ramp, process drain, pig receiver on an incline, or a closed liquids containment system.

II.H.4.c. Where feasible for pipeline blowdowns other than for pigging operations, 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.4.c.(i) For purposes of Section II.H.4.c., feasibility requires that a low-pressure line be nearby, be owned or operated by the same midstream owner or operator, and be on contiguous property owned or operated by the midstream owner or operator. Feasibility here also means that the action is economically feasible.

II.H.4.c.(ii) The Division can approve alternatives to the best practices in Section II.H.4.c. where the owner or operator demonstrates that the alternatives will achieve equivalent or better emission reductions.

II.H.4.d. Creating or updating operating and maintenance plans to provide for the use, where practicable, of the following best practices. The operating and maintenance plan must describe the situations and circumstances where use of the best practice is, and is not, practicable, and must identify the documentation that will enable the Division to confirm whether the best practice was used consistently with the operating and maintenance plan.

II.H.4.d.(i) Using short pig barrels, where it reduces the gas volume for potential release.

II.H.4.d.(ii) 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.4.d.(iii) Minimizing the volume that must be released. For example, adding stops to isolate a smaller section of a pipeline to reduce the length of pipe that must be vented.

II.H.4.d.(iv) Using inert gases and pigs to perform pipeline purges.

II.H.4.d.(v) Hot tapping to make new connections to pipelines.

II.H.4.d.(vi) Coordinating operational repairs and routine maintenance to minimize the number of emissions events and volume.

II.H.5. Recordkeeping. 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.H.5.a. General records.

II.H.5.a.(i) If subject to Sections II.H.1.a. or II.H.1.b., documentation of the methods used to comply with Sections II.H.1.a. or II.H.1.b. If exempt from Sections II.H.1.a. or II.H.1.b., documentation supporting the exemption.

II.H.5.a.(ii) If control equipment is used to comply with Sections II.H.1.a., II.H.1.b., or II.H.1.d., documentation of operating and maintenance activities, and the date and duration of any control equipment downtime during active pigging operations or blowdowns.

II.H.5.a.(iii) Documentation of best practices employed pursuant to Section II.H.4., including any operating and maintenance plans created, updated, or revised under Section II.H.4.d. and the records documenting compliance therewith.

II.H.5.b. Records of pigging operations.

II.H.5.b.(i) The number of pigging events, whether or not subject to capture or control, including the locations of the pigging event, associated pigging units and facility(ies) (including AIRS ID, if applicable); date and time; diameter and normal operating pressure of pigging pipeline; pressure of pigging unit immediately before and after pigging operations (or after capture and recovery if applicable); volume of gas recovered and released; and type and volume of liquid removed from the pigging unit after pigging operations, if any.

II.H.5.b.(ii) The monthly and annual VOC and methane emissions associated with the pigging operations, in accordance with Division-approved calculation methodology, including the VOC and methane weight percent composition of the fluid transported by the pigging pipeline at normal pipeline operating conditions used in the calculations and the date and location of the sample, or other justification of representative composition data.

II.H.5.c. Records of blowdowns.

II.H.5.c.(i) The location (by equipment, facility, and AIRS ID, or by equipment and coordinates if no AIRS ID), date and time of blowdown event.

II.H.5.c.(ii) The monthly and annual VOC and methane emissions from blowdowns, aggregated by equipment blown-down.

II.H.5.c.(iii) The date, location, identification of equipment or piping and number of blowdown events (other than pigging operations), including identification of whether the volume between isolation valves is less than 50 cf.

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). In addition,

II.I.1.a. The owner or operator must complete repair of components placed on delay of repair within two (2) years or the applicable timeline provided in 40 CFR Part 60, Subpart OOOO (August 16, 2012) or 40 CFR Part 60, Subpart OOOOa (June 3, 2016), whichever is earlier.

II.I.1.b. The owner or operator must take action(s) to mitigate emissions from leaks placed on delay of repair where technically feasible.

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

III.A. Applicability

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

III.B. Definitions

III.B.1. “Affected Operations” means pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B.2. “Continuous Bleed” means a continuous bleed rate of natural gas from a pneumatic controller that is designed to bleed natural gas continuously.

III.B.3. “Custody Transfer” means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

III.B.4. (State Only) “Enhanced Response” means to return a pneumatic controller to proper operation and includes but is not limited to, cleaning, adjusting, and repairing leaking gaskets, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

III.B.5. “High-Bleed Pneumatic Controller” means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

III.B.6. (State Only) “Intermittent pneumatic controller” means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release natural gas to the atmosphere as part of the actuation cycle.

III.B.7. “Low-Bleed Pneumatic controller” means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

III.B.8. “Natural Gas Processing Plant” means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

III.B.9. “No-Bleed Pneumatic Controller” means any pneumatic controller that is not using hydrocarbon gas as the valve’s actuating gas.

III.B.10. “Non-emitting Controller” means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.

III.B.11. “Pneumatic Controller” means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

III.B.12. “Routed Pneumatic Controller” means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.

III.B.13. "Self-contained Pneumatic Controller" means a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.

III.B.14. "Wellhead" means the piping, casing, tubing and connected valves supporting or controlling the operation of an oil and/or natural gas well. The wellhead does not include other process equipment at the wellhead site.

III.C. Emission Reduction Requirements

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

III.C.1. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area or northern Weld County and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.C.1.a. All pneumatic controllers located in the 8-Hour Ozone Control Area and placed in service on or after February 1, 2009, must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.1.f.

III.C.1.b. All high-bleed pneumatic controllers located in the 8-Hour Ozone Control Area and in service prior to February 1, 2009 shall be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section III.C.1.f.

III.C.1.c. All pneumatic controllers located in northern Weld County and placed in service on or after February 14, 2023, and not already subject to Section III.C.3.a., must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.1.f.

III.C.1.d. All high-bleed pneumatic controllers located in northern Weld County in service prior to February 14, 2023, and not already subject to Section III.C.3.b. must be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2023, unless allowed pursuant to Section III.C.1.f.

III.C.1.e. Except as provided in Section III.C.1.e.(iv), the following facilities must use only non-emitting controllers:

III.C.1.e.(i) Well production facilities that commence operations on or after February 14, 2023;

III.C.1.e.(ii) Well production facilities that receive production from a well that first begins production or is recompleted or refractured on or after February 14, 2023; and

III.C.1.e.(iii) Natural gas compressor stations that commence operations or increase compression horsepower on or after February 14, 2023.

III.C.1.e.(iv) 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.1.e.

III.C.1.e.(iv)(A) Pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas. Owners or operators must submit justification to the Division for the emitting pneumatic controller(s) to be installed forty-five (45) days prior to installation.

III.C.1.e.(iv)(B) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.

III.C.1.e.(iv)(C) Pneumatic controllers on temporary or portable equipment that is in use and onsite for sixty (60) days or less. This does not apply to use on temporary or portable equipment used to temporarily increase throughput capacity of a facility. Owners or operators must submit justification to the Division for continued use beyond sixty (60) days at least fourteen (14) days before the 60-day period expires.

III.C.1.e.(iv)(D) Pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices or for artificial lift control located on a wellhead that is greater than one quarter mile from the associated well production facility or that is not located on the same surface disturbance as the associated production facility.

III.C.1.e.(iv)(E) Any pneumatic controller that emits natural gas pursuant to Sections III.C.1.e.(iv)(A) through (D) must be tagged, which will indicate that the controller may emit natural gas.

III.C.1.f. All high-bleed pneumatic controllers that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.1.f.(i) For high-bleed pneumatic controllers located in the 8-Hour Ozone Control Area and in service prior to February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.

III.C.1.f.(ii) For high-bleed pneumatic controllers located in the 8-Hour Ozone Control Area and placed in service on or after February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.1.f.(iii) For high-bleed pneumatic controllers located in northern Weld County in service prior to February 14, 2023, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2023.

III.C.1.f.(iv) For high-bleed pneumatic controllers located in northern Weld County and placed in service on or after February 14, 2023, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.2. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area or northern Weld County and located at a natural gas processing plant:

III.C.2.a. All pneumatic controllers in the 8-Hour Ozone Control Area placed in service on or after January 1, 2018, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.2.e.

III.C.2.b. All pneumatic controllers in the 8-Hour Ozone Control Area with a bleed rate greater than zero in service prior to January 1, 2018, must be replaced or retrofit such that the pneumatic controller has a natural gas bleed rate of zero by May 1, 2018, unless allowed pursuant to Section III.C.2.e.

III.C.2.c. All pneumatic controllers located in northern Weld County and placed in service on or after February 14, 2023, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.2.e.

III.C.2.d. All pneumatic controllers located in northern Weld County with a bleed rate greater than zero in service prior to February 14, 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.2.e.

III.C.2.e. All pneumatic controllers with a natural gas bleed rate greater than zero that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.2.e.(i) For pneumatic controllers in the 8-Hour Ozone Control Area with a natural gas bleed rate greater than zero in service prior to January 1, 2018, the owner or operator must submit justification for pneumatic controllers to remain in service due to safety and /or process purposes by May 1, 2018.

III.C.2.e.(ii) For pneumatic controllers in the 8-Hour Ozone Control Area with a natural gas bleed rate greater than zero placed in service on or after January 1, 2018, the owner or operator must submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.2.e.(iii) For pneumatic controllers located in northern Weld County with a natural gas bleed rate greater than zero in service prior to February 14, 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.2.e.(iv) For pneumatic controllers located in northern Weld County with a natural gas bleed rate greater than zero placed in service on or after February 14, 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.

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, 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).

III.C.3.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, must be replaced or retrofitted by May 1, 2015, such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.3.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015.

III.C.3.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes thirty (30) days prior to installation.

III.C.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.

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

III.C.4.a. Except as provided in Section III.C.4.e.(i), the following facilities must use only non-emitting controllers:

III.C.4.a.(i) Well production facilities that commence operations on or after May 1, 2021;

III.C.4.a.(ii) Well production facilities that receive production from a well that first begins production or is recompleted or refractured on or after May 1, 2021; and

III.C.4.a.(iii) Natural gas compressor stations that commence operations or increase compression horsepower on or after May 1, 2021.

III.C.4.b. Each well production facility and natural gas compressor station with non-emitting controllers used to satisfy the requirements of Sections III.C.4.a.(i) through III.C.4.a.(iii) must contain on-site signage indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4. This Section III.C.4.b does not apply to operator’s subject to Section III.C.4.d.(vi).

III.C.4.c. Company-Wide Non-Emitting Controller Program for Well Production Facilities That Commenced Operation Before May 1, 2021

III.C.4.c.(i) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 1.

III.C.4.c.(ii) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operations before May 1, 2021, must:

III.C.4.c.(ii)(A) Determine Historic Facility Production for each existing well production facility that commenced operation before May 1, 2021.

III.C.4.c.(ii)(A)(1) Historic Facility Production at each existing well production facility which first began production during 2018 or earlier must be based on total liquids production (summing total barrels of oil and water produced through the well production facility) for the calendar year 2019.

III.C.4.c.(ii)(A)(2) Notwithstanding Section III.C.4.c.(ii)(A)(1), for any well production facility to which a well first began production during 2019, 2020 or by May 1, 2021, historic facility production must be based on the production for the first twelve (12) months beginning with the date of first production of the latest well to begin production prior to May 1, 2021.

III.C.4.c.(ii)(A)(3) Notwithstanding Sections III.C.4.c.(ii)(A)(1) and (2), for any well production facility to which a well first began production during 2019, 2020, or by May 1, 2021, if twelve (12) months since date of first production of the latest well to begin production has not passed as of May 1, 2021, then the owner or operator must use an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

III.C.4.c.(ii)(B) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all existing well production facilities that commenced operation before May 1, 2021.

III.C.4.c.(ii)(C) Determine the percentage of total liquids production for each existing facility (the Facility Percent Production) by dividing the Historic Facility Production for that facility by the Total Historic Production.

III.C.4.c.(ii)(D) Determine the Historic Non-Emitting Facility Percent Production.

III.C.4.c.(ii)(D)(1) If the well production facility, including all wellheads flowing to the well production facility, uses only non-emitting controllers, then the Facility Percent Production should be designated as Historic Non-Emitting Facility Percent Production.

III.C.4.c.(ii)(D)(2) In making the determination in Section III.C.4.c.(ii)(D)(1), pneumatic controllers that meet the conditions in Section III.C.4.e.(i) need not be considered.

III.C.4.c.(ii)(E) Determine the Total Historic Non-Emitting Facility Percent Production percentage by summing the Historic Non-Emitting Facility Percent Production for all well production facilities that commenced operation prior to May 1, 2021. The Total Historic Non-Emitting Facility Percent Production determines an owner or operators' May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production, as set forth in Table 1.

III.C.4.c.(iii) Owners or operators must demonstrate compliance with Table 1's May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production through any combination of (1) retrofitting well production facilities to utilize non-emitting controllers or (2) plugging and abandoning an existing well production facility.

III.C.4.c.(iv) An owner or operator that demonstrates that its total statewide oil and natural gas production averages 15 barrels of oil equivalent or less per day per well is not subject to the requirements of Sections III.C.4.c.(i) through (iii). To calculate average statewide oil and natural gas production per day per well, an owner or operator must sum all oil and natural gas production for calendar year 2019 in barrels of oil equivalent, divide by three hundred and sixty-five, and divide by the number of wells the owner or operator operated statewide that produced hydrocarbons in 2019.

III.C.4.c.(v) If a well production facility for which production was included in a calculation of achieving a Total Required Non-Emitting Facility Percent Production target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the well production facility to show compliance with Table 1, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgment or certification within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the well production facility to show compliance with Table 1.

In each submission of the updated Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan, the owner or operator will provide the date (month and year) when a well production facility was transferred since the last submission and whether or not the well production facility contributed or will contribute towards achieving the Total Required Non-Emitting Facility Percent Production. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.c.(vi) For each facility designated as contributing to Historic Non-Emitting Facility Percent Production, the owner or operator will place signage on-site by October 1, 2021 indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4.c.

TABLE 1*—Well Production Facilities					
Total Historic Non-Emitting Facility Percent Production	**May 1, 2022 Additional Required Non-Emitting Facility Percent Production**	**May 1, 2022 Maximum Required Non-Emitting Facility Percent Production**	**May 1, 2023 Additional Required Non-Emitting Facility Percent Production**	**May 1, 2023 Maximum Required Non-Emitting Facility Percent Production**	**Total Additional Required Non-Emitting Facility Percent Production By May 1 2023**
> 75 %	+5%	90%	+10%	96.5%	+15%
> 60-75 %	+5%	80%	+10%	90%	+15%
> 40-60 %	+10%	65%	+15%	75%	+25%
> 20-40 %	+15%	50%	+20%	65%	+35%
0-20 %	+15%	35%	+25%	55%	+40%

* Table 1 establishes minimum increases in the percentage of liquids produced (based on historic non-emitting controller use) from non-emitting facilities. Owners or operators do not need to go beyond the maximum required percentages set forth in Table 1, although they may choose to do so.

III.C.4.d. Company-Wide Non-Emitting Controller Compliance Program for Natural Gas Compressor Stations that Commenced Operation Before May 1, 2021.

III.C.4.d.(i) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 2.

III.C.4.d.(ii) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must:

III.C.4.d.(ii)(A) Determine Total Controller Count for all controllers at all of the owner or operator's natural gas compressor stations that commenced operation before May 1, 2021. The Total Controller Count must include all pneumatic controllers and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.d.(ii)(B) Determine which controllers in the Total Controller Count are non-emitting and sum the total number of non-emitting controllers and designate those as Total Historic Non-Emitting Controllers.

III.C.4.d.(ii)(C) Determine the Total Historic Non-Emitting Percent Controllers by dividing the Total Historic Non-Emitting Controller Count by the Total Controller Count.

III.C.4.d.(iii) Owners or operators must demonstrate compliance with Table 2's May 1, 2022 and May 1, 2023 Additional Required Percentage of Non-Emitting Controllers through any combination of (1) retrofitting controllers at natural gas compressor stations to utilize non-emitting controllers or (2) permanently removing natural gas compressor stations from service.

III.C.4.d.(iv) Pneumatic controllers that emit natural gas to atmosphere at natural gas compressor stations with non-emitting controllers must be tagged, which will indicate that the controller may emit natural gas. The tags must differentiate between pneumatic controllers that are exempt under Sections III.C.4.e.(i)(A) through (C) and pneumatic controllers that emit natural gas to the atmosphere under the company-wide plan. Tagging pursuant to this Section III.C.4.d.(iv) must occur by May 1, 2022.

III.C.4.d.(v) If a natural gas compressor station for which the number of pneumatic controllers located at such compressor station was included in a calculation of achieving a Total Required Non-Emitting Percent Controllers target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgement or certification, within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2.

In each submission of the updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan, the owner or operator will provide the date (month and year) when the natural gas compressor station was transferred since the last submission and whether or not the compressor station contributed or will contribute towards achieving the Total Required Non-Emitting Percent Controllers. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Compressor Station Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Compressor Station Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.d.(vi) This section applies to owners or operators of natural gas compressor stations where all the owner or operator’s active, operating natural gas compressor stations use only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers).

III.C.4.d.(vi)(A) No later than September 1, 2021, such owners or operators may file a one-time notification with the Division in lieu of the requirements in Sections III.C.4.d.(i) through (iii) that:

III.C.4.d.(vi)(A)(1) Lists each active, operating natural gas compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that, based on information and belief formed after reasonable inquiry, each of its active, operating natural gas compressor stations uses only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers); and

III.C.4.d.(vi)(A)(2) Lists each inactive, non-operating compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that after May 1, 2021, such compressor stations have not and subsequently will not operate with pneumatic controllers that emit natural gas to the atmosphere, except pneumatic controllers that qualify for exclusions set forth in subject to Sections III.C.4.e.(i)(A) through (C).

III.C.4.d.(vi)(B) If applicable, the notifications submitted under this section must list any pneumatic controllers that qualify for exclusions pursuant to Sections III.C.4.e.(i)(A) through (C) and identify the specific exemption applicable to each such pneumatic controller. Operators must tag any controller qualifying for the exclusions in Sections III.C.4.e.(i)(A) through (C) by October 1, 2021.

III.C.4.d.(vi)(C) The owner or operator must maintain a copy of the one-time notification required by Section III.C.4.d.(vi)(A) for five years.

TABLE 2* – Natural Gas Compressor Stations

Total Historic Percentage of Non-Emitting Controllers	May 1, 2022 Additional Required Percentage of Non-Emitting Controllers	May 1, 2022 Maximum Required Percentage of Non-Emitting Controllers	May 1, 2023 Additional Required Percentage of Non-Emitting Controllers	May 1, 2023 Maximum Required Percentage of Non-Emitting Controllers	Total Additional Required Percentage of Non-Emitting Controllers By May 1, 2023
> 75 %	+10%	90%	+15%	100%	+25%
>60-75 %	+10%	85%	+20%	92%	+30%
>40-60 %	+10%	70%	+25%	75%	+35%
>20-40 %	+15%	50%	+25%	65%	+40%
0-20 %	+20%	35%	+25%	60%	+45%

* Table 2 establishes minimum additional percentages of non-emitting controllers required by May 1, 2022 and May 1, 2023 based on a company's historic percentage of non-emitting controllers. Owners and operators need not go beyond the maximum required percentages specified in Table 2, although they may choose to do so.

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

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

III.C.4.e.(i)(A) Pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.

III.C.4.e.(i)(A)(1) Owners or operators that seek to rely on this exemption for facilities listed in Sections III.C.4.a.(i) through (iii) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to installation of emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(A)(2) Owners or operators that seek to rely on this exemption to maintain emitting controllers at facilities that are retrofit to meet requirements of Section III.C.4.c.(i) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(B) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.

III.C.4.e.(i)(C) Pneumatic controllers that emit natural gas located on temporary or portable equipment meeting the requirements of this Section III.C.4.e.(i)(C).

III.C.4.e.(i)(C)(1) Upon notice to the Division on a form developed by the Division, pneumatic controllers that emit natural gas other than those covered by Section III.C.4.e.(i)(B) located on temporary or portable equipment that is in use and onsite for sixty (60) days or less. However, this exemption for temporary or portable equipment does not apply to pneumatic controllers that emit natural gas used on temporary or portable equipment to temporarily increase throughput capacity of a facility.

III.C.4.e.(i)(C)(2) An owner or operator must obtain written approval from the Division for continued use beyond 60 days of pneumatic controllers that emit natural gas under Section III.C.4.e.(i)(C). The owner or operator must submit the request for an extension to the Division at least fourteen (14) days before the 60-day period expires. If the Division does not respond to the request before the 60-day period expires, the request will be deemed approved until such time as the Division may determine that the extension should be denied.

III.C.4.e.(i)(C)(2)(a) To request such an exemption, the owner or operator must submit a plan for Division approval which (1) identifies the temporary or portable equipment and number and type of pneumatic controllers that emit natural gas, (2) identifies how long the owner or operator plans to keep the equipment on site, (3) explains the need for an extension, and (4) other information as reasonably required by the Division.

III.C.4.e.(i)(C)(2)(b) In explaining the need for an extension, the operator must clearly identify the basis for extension; the anticipated schedule for use of the temporary or portable equipment; and the steps taken to minimize the length of the requested extension.

III.C.4.e.(i)(C)(3) The operator must inspect the pneumatic controllers using approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the associated well production facility or compressor station, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9.

III.C.4.e.(i)(D) Pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices 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.

III.C.4.e.(i)(D)(1) Owners or operators who seek to use a pneumatic controller at a qualifying wellhead at a facility listed in Sections III.C.4.a.(i) or (ii) that is not used as an emergency shutdown device or for artificial lift control must submit a justification for the use of such a pneumatic controller to the Division for approval forty-five (45) days prior to installation of the emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(D)(2) Owners or operators that seek to rely on this exemption to exclude emitting pneumatic controllers at a qualifying wellhead that are not used as an emergency shutdown device or for artificial lift control when determining their Total Historic Non-Emitting

Facility Percent Production pursuant to Section III.C.4.c.(ii) must submit a justification to the Division for approval no later than July 1, 2021. If the Division does not respond to the justification by August 15, 2021, the justification will be deemed approved.

III.C.4.e.(i)(D)(3) Operators that utilize the exemption in Section III.C.4.e.(i)(D) must identify leaks from components using an approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the well production facility to which the well flows as set forth in Table 3 of Section II.E.4, or on a frequency no less than one time per year, whichever is greater, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9. For well production facilities that commenced operation before May 1, 2021 with wellheads utilizing this exemption, the requirement in this Section III.C.4.e.(i)(D)(3) must begin May 1, 2022.

III.C.4.e.(i)(D)(3)(a) An owner or operator that cannot reasonably access the wellhead site to conduct a monthly AIMM or AVO inspection due to circumstances beyond its control (including but not limited to the presence of crops, wildlife restrictions, or severe weather conditions) shall conduct an AVO or AIMM inspection, as applicable, within 14 days of the condition preventing inspection being resolved. Owners or operators that rely on this Section III.C.4.e.(i)(D)(3)(a) must maintain records pursuant to Section III.C.4.g.(vii) and report pursuant Section III.C.4.g.(viii).

III.C.4.e.(i)(D)(3)(b) Operators may use drone-mounted infra-red cameras that ensure line of sight and appropriate distance from the drone to all wellhead equipment and components to conduct the inspections required under Section III.C.4.e.(i)(D)(3). Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request.

III.C.4.e.(i)(D)(4) If a wellhead has on-site electrical grid power to operate an electric controller, then operators may not utilize the exemption in Section III.C.4.e.(i)(D) for any pneumatic controller at the wellhead for which it is technically feasible to utilize an electric controller.

III.C.4.e.(i)(D)(5) Operators may not utilize the exemption in Section III.C.4.e.(i)(D) where equipment with pneumatic controllers other than the wellhead is located at the wellhead site.

III.C.4.e.(ii) By October 1, 2021, each pneumatic controller at a well production facility that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) must be tagged, which will indicate that the controller may emit natural gas.

III.C.4.e.(iii) By October 1, 2021, each pneumatic controller at a natural gas compressor station that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (C) must be tagged, which will indicate that the controller may emit natural gas.

III.C.4.f. Company-Wide Well Production Facility and Natural Gas Compressor Station Reporting Requirements.

III.C.4.f.(i) Owners and operators of well production facilities subject to Sections III.C.4.c.(i) through (iii) must submit a Company-Wide Well Production Facility Pneumatic Controller Compliance Plan to the Division on the Division-approved form by September 1, 2021, and include all of the following elements:

III.C.4.f.(i)(A) A list of existing well production facilities as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(i)(B) The following for each well production facility:

III.C.4.f.(i)(B)(1) Historic Facility Production.

III.C.4.f.(i)(B)(2) Facility Percent Production.

III.C.4.f.(i)(B)(3) Historic Non-Emitting Facility Percent Production.

III.C.4.f.(i)(B)(4) The API number for each producing well included in the Total Historic Facility Production.

III.C.4.f.(i)(C) The following company-wide information:

III.C.4.f.(i)(C)(1) Total Historic Production.

III.C.4.f.(i)(C)(2) Total Historic Non-Emitting Facility Percent Production, including a list of facilities already using non-emitting controllers as determined in Section III.C.4.c.(ii)(E).

III.C.4.f.(i)(C)(3) Total Required Non-Emitting Facility Percent Production.

III.C.4.f.(i)(D) An indication of which and in what year well production facilities are expected to be retrofit with non-emitting controllers, or plugged and abandoned, to meet the required Additional Non-Emitting Facility Percent Production for each year listed in Table 1.

III.C.4.f.(ii) Owners or operators will submit an updated Company-Wide Facility Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 1, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Facility Percent Production in a previous year's plan. The updated plan will include all of the following elements:

III.C.4.f.(ii)(A) All elements set forth in Sections III.C.4.f.(i)(A) through (C).

III.C.4.f.(ii)(B) The date (month and year) that any well production facilities were retrofit or plugged and abandoned since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(i)(D).

III.C.4.f.(ii)(C) An update of information set forth in Section III.C.4.f.(i)(D) if the Total Required Non-Emitting Facility Percent Production required by Table 1 has not been met.

III.C.4.f.(ii)(D) For each submission, the owner or operator must list each existing well production facility that is utilizing non-emitting controllers and provide a demonstration that the required Additional Non-Emitting Facility Percent Production for the relevant year has been met.

III.C.4.f.(ii)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Facility Percent Production has been met.

III.C.4.f.(iii) Owners and operators of natural gas compressor stations subject to Sections III.C.4.d.(i) through (iii) must submit a Company-Wide Compressor Station Pneumatic Controller Compliance Plan to the Division on a Division-approved form by September 1, 2021, and include all of the following elements:

III.C.4.f.(iii)(A) A listing of existing natural gas compressor stations as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(iii)(B) The following company-wide information:

III.C.4.f.(iii)(B)(1) Total Controller Count, including a list of each pneumatic controller and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.f.(iii)(B)(2) Total Historic Non-Emitting Controllers, including an indication as to which controllers are already non-emitting.

III.C.4.f.(iii)(B)(3) Total Required Non-Emitting Facility Percent Controllers.

III.C.4.f.(iii)(C) An indication of which and in what year controllers are expected to be retrofit with non-emitting controllers or removed from service (as applicable) to meet the required Additional Non-Emitting Percent Controllers for each year listed in Table 2.

III.C.4.f.(iv) Owners or operators will submit an updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 2, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Percent Controllers in a previous year's plan. The updated plan will include all of the following elements:

III.C.4.f.(iv)(A) All elements set forth in Sections III.C.4.f.(iii)(A) through (B).

III.C.4.f.(iv)(B) The date (month and year) that any controllers at natural gas compressor stations were retrofit or removed from service since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(iii)(C).

III.C.4.f.(iv)(C) The information set forth in Section III.C.4.f.(iii)(C) if the Total Required Non-Emitting Percent Controllers required by Table 2 has not been met.

III.C.4.f.(iv)(D) For each submission, the owner or operator must list total controllers and total non-emitting controllers at existing natural gas compressor stations and provide a demonstration that the required Additional Non-Emitting Percent Controllers for the relevant year has been met.

III.C.4.f.(iv)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Percent Controller has been met.

III.C.4.g. Recordkeeping and Reporting Requirements. The records in Sections III.C.4.g.(i) through (vii) must be kept for a period of five years and made available to the Division upon request.

III.C.4.g.(i) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date natural gas compressor station pneumatic controllers were retrofit or is taken out of service.

III.C.4.g.(ii) If claiming an exemption under Sections III.C.4.e.(i)(A) through III.C.4.e.(i)(D), records for each pneumatic controller demonstrating that the exemption applies.

III.C.4.g.(iii) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans required to be submitted by Sections III.C.4.f.(i) through III.C.4.f.(iv).

III.C.4.g.(iv) For any owner or operator utilizing the provision in Section III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies for that provision.

III.C.4.g.(v) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

III.C.4.g.(vi) Records required to be submitted to the Division pursuant to Sections III.C.4.c.(v) and III.C.4.d.(v).

III.C.4.g.(vii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) must maintain: (1) the date of the AIMM or AVO inspection at the production facility to which the well flows, (2) the date of the AIMM or AVO inspection of the wellhead site once the conditions preventing inspection has been resolved, and (3) records demonstrating the circumstances that prevented the wellhead site from being inspected.

III.C.4.g.(viii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) shall report annually by May 31 of each year, on a form approved by the Division, the number of wellhead sites for which the AIMM inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), the number of wellhead sites for which the AVO inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), and the total number of wellhead sites where inspections were delayed pursuant to Section III.C.4.e.(i)(D)(3)(a) for (1) 30 days or less, (2) greater than 30 days but less than or equal to 90 days, and (3) greater than 90 days.

III.D. Monitoring

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

III.D.1. In the 8-Hour Ozone Control Area or northern Weld County and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.D.1.a. Effective May 1, 2009, or February 14, 2023, if located in northern Weld County, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.1.b. Effective May 1, 2009, or February 14, 2023, if located in northern Weld County, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band, eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller’s natural gas emissions are minimized.

III.D.2. In the 8-Hour Ozone Control Area or northern Weld County and located at a natural gas processing plant:

III.D.2.a. Effective May 1, 2018, or March 1, 2023, if located in northern Weld County, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.2.b. Effective May 1, 2018, or March 1, 2023, if located in northern Weld County, the owner or operator must inspect each pneumatic controller with a natural gas bleed rate greater than zero on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

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

III.D.3.a. Effective May 1, 2015, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.3.b. Effective May 1, 2015, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.4. (State Only) Located at a natural gas processing plant 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.

III.E. Recordkeeping

III.E.1. In the 8-Hour Ozone Control Area or northern Weld County:

III.E.1.a. Continuous bleed, natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.E.1.a.(i) By January 1, 2019, or January 1, 2024, if located in northern Weld County, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, or January 1, 2024, if located in northern Weld County, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.

III.E.1.a.(ii) Beginning January 1, 2018, or January 1, 2024, if located in northern Weld County, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, or January 1, 2024, if located in northern Weld County, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour. Owners or operators must use this information to update the estimate required in Section III.E.1.a.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.) (i.e., for northern Weld County, January 1, 2027, January 1, 2030, etc.).

III.E.1.b. Continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant:

III.E.1.b.(i) By January 1, 2019, or January 1, 2024, if located in northern Weld County, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, or January 1, 2024, if located in northern Weld County, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero.

III.E.1.b.(ii) Beginning January 1, 2018, or January 1, 2024, if located in northern Weld County, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, or January 1, 2024, if located in northern Weld County, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero. Owners or operators must use this information to update the estimate required in Section III.E.1.b.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.) (i.e., for northern Weld County, January 1, 2027, January 1, 2030, etc.).

III.E.1.c. Records must be maintained for a minimum of five years and made available to the Division upon request.

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

III.E.2.a. The owner or operator must maintain a log of the total number of pneumatic controllers and their associated controller numbers per facility, the total number of pneumatic controllers per company and the associated justification that the pneumatic controllers must be used pursuant to Sections III.C.1.f. and III.C.2.e. (State Only: and in Section III.C.3.c.). The log shall be updated on a monthly basis.

III.E.2.b. The owner or operator must maintain a log of necessary maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

III.E.2.c. Records of maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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

III.F.1. General Requirements

III.F.1.a. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.1.b. Beginning May 1, 2020, owners or operators of natural gas-driven pneumatic controllers state-wide must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.2. Pneumatic controller inspection

III.F.2.a. Beginning June 30, 2018, through calendar year 2019, owners or operators of natural gas-driven pneumatic controllers at well production facilities in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.a.(i) Annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total.

III.F.2.a.(ii) Semi-annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.a.(iii) Quarterly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.b.(i) Annually at well production facilities in the 8-Hour Ozone Control Area with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than two (2) tons per year, based on a rolling twelve-month total.

III.F.2.b.(ii) Semi-annually at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than or equal to two (2) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.b.(iii) Quarterly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b.(iv) Monthly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.c. Beginning calendar year 2023, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at the same frequency that the owner or operator inspects components for leaks pursuant to Sections II.E.4.e. or II.E.4.f.

III.F.2.d. For purposes of Sections III.F.2.a. through III.F.2.c., the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

III.F.2.e. Beginning June 30, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.e.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.f. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations outside the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.f.(i) Semi-annually at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.f.(ii) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than twelve (12) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.f.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.g. Beginning calendar year 2023, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.g.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.g.(ii) Bimonthly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total, and located within a disproportionately impacted community or within 1,000 feet of an occupied area.

III.F.2.g.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

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

III.F.2.i. Beginning January 1, 2023, owners or operators of natural gas-driven pneumatic controllers located at natural gas-processing plants must inspect pneumatic controllers at least quarterly using an approved instrument monitoring method.

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

III.F.3. Enhanced response and remonitoring

III.F.3.a. Enhanced response must begin no later than five (5) working days and the pneumatic controller returned to proper operation no later than thirty (30) working days after determining the pneumatic controller is not operating properly, unless parts are unavailable, the equipment requires shutdown to complete enhanced response, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced response conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced response must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced response must be completed within fifteen (15) working days after the cause of delay ceases to exist.

III.F.3.b. Within fifteen (15) working days of completion of enhanced response, the owner or operator must verify the pneumatic controller is operating properly. In verifying proper operation, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.3.c. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Division unless the owner or operator fails to determine whether the pneumatic controller is operating properly in accordance with Section III.F.2., perform any necessary enhanced response in accordance with Section III.F.3., keep records in accordance with Section III.F.4., or submit reports in accordance with Section III.F.5.

III.F.4. Owners or operators must maintain the following records for a minimum of three (3) years and make records available to the Division upon request.

III.F.4.a. The date, facility name, facility AIRS ID or facility location if the facility does not have an AIRS ID, and approved instrument monitoring method used for each inspection;

III.F.4.b. A list of pneumatic controllers, including type, determined to be not operating properly;

III.F.4.c. For intermittent pneumatic controllers observed to have detectable emissions but determined to be operating properly, a brief explanation of the basis for concluding that the intermittent pneumatic controller was operating properly. The explanation can include, but is not limited to, an owner or operator’s standard operating procedure detailing how to determine whether an intermittent pneumatic controller is operating properly, or an individual explanation;

III.F.4.d. The date(s) of enhanced response and a description of the actions taken to return the pneumatic controller to proper operation;

III.F.4.e. The date the owner or operator verified the pneumatic controller was returned to proper operation; and

III.F.4.f. The delayed repair list, including the date and duration of any period where the enhanced response was delayed beyond thirty (30) days after determining the pneumatic controller is not operating properly due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for returning the pneumatic controller to proper operation. Delay of enhanced response due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for pneumatic controller inspection and enhanced response compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

III.F.5. Owners or operators of pneumatic controllers at well production facilities or natural gas compressor stations must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019 for facilities in the 8-Hour Ozone Control Area and May 31st, 2021, for facilities outside the 8-Hour Ozone Control Area) that includes, at a minimum, the following information regarding pneumatic controller inspection and enhanced response activities at their subject facilities conducted the previous calendar year. 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 31 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.

IV. (State Only) Control of Emissions from Natural Gas Transmission and Storage Segment

IV.A. Definitions

IV.A.1. “Best management practice” (BMP) means a demonstrated and commercially available or innovative emission-reducing technology or work practice.

IV.A.2. “Best management practices plan” (BMP plan) means a written plan that includes, but is not limited to, each natural gas transmission and storage segment owner or operator’s planned and implemented BMPs to reduce methane emissions from its facilities within the natural gas transmission and storage segment.

IV.A.3. “Natural gas transmission and storage segment” (segment) includes onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015), that are physically located in Colorado.

IV.A.4. “Natural gas transmission and storage segment Colorado throughput” (segment throughput) means the total volume of natural gas, as adjusted for methane, transported through transmission pipelines in Colorado as reported to the Department of Energy’s

(DOE) Energy Information Administration (EIA) for Form 176, excluding net volumes stored as liquefied natural gas or in underground storage facilities.

IV.A.5. "Natural gas transmission and storage segment emissions inventory protocol" (inventory protocol) means the requirements by which natural gas transmission and storage segment owners or operators will quantify and report methane, ethane, carbon monoxide (CO), carbon dioxide (CO2), nitrous oxide (N2O), nitrogen oxides (NOx), and volatile organic compound (VOC) emissions. The protocol will specify the segment facilities and types of activity data collected, emissions quantification methodologies, throughput calculation methodologies, criteria for determining whether events are beyond the control of the owner or operator, and the process for designating and protecting confidential business information (CBI), consistent with Colorado law.

IV.A.6. "Performance-based program" means a program of BMPs implemented and documented by each natural gas transmission and storage segment owner or operator to reduce methane emissions in order to achieve the system-wide emissions intensity target.

IV.A.7. "Steering committee" means five members approved by the Division to serve as a technical working group for developing program guidance documents and evaluating progress against the system-wide emissions intensity target. The committee members will include two representatives from natural gas transmission and storage segment owners or operators (or industry trade organizations representing owners or operators), two members representing the general public (including but not limited to environmental organizations, local government groups, or citizens), and one Division member.

IV.A.8. "Segment-wide emissions intensity" means the natural gas transmission and storage segment methane emissions divided by the natural gas transmission and storage segment throughput.

IV.A.9. "Segment-wide emissions intensity target" (segment-wide target) means the target established by the steering committee reflected as annual segment-wide methane emissions from Colorado's natural gas transmission and storage segment divided by the annual natural gas transmission and storage segment Colorado throughput.

IV.B. Beginning January 1, 2020, each segment owner or operator must participate in this performance based program to reduce segment-wide methane emissions.

IV.B.1. By April 1, 2020, a steering committee charter and the steering committee members will be approved by the Division.

IV.B.2. By September 30, 2020, the Division will publish the inventory protocol and any associated program guidance documents developed by the steering committee.

IV.B.3. By December 31, 2020, each segment owner or operator must develop a company-specific BMP plan. The BMP plan must contain each element from the BMP plan template chapter of the program guidance document, which will include, but is not limited to, a list of information the owner or operator must collect to demonstrate the BMPs performed. By December 31st of each year (beginning December 31st, 2021), each owner or operator must review and update, as appropriate, its company-specific BMP plan and document in the BMP plan any changes.

IV.B.4. Beginning January 1, 2021, each segment owner or operator will

IV.B.4.a. Implement company specific BMP plans.

IV.B.4.b. Collect emissions inventory data in accordance with the inventory protocol and its company-specific BMP plan.

IV.B.5. By May 1, 2022, the segment owners or operators will select a third-party contractor from a pool of qualified applicants to receive, safeguard, and aggregate company-specific reports as described in Sections IV.D.3. and IV.D.4. The steering committee will establish criteria for the selection of the third-party contractor. The segment owners and operators will use a competitive bidding process to solicit applications from contractors who meet the criteria and will provide an opportunity for the steering committee to reject unqualified applicants.

IV.B.6. By October 1, 2023, the steering committee will determine the segment-wide emissions intensity target using the 2021 and 2022 emissions inventory data. In developing the initial or updated segment-wide emissions intensity target and evaluating the program, the steering committee may request non-company specific information from the Division (in accordance with the Colorado Opens Record Act) or the third-party contractor to assist in setting such target or such evaluation. The steering committee may ask companies to explain emission factors and methodologies used to calculate or measure emissions.

IV.C. The segment-wide emissions intensity target must first be achieved by January 1, 2025, based on the 2024 reporting year.

IV.C.1. By October 1 of each year (beginning October 1, 2025), the steering committee will submit a compliance certification to the Division that the segment achieved the segment-wide emissions intensity target for the prior calendar year.

IV.C.2. If the steering committee cannot certify compliance with the segment-wide emissions intensity target, the steering committee will develop a plan (which may include amendments to program guidance documents) and timeline for the segment to achieve compliance with the segment-wide emissions intensity target.

IV.C.3. Beginning January 1, 2026, and every three (3) years thereafter if appropriate, the steering committee will assess the segment-wide emissions intensity target for continual improvement.

IV.D. Recordkeeping and reporting

IV.D.1. The Division will provide an update on the development of this program and initial implementation efforts to the Air Quality Control Commission during a scheduled Commission meeting on or after January 2021.

IV.D.2. Segment owners or operators must maintain BMP plans and emissions inventory reports for a period of five (5) years and make records available to the Division upon request.

IV.D.3. By June 30 of each year (beginning June 30, 2022), owners or operators of the natural gas transmission and storage segment will submit company-wide reports to the third-party contractor.

IV.D.3.a. Emissions claimed to be beyond the control of the owner or operator, using the criteria and methods established by the steering committee, must be included in the company-wide report but will not be used to set or determine compliance with the segment-wide emissions intensity target.

IV.D.3.b. Emissions and emission reductions associated with any requirements of the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Colorado Public Utilities Commission (CPUC), and/or the Federal Energy Regulatory Commission (FERC) must be included in the report and used for purposes of calculating compliance with the system-wide emissions intensity target, unless they qualify under Section IV.D.3.a., but this Section IV. does not supersede or alter these agencies applicable regulations or requirements.

IV.D.4. The third-party contractor must aggregate the company-wide reports into a segment-wide report and provide it to the steering committee by August 15 of each year (beginning August 15, 2022) on a form developed by the steering committee and approved by the Division. The segment-wide report must include, at a minimum

IV.D.4.a. The segment-wide emissions, apportioned by county,

IV.D.4.b. A report of the numbers and types of events subject to Section IV.D.3.a. and the segment-wide emissions resulting from each type of event.

IV.D.4.c. The BMPs implemented to mitigate or avoid emissions and a description of how the BMPs mitigate, reduce, and/or avoid emissions.

IV.D.4.d. The segment-wide segment throughput.

IV.D.4.e. The segment-wide emissions intensity. If the steering committee determines that one or more types of events reported under Section IV.D.4.b. were not beyond the control of the owner or operator, the steering committee will revise the segment-wide emissions intensity calculation to include the methane emissions from those events.

IV.D.5. Segment owners or operators must submit an annual certification to the Division by June 30 of each year (beginning June 30, 2021) that includes

IV.D.5.a. A certification that the company-specific BMP plan was developed or reviewed in accordance with Section IV.B.3.

IV.D.5.b. A certification that the company-wide report was submitted to the third-party contractor in accordance with Section IV.D.3.

IV.D.5.c. Beginning in 2022, a certification of company BMP plan compliance in accordance with Section IV.B.4., including

IV.D.5.c.(i) The company's implementation of the BMPs in the company-specific BMP plan.

IV.D.5.c.(ii) Instances of non-conformance with the company-specific BMP plan, reason(s) for non-conformance, and any modifications of the applicable element(s) of the BMP plan.

IV.D.5.c.(iii) Any use of alternative emission reduction approaches not specified in the company-specific BMP plan.

IV.D.5.d. With each submission under Sections IV.D.5.a. through IV.D.5.c., a certification by a responsible official that, based on information and belief after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IV.D.6. The Division may provide an update briefing to the Air Quality Control Commission during a scheduled Commission meeting on or after October 1 of each year (beginning October 1, 2022). The update briefing will include any assessment of the segment-wide target, as specified in Section IV.C.3.

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

V.A. Applicability

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

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

V.B. General reporting requirements

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

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

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

V.B.1.c. A list of the activities or equipment, as specified in Section V.C., for which emissions are reported. Beginning with the June 2022 report for the calendar year 2021, owners or operators must include whether the activities or equipment are located in a disproportionately impacted community.

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 assigned by the Colorado Oil and Gas Conservation Commission, and the total calendar year throughput of hydrocarbon liquids, produced water, and natural gas.

V.B.1.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- accepted calculation methods.

V.B.1.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-accepted calculation methods.

V.B.1.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- accepted calculation methods.

V.B.1.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.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 was 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 submit supporting documentation with the annual report that includes 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 or other Division-approved method.

V.B.1.i. Emission factors, beginning with the June 2022 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) Where the Division has published a default emission factor, owners or operators submitting reports under this section must use the state default factor or other Division- accepted 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 with the first annual emission report in which that site-specific emission factor is used (the calendar year 2021 report will be considered the first report for purposes of this section). If subsequent annual emission reports use the same emission factor, operators do not need to resubmit the supporting documentation.

V.B.1.i.(iii) Owners or operators using a site-specific emission factor must conduct a gas speciation analysis every five (5) years to verify the ongoing accuracy of the site-specific emission factor pursuant to a Division-accepted sampling method or protocol.

V.B.1.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, 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 or 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, where the physical volume between isolation valves is greater than or equal to 1 cubic foot.

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) Through the June 2023 report (for calendar year 2022), 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), where the physical volume between isolation valves is greater than or equal to 1 cubic foot.

V.C.2.d.(viii) Beginning with the June 2024 report for calendar year 2023, best practices employed pursuant to Section II.H.4.

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 or be reported pursuant to a different Division-approved format.

V.C.2.q. Natural gas pneumatic pumps, aggregated per facility. Pneumatic pumps at the wellhead must be aggregated with the associated facility or be reported pursuant to a different Division-approved format.

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, and aggregated by pigging unit.

V.C.2.s.(i) Beginning with the June 2024 report for calendar year 2023, capture or control methods or best practices employed pursuant to Sections II.H.1., II.H.2., or II.H.4. per pigging unit.

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

V.C.2.u. Process heaters.

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

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

V.C.2.x. Reciprocating compressor leaks or vents, aggregated per facility. Beginning with the June 2023 report for calendar year 2022, reciprocating compressor leaks or vents must be aggregated per compressor.

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

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

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

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

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

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

V.C.2.ff. Well workovers.

V.C.2.gg. Wellhead bradenhead.

V.D. Annual information reporting

V.D.1. Beginning in 2022, and each calendar year thereafter, the Division must prepare and send an annual information report to the Commission and the Colorado Oil and Gas Conservation Commission. The report must include

V.D.1.a. Summary and analysis of oil and gas emissions data received or produced by the Division, including but not limited to

V.D.1.a.(i) Oil and gas annual emissions reporting under Section V.;

V.D.1.a.(ii) An update on the Division's leak detection and repair program, including a summary of information reported under Section II.E., as well as the results of any aerial and ground-based surveys performed by or at the direction of the Division;

V.D.1.a.(iii) Data collected from early production operations monitoring data reported to the Division under Section VI.; and

V.D.1.a.(iv) Greenhouse gas intensity plans and annual verifications submitted pursuant to Section VII.E., specifically regarding the technologies and measures employed to reduce emissions from oil and gas production.

V.D.1.b. An evaluation of the progress toward the goals set forth in the Greenhouse Gas Pollution Reduction Roadmap; and any initiatives developed by the Division to achieve Colorado's statewide greenhouse gas emission reductions, and the role of oil and the role of oil and gas operations in achieving the reduction targets for the oil and gas sector;

V.D.1.c. Information regarding ambient air quality standard attainment, trends, and contributions from oil and gas operations, including ground-level ozone ambient air quality standards as presented to the Commission during the annual ozone presentation;

V.D.1.d. A summary of information collected pursuant to the community-based air toxics monitoring program performed by the Division under § 25-7-141(6), CRS;

V.D.1.e. Opportunities for inter-agency coordination, including workgroups, or basin-wide, statewide, or other regional studies to evaluate and address air quality issues related to oil and gas production; and

V.D.1.f. Additional information requested by the Commission or that the Division determines is relevant to achieving the state's greenhouse gas emission reduction targets or ozone attainment.

V.D.2. When transmitting information to the Colorado Oil and Gas Conservation Commission pursuant to Section V.D.1., the Division must make the report available to the public on the Division's website.

V.D.3. The Division must include the relevant annual information provided to the Colorado Oil and Gas Conservation Commission as part of the Division's report submitted every odd-numbered year to the General Assembly pursuant to § 25-7-105(1)(e)(V)), CRS. The Division must also submit the Division's General Assembly report to the Colorado Oil and Gas Conservation Commission.

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

VI.A. Definitions

VI.A.1. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

VI.A.2. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.

VI.A.3. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

VI.A.4. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

VI.A.5. “Flowback vessel” means a vessel that contains flowback.

VI.A.6. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

VI.A.7. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

VI.A.8. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

VI.A.9. “Tank measurement system” means equipment and methods used to determine the quantity of the liquids inside a flowback vessel without requiring direct access through the flowback vessel thief hatch or other opening.

VI.A.10. “Well” means a hole drilled for the purpose of producing oil and/or natural gas.

VI.A.11. “Well completion” means the process that allows for the flow of petroleum and/or natural gas from newly drilled wells, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic fracturing, drill-out, flowback).

VI.A.12. “Well re-completion” means the process that allows for the flow of petroleum and/or natural gas from an existing well from any geological interval not currently producing in the existing well, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic re-fracturing, drill-out, flowback).

VI.B. General provisions

VI.B.1. At all times the facility and equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions.

VI.B.2. Air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable and consistent with technological limitations and good engineering and maintenance practices.

VI.C. Air quality monitoring

VI.C.1. Owners or operators of drilling operations that begin on or after May 1, 2021, must monitor air quality at and/or around the pre-production and early production operations.

VI.C.1.a. Owners or operators must monitor air quality for at least ten (10) days prior to beginning pre-production operations, during all pre-production operations, and for at least six months after the well is capable of consistently producing either separable gas or salable liquid hydrocarbons (i.e., early production).

VI.C.1.b. Owners or operators must submit an air quality monitoring plan to the Division and the local government with jurisdiction over the location of the operations and any other local government unit, where applicable, within 2,000 feet of the proposed operations at least sixty (60) days prior to beginning air quality monitoring. Upon the request of any of these local government units within 14 days of receiving the plan, the Division will consult with them as part of its review process. Owners or operators must receive approval from the Division of the air quality monitoring plan prior to beginning air quality monitoring. Owners or operators must comply with the plan once approved. The air quality monitoring plan must include, at a minimum:

VI.C.1.b.(i) The owner or operator name and the contact information of the owner or operator representative for monitoring purposes.

VI.C.1.b.(ii) The planned schedule for drilling and pre-production operations.

VI.C.1.b.(iii) The operations to be monitored including the API number of the well(s), location of the operations including latitude and longitude coordinates, and any associated facility or equipment AIRS number(s).

VI.C.1.b.(iv) Whether the local government with jurisdiction over the location of the operations has air quality monitoring requirements applicable to pre-production and/or early production operations, a description of those requirements, and a local government contact for air quality monitoring purposes.

VI.C.1.b.(v) The monitoring objective(s), which must include one or more of the following (and may include additional objectives such as field-testing new air quality monitoring technologies or improving emissions inventories):

VI.C.1.b.(v)(A) Detect, evaluate, and reduce as necessary hazardous air pollutant emissions;

VI.C.1.b.(v)(B) Detect, evaluate, and reduce as necessary ozone precursor emissions;

VI.C.1.b.(v)(C) Detect, evaluate, and reduce as necessary methane emissions.

VI.C.1.b.(vi) The air pollutant(s) and other parameters to be monitored. Pollutants must include at least one of the following: total VOCs, methane, benzene or BTEX (benzene, toluene, ethyl benzene and xylenes) or other indicator of hydrocarbon emissions from pre-production and early production operations, as appropriate to meeting the specified monitoring objectives.

VI.C.1.b.(vii) A description of the monitoring equipment to be deployed, including the manufacturer and model information and any manufacturer specifications for the monitoring equipment and data systems. The description of pollutant monitoring equipment should explain why it was chosen and document or provide references describing relevant prior use and evaluations that are known to the owner or operator.

VI.C.1.b.(viii) A description of the meteorological monitoring equipment to be deployed. If meteorological data will not be collected on-site, the plan must provide reasoning and justification, and identify the meteorological station from which data will be obtained and demonstrate that the station represents conditions at the oil and gas development site.

VI.C.1.b.(ix) A monitor siting plan, which must include but is not limited to:

VI.C.1.b.(ix)(A) The number of monitors and/or sensors to be deployed.

VI.C.1.b.(ix)(B) The location and height of the monitoring equipment, including for each phase of operations if location and height of the equipment will change (e.g., monitoring placement impacted by sound walls).

VI.C.1.b.(ix)(C) A topographic map and plan of the site, showing the expected equipment layout, including air quality and meteorological monitor locations and their distance from pre-production and production operations. The map must indicate any obstructions to air flow to the monitor(s) and also show all roads and access ways within a half-mile of the facility and any contiguous structures, whether or not they are part of the production operations.

VI.C.1.b.(ix)(D) A description of how the placement of monitoring equipment minimizes surface disturbances, in alignment with the Colorado Oil and Gas Conservation Commission’s site preparation requirements.

VI.C.1.b.(ix)(E) An explanation of how the number and placement of monitoring equipment will be adequate to achieve the desired air quality monitoring objectives, considering the monitoring equipment’s detection limit and other limitations.

VI.C.1.b.(x) The standard operating procedures that will be employed, to include at minimum:

VI.C.1.b.(x)(A) The sampling and/or measurement interval, averaging times, minimum detection concentration or level, expected precision, and confidence level at which pollutant data will be reported.

VI.C.1.b.(x)(B) The response level for each pollutant or indicator monitored and/or sampled and the response procedures or actions that will be taken if elevated levels are observed.

VI.C.1.b.(x)(C) The data quality indicators for precision and bias of the monitoring equipment.

VI.C.1.b.(x)(D) The quality control and quality assurance procedures, including calibration intervals and frequency, which will be used to ensure proper operation of the monitoring equipment. Owners or operators may reference and attach an existing methodology.

VI.C.1.b.(x)(E) A discussion of known limitations of the pollutant monitoring equipment and, if applicable, how they will be addressed.

VI.C.1.b.(x)(F) The protocol that will be used for acquiring, processing, and recording relevant meteorological data.

VI.C.1.b.(x)(G) The data system and operating protocol to be used for data collection, including, but not limited to, data logging, data processing, recording, downloading, backup and storage, and reporting.

VI.C.1.b.(x)(H) The methods for collecting and analyzing speciated or other samples of chemical constituents identified by the Division when indicated necessary based on site-specific concentration thresholds, if applicable.

VI.C.1.b.(xi) A description of how the monitoring equipment, pollutant(s) monitored, and siting plan are expected to detect elevated emissions and achieve at least one of the monitoring objectives listed in Section VI.C.1.b.(v).

VI.C.1.c. Within ten (10) days of approving a monitoring plan, the Division will notify all local government units identified in Section VI.C.1.b. of the plan approval.

VI.C.2. Recordkeeping and reporting

VI.C.2.a. Owners or operators must keep the following records for a minimum of three (3) years, unless otherwise specified, and upon request make records available to the Division. Local governments identified in Section VI.C.1.b may request those records from the Division. If the Division has not requested the records and a local government(s) identified in Section VI.C.1.b requests the records from the Division, the Division shall request the records from the owner or operator.

VI.C.2.a.(i) The air quality monitoring plan.

VI.C.2.a.(ii) Monthly reports and the data necessary to inform the monthly reports, as provided in Section VI.C.2.b.

VI.C.2.a.(iii) Activity logs to inform Section VI.C.2.b.(iii)(A) of the monthly report.

VI.C.2.a.(iv) For a period of one year after the monthly report, the underlying raw data associated with each monitor.

VI.C.2.a.(v) For a period of one year after the monthly report, the meteorological data in the time intervals as close to the sampling and/or measurement intervals as possible.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VI.C.2.b.(x) 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.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.

VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).

VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.

VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.

VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.

VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

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

VI.D.3. Recordkeeping

VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including

VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.

VI.D.3.a.(ii) The date and time of the onset of flowback.

VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.

VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.

VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

VII. (State Only) Reduction of Emissions from Oil and Natural Gas Midstream Segment Fuel Combustion Equipment

VII.A. Definitions

VII.A.1. "8-hour ozone control area" means the Counties of Adams, Arapahoe, Boulder (includes part of Rocky Mountain National Park), Douglas, and Jefferson; the Cities and Counties of Denver and Broomfield; and the following portions of the Counties of Larimer and Weld

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

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

VII.A.2. "Co-benefits" for purposes of Section VII. means the reduction of harmful air pollutants in disproportionately impacted communities.

VII.A.3. "Company emission reduction plan" or "company ERP" means a plan prepared by a midstream segment owner or operator, consistent with the guidance issued by the midstream steering committee, to achieve that owner or operator's proportionate reductions of greenhouse gas emissions to meet the requirements of Section VII.

VII.A.4. “Disproportionately impacted community” (DI community) means census block groups designated as DI communities in CDPHE’s draft Data Viewer for Disproportionately Impacted Communities in Colorado (as of December 17, 2021, at: https://cohealthviz.dphe.state.co.us/t/EnvironmentalEpidemiologyPublic/views/EJActDICommunities-Public/HB21-1266DICommunities?%3AshowAppBanner=false&%3Adisplay_count=n&%3AshowVizHome=n&%3Aorigin=viz_share_link&%3AisGuestRedirectFromVizportal=y&%3Aembed=y) consistent with 24-4-109(2)(b)(II), C.R.S. (2021). A complete list of these census block groups by 12-digit FIPS code will be maintained by the Division and made publicly available.

VII.A.5. “Harmful air pollutants” for purposes of Section VII. means pollutants designated by EPA as criteria pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate pollution (PM) (PM2.5 and PM10) and sulfur dioxide) or hazardous air pollutants.

VII.A.6. “Midstream fuel combustion equipment” means engines, turbines, process and other heaters, boilers, and reboilers in the midstream segment.

VII.A.7. “Midstream segment” means the oil and natural gas compression segment and the natural gas processing segment that are physically located in Colorado and that are upstream of the natural gas transmission and storage segment.

VII.A.8. “Midstream segment emission reduction plan” or “segment ERP” means a plan establishing the process and timelines for the midstream segment to achieve twenty percent (20%) reduction in greenhouse gas emissions (in CO2e) from midstream segment fuel combustion equipment by no later than December 31, 2030.

VII.A.9. “Midstream steering committee” means a committee comprised of members approved by the Division to serve as a technical working group tasked with developing program guidance documents and developing a midstream segment emission reduction plan. To the extent practicable, the committee members will include two members representing the electric utility sector; three members representing the midstream segment (at least one representing the oil and natural gas compression segment and one representing the natural gas processing segment), or industry trade organizations representing owners or operators; at least three local government representatives (one from inside the 8-hour ozone control area and northern Weld County and one from outside the 8-hour ozone control area and northern Weld County); at least three members representing the general public (including a representative of an environmental organization and a representative of a disproportionately impacted community); and at least one Division staff person. The steering committee may also include two additional members: a representative from the Colorado Energy Office and a representative from the Public Utilities Commission.

VII.A.10. “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.

VII.A.11. “Natural gas transmission and storage segment” includes onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015) that are physically located in Colorado.

VII.A.12. "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.

VII.A.13. "Oil and natural gas compression segment" means the oil and natural gas compression, midstream 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 VII., equipment located at a well production facility, including but not limited to compressors, is excluded from the oil and natural gas compression segment.

VII.A.14. "Residue gas" and "residue gas compression" mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

VII.B. Beginning January 1, 2022, each midstream segment owner or operator must participate in this Section VII. program to reduce greenhouse gas emissions from midstream fuel combustion equipment by twenty percent (20%) over the 2015 baseline as determined by § 25-7-140(2)(a)(II), C.R.S.

VII.C. Creation of the Midstream Steering Committee and Initial Information Collection

VII.C.1. By February 28, 2022, the midstream steering committee members will be approved by the Division. The first midstream steering committee meeting will be held no later than March 31, 2022, and thereafter at least monthly at a time and place determined by the midstream steering committee.

VII.C.2. By no later than April 30, 2022, the midstream steering committee will initiate an information and data collection process through which it will seek and obtain information in addition to the reports provided pursuant to Section VII.C.3. necessary to inform its technical analyses and policy considerations and comply with its duties under Section VII.

VII.C.2.a. The midstream steering committee will seek publicly available information concerning most recently filed electric utility Electric Resource Plans and Clean Energy Plans; regarding the forecast timing of upcoming Electric Resource Plan filings, electric utility energy sales and demand forecasts for 2023 through 2030; and regarding existing and contracted electric generation units, and approved future transmission lines in Colorado.

VII.C.2.b. The Division will provide the midstream steering committee with the 2015 baseline CO2e emissions from the industrial sector identified in § 25-7-105(1)(e)(XIII), C.R.S. (2021).

VII.C.3. By no later than July 31, 2022, each midstream segment owner or operator must provide the following information to the midstream steering committee on a Division-approved form to inform the guidance document that will be developed pursuant to Section VII.D.1.

VII.C.3.a. The facility name, AIRS ID (if applicable), and location (with coordinates) of each of the owner or operator's natural gas processing plants and natural gas compressor stations.

VII.C.3.b. An inventory of all midstream fuel combustion equipment owned or operated by the midstream segment owner or operator including midstream fuel combustion equipment not located at a natural gas processing plant or natural gas compressor station. The inventory must identify which equipment is located within a disproportionately impacted community. The inventory must include the type of equipment (e.g., engine, boiler) and the total CO2, methane, and CO2e emissions from each piece of equipment in calendar years 2020 and 2021 as reported to the Division in accordance with Regulation Number 7, Part B, Section V. If different calculation methods were used to report emissions from midstream fuel combustion equipment to the U.S. EPA under the federal Greenhouse Gas Reporting Program, 40 C.F.R. Part 98, the inventory must include the emissions reported to the U.S. EPA for the equipment included in this inventory and an explanation of the changed method of calculation.

VII.C.3.c. An estimate of the total annual power demand, along with total instantaneous power demand in kilowatt hours, or horsepower demand required for use of the midstream fuel combustion equipment identified in Section VII.C.3.b.

VII.C.3.d. An inventory of all electric motors driving gas compressors or electric heaters owned or operated by the midstream segment owner or operator including the facility where located (as applicable) and the date the electric equipment commenced operation.

VII.C.3.e. An estimate of the total annual kilowatt hours and heat rate demand, along with total instantaneous power demand, being supplied by electric motors and electric heaters identified in Section VII.C.3.d.

VII.C.3.f. An estimate of existing transmission and distribution capacity to serve estimated load in a specific location as supplied by the applicable electric, transmission, or distribution service provider.

VII.D. Midstream Steering Committee Duties, Guidance, Company ERPs, and Segment ERPs

VII.D.1. The midstream steering committee will develop and issue one or more guidance documents for midstream segment owners and operators to submit company ERPs to the steering committee. The guidance will

VII.D.1.a. Identify the sources that a midstream segment owner or operator must include in its company ERP, including the facilities, activities, and midstream fuel combustion equipment.

VII.D.1.b. Identify the total tons of CO2e reduction to be achieved by the segment ERP, consistent with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

VII.D.1.c. Provide a methodology by which each midstream segment owner or operator will determine the total tons of CO2e reduction from midstream fuel combustion equipment to be achieved by that owner or operator. The methodology should take into account, without limitation, the emission reductions from midstream fuel combustion equipment achieved by the owner or operator from 2015 midstream fuel combustion equipment emission levels and the amount of emissions reduced by electrification of midstream fuel combustion equipment achieved by the midstream segment owner or operator.

VII.D.1.d. Prescribe how CO2e emissions and emission reductions will be calculated in the company ERP, consistent with, to the extent feasible, the requirements of §§ 25-7-105(1)(e) and -140, C.R.S. (2021) and Regulation Number 7, Part B, Section V. The Division must approve of emission calculation methodologies before they can be included in the midstream steering committee guidance document(s).

VII.D.1.e. To aid midstream owners and operators in ensuring CO2e emission reductions and co-benefits, identify and describe environmental justice considerations for midstream segment fuel combustion equipment affecting disproportionately impacted communities, including potential air quality impacts or improvements, other non-air environmental benefits or detriments, employment opportunities, and regional economic impacts that must be considered by midstream segment owners or operators in their company ERPs.

VII.D.1.f. Identify and describe methods by which midstream segment owners or operators can achieve the emission reductions necessary to comply with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021), including, but not limited to, equipment replacement, equipment retrofit, equipment shutdown, or electrification. The guidance should also seek to identify and describe issues that must be addressed by operators considering electrification as an emission reduction strategy

VII.D.1.g. Describe how midstream segment owners or operators can account for changes in and avoid increases to NOx or VOC emissions in securing the CO2e emission reductions necessary to meet the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

VII.D.1.h. Describe how midstream segment owners or operators should account for costs associated with achieving required emission reductions from midstream segment fuel combustion equipment in their company ERPs, including capital costs, annualized equipment costs, annual operating costs, and costs in dollars per ton of CO2e reduced.

VII.D.1.i. Describe how midstream segment owners or operators should incorporate midstream segment fuel combustion equipment that commences operation after September 30, 2023, into their company ERPs.

VII.D.2. No later than December 31, 2022, the Division will make the draft midstream steering committee guidance document(s) available for at least 30 days of public comment.

VII.D.3. By March 31, 2023, the midstream steering committee will publish its final guidance document(s) for the development of company ERPs.

VII.D.4. By September 30, 2023, each midstream segment owner or operator must submit to the midstream steering committee its company ERP, consistent with and containing all the information identified in the guidance issued by the midstream steering committee, to achieve CO_2e reductions from the owner or operator's midstream segment fuel combustion equipment, prioritizing greenhouse gas emission reductions that have co-benefits. The Division will develop emission reduction requirements for an owner or operator that fails to submit a company ERP.

VII.D.5. By March 31, 2024, the midstream steering committee will develop a midstream segment ERP, and provide the proposed midstream segment ERP to the Division for review. The proposed midstream segment ERP will

VII.D.5.a. Identify the total tons of CO_2e reduction from midstream segment fuel combustion equipment to be achieved by the midstream segment ERP, consistent with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

VII.D.5.b. Identify the total tons of CO_2e reduction from midstream segment fuel combustion equipment to be achieved by each midstream segment owner or operator, consistent with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

VII.D.5.c. Identify the midstream segment facilities and fuel combustion equipment addressed by the midstream segment ERP.

VII.D.5.d. Prescribe the process and timing for midstream segment owners or operators to implement CO_2e emission reduction strategies for midstream fuel combustion equipment, including, but not limited to, electrification, retrofit, shut-down, or replacement.

VII.D.5.e. Describe how the implementation of the midstream segment ERP will affect disproportionately impacted communities within which midstream fuel combustion equipment is located, including a description of the percentage of CO_2e emission reductions in disproportionately impacted communities that will be achieved by the midstream segment ERP as a percentage of total emission reductions to be achieved by the midstream segment ERP. The midstream segment ERP must ensure and prioritize CO_2e reductions with co-benefits in disproportionately impacted communities, identify the disproportionately impacted communities in which the co-benefits will be achieved, and must attempt to quantify the co-benefits associated with the midstream segment ERP.

VII.D.5.f. Prescribe how emission reductions will be achieved for midstream segment fuel combustion equipment that is modified, constructed, or relocated to Colorado on or after September 30, 2023.

VII.D.5.g. Prescribe any additional recordkeeping and reporting requirements over and above existing provisions of Regulation Number 7, sufficient to ensure enforceability and verification of the midstream segment ERP.

VII.D.5.h. To the extent feasible, the midstream segment ERP will report the total estimated cost to midstream segment owners and operators to achieve the CO_2e reductions in the midstream segment ERP and the impact on CO_2e emissions from electrical generating units in Colorado resulting from electrification of midstream fuel combustion equipment as set forth in the midstream segment ERP.

VII.D.6. Following receipt of the midstream segment ERP from the midstream steering committee, the Division will make the draft midstream segment ERP available for at least 30 days of public comment.

VII.D.7. By no later than August 31, 2024, the Division will submit a regulatory proposal based upon the midstream segment ERP to the Air Quality Control Commission and request a rulemaking hearing for no later than December 31, 2024.

VII.E. Recordkeeping and Reporting. This Section VII.E will be repealed upon adoption by the Air Quality Control Commission of regulations addressing midstream fuel combustion equipment to meet the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

VII.E.1. Midstream segment owners or operators must retain records of information submitted to the Division or midstream steering committee, including information supporting the company ERP, for three (3) years and make them available for inspection by the Division upon request.

VII.E.2. Midstream segment owners or operators must retain records of actions taken after January 1, 2022, to reduce CO2e emissions from their midstream fuel combustion equipment.

VII.E.3. The Division will provide an update on the development of this program and initial implementation efforts to the Air Quality Control Commission during a scheduled Air Quality Control Commission meeting in or after July 2023.

VIII. (State Only) Greenhouse Gas Intensity Program for Oil and Natural Gas Upstream Segment

VIII.A. Definitions

VIII.A.1. “Calendar year” means January 1 up through and including December 31 of the year.

VIII.A.2. “Co-benefits” for this Section VIII. means the reduction of harmful air pollutants in disproportionately impacted communities.

VIII.A.3. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

VIII.A.4. “Controlling interest” for this Section VIII. means an interest that provides a person, either directly or indirectly, the power to direct or cause the direction of the management and policies of another person, whether through ownership or voting securities, by contract, or otherwise.

VIII.A.5. “Disproportionately impacted community” (DI community) means census block groups designated as DI communities in CDPHE’s draft Data Viewer for Disproportionately Impacted Communities in Colorado (as of December 17, 2021, at: https://cohealthviz.dphe.state.co.us/t/EnvironmentalEpidemiologyPublic/views/EJActDICommunities-Public/HB21-1266DICommunities?%3AshowAppBanner=false&%3Adisplay_count=n&%3AshowVizHome=n&%3Aorigin=viz_share_link&%3AisGuestRedirectFromVizportal=y&%3Aembed=y) consistent with 24-4-109(2)(b)(II), C.R.S. (2021). A complete list of these census block groups by 12-digit FIPS code will be maintained by the Division and made publicly available.

VIII.A.6. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.

VIII.A.7. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

VIII.A.8. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

VIII.A.9. “Greenhouse gas intensity” means the sum of preproduction emissions and production emissions in a calendar year in mtCO2e divided by the kBOE for that calendar year, calculated pursuant to Section VIII.D.

VIII.A.10. “Harmful air pollutants” for purposes of Section VIII. means pollutants designated by EPA as criteria pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate pollution (PM) (PM2.5 and PM10) and sulfur dioxide) or hazardous air pollutants.

VIII.A.11. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

VIII.A.12. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

VIII.A.13. “Intensity operator” means a person or entity that operates upstream segment activities or equipment. For purposes of Section VIII., where a person or entity holds a controlling interest in more than one intensity operator, that person or entity is the intensity operator of all upstream segment activities and equipment in which that person or entity has a controlling interest.

VIII.A.14. “kBOE” means production of hydrocarbon liquids and natural gas, measured in thousands of barrels of oil equivalent.

VIII.A.15. “mtCO2e” means metric tons (mt) of carbon dioxide equivalent, using global warming potential values from the IPCC Fifth Assessment Report, 2014 (AR5).

VIII.A.16. "Majority operator" means (1) an intensity operator with company-wide production in Colorado in calendar year 2022 of greater than or equal to 10,000 kBOE; (2) a new to market operator whose first transaction(s) in Colorado is to purchase the assets of a majority operator; (3) a new to market operator for which the total level of production from all assets acquired or developed in that calendar year exceeds 10,000 kBOE; (4) a new to market operator who has not purchased assets from a majority or minority operator and who commences operation of a well production facility after January 1, 2023; and (5) a minority operator that becomes a majority operator pursuant to Section VIII.B.6.

VIII.A.17. "Midstream segment" means the oil and natural gas compression segment and the natural gas processing segment that are physically located in Colorado and that are upstream of the natural gas transmission and storage segment.

VIII.A.18. "Minority operator" means an intensity operator with company-wide production of hydrocarbon liquids and natural gas in Colorado in calendar year 2022 of less than 10,000 kBOE. Minority operator also means a new to market operator whose first transaction(s) in Colorado is to purchase the assets of a minority operator, as long as the total level of production from all assets acquired or developed by (in the case of new well production facilities) of the new to market operator in that calendar year does not exceed 10,000 kBOE.

VIII.A.19. "New to market operator" means an owner or operator that did not produce any oil or natural gas in Colorado in calendar years 2021 or 2022 or own or operate any well production facility in Colorado as of December 31, 2022. A new to market operator that becomes a majority operator as defined in Section VIII.A.16. or a minority operator as defined in Section VIII.A.18. is no longer a new to market operator.

VIII.A.20. "Preproduction emissions" means the greenhouse gas emitted from an oil or natural gas well and associated equipment and activities during the construction and operation of the oil or natural gas well until the well commences operation, including from the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of the oil and/or natural gas well.

VIII.A.21. "Production emissions" means the greenhouse gas emitted from an oil or natural gas well and associated equipment and activities after the well commences operation.

VIII.A.22. "Upstream segment" means oil and natural gas exploration and production operations physically located in Colorado upstream of the midstream segment.

VIII.A.23. "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.

VIII.B. Greenhouse gas intensity targets for the upstream segment.

VIII.B.1. Beginning January 1, 2023, intensity operators must participate in this greenhouse gas intensity program to reduce preproduction and production emissions in Colorado. An intensity operator that fails to achieve any of the applicable targets in Section VIII.B. must achieve additional reductions in preproduction and/or production emissions in the subsequent calendar year to address the difference between the intensity operator's reported greenhouse gas intensity for that calendar year and the applicable target.

VIII.B.2. For calendar year 2025, intensity operators subject to Section VIII.B.1. must achieve the following greenhouse gas intensity targets for preproduction and production emissions.

VIII.B.2.a. Majority Operator: 10.94 mtCO2e/kBOE.

VIII.B.2.b. Minority Operator: 34.39 mtCO2e/kBOE.

VIII.B.3. For calendar year 2027, intensity operators subject to Section VIII.B.1. must achieve the following greenhouse gas intensity targets for preproduction and production emissions.

VIII.B.3.a. Majority Operator: 8.46 mtCO2e/kBOE.

VIII.B.3.b. Minority Operator: 26.60 mtCO2e/kBOE.

VIII.B.4. For calendar year 2030, intensity operators subject to Section VIII.B.1. must achieve the following greenhouse gas intensity targets for preproduction and production emissions.

VIII.B.4.a. Majority Operator: 6.80 mtCO2e/kBOE.

VIII.B.4.b. Minority Operator: 21.38 mtCO2e/kBOE.

VIII.B.5. In calendar years 2026, 2028, and 2029, intensity operators subject to Section VIII.B.1. must achieve a greenhouse gas intensity less than or equal to the applicable preceding year target in Sections VIII.B.2. and VIII.B.3. (e.g., for calendar year 2026 achieve at least the target for calendar year 2025).

VIII.B.6. If, in any calendar year beginning 2023, a minority operator

VIII.B.6.a. Has production of greater than or equal to 10,000 kBOE or

VIII.B.6.b. Has production that represents an increase over production in the prior calendar year by greater than or equal to 2,500 kBOE (e.g., if production is 2,500 kBOE higher in 2023 than it was in 2022), then

VIII.B.6.c. Beginning the calendar year after the applicable circumstances under Sections VIII.B.6.a. or VIII.B.6.b., unless otherwise approved by the Division, the minority operator becomes a majority operator and must comply with the applicable majority operator greenhouse gas intensity targets for all its upstream segment operations for that year and all remaining years through 2030.

VIII.B.7. Acquisitions. Except as provided, if an owner or operator acquires or takes over operation of an oil or natural gas well in Colorado after January 1, 2025, that owner or operator must meet the greenhouse gas intensity targets in Sections VIII.B.2. through VIII.B.5. applicable to the intensity operator acquiring the assets.

VIII.B.7.a. If a majority operator merges with, acquires, or takes over operation of an oil or natural gas well in Colorado from a minority operator on or after January 1, 2025, the majority operator (or surviving entity) must at least comply with the applicable minority operator greenhouse gas intensity target for the preproduction and production emissions from the acquired well(s) for the calendar year of the acquisition. Beginning with the calendar year after the acquisition, the applicable majority owner or operator must comply with the applicable majority operator greenhouse gas intensity targets for the preproduction and production emissions from all its upstream segment operations, including the acquired well(s).

VIII.B.7.b. If a minority operator acquires or takes over operation of an oil or natural gas well in Colorado from a majority operator on or after January 1, 2025, the minority operator must at least comply with the applicable minority operator greenhouse gas intensity target for the preproduction and production emissions from the acquired well(s) for the calendar years of and after the acquisition, after which the minority operator greenhouse gas intensity targets apply to all assets of the minority operator, including the acquired assets (unless the minority operator has become a majority operator).

VIII.C. New facility intensity targets.

VIII.C.1. Beginning January 1, 2023, intensity operators of well production facilities that commence operation after December 31, 2022, must also meet the new facility intensity target(s) for those facilities as set forth in Sections VIII.C.2. through VIII.C.4. in the calendar year of and the calendar year after the well production facility commences operation. These targets are in addition to the targets applicable to all of the intensity operator's upstream segment operations as specified in Section VIII.B.

VIII.C.1.a. For purposes of Section VIII.C., "new facility intensity" means the production emissions in CO2e from all well production facilities commencing operation in a calendar year divided by the production of hydrocarbon liquid and natural gas from those facilities in kBOE for that calendar year.

VIII.C.2. For calendar years 2023 through 2025, the new facility intensity target is 8.59 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 7.7 mtCO2e/kBOE.

VIII.C.3. For calendar years 2026 through 2027, the new facility intensity target is 6.64 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 6.0 mtCO2e/kBOE.

VIII.C.4. For calendar years 2028 through 2030, the new facility intensity target is 5.34 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 4.8 mtCO2e/kBOE.

VIII.D. Accounting for production kBOE, preproduction emissions, and production emissions.

VIII.D.1. Production can only be allocated to one intensity operator for the same time period. Intensity operators must account for production from all oil or natural gas wells and well production facilities in which the intensity operator holds the controlling interest. Intensity operators must account for production during the time in which the intensity operator holds that controlling interest.

VIII.D.2. Intensity operators must calculate kBOE by adding the production of hydrocarbon liquids in thousand barrels to the proportion of natural gas (calculated by dividing the million standard cubic feet (MMscf) volume of natural gas produced by the conversion rate of 5.8 MMscf/kBOE).

VIII.D.3. The intensity operator that reports the preproduction emissions and production emissions for upstream segment activities and equipment must report the kBOE associated with those activities and equipment.

VIII.E. Intensity operator greenhouse gas intensity plans.

VIII.E.1. Greenhouse gas intensity plans must be submitted on a Division-approved format and must contain, at a minimum

VIII.E.1.a. An identification of all the intensity operator’s well production facilities, including facility name; facility AIRS ID, or facility location if the facility does not have an AIRS ID; entity listed as the operator for all well production facilities covered by the greenhouse gas intensity plan for which production is included as specified under Section VIII.D.1.; and an identification of which facilities are located within a disproportionately impacted community.

VIII.E.1.b. The intensity operator’s greenhouse gas intensity company-wide and per well production facility for the preceding calendar year, including intensity calculation methodology.

VIII.E.1.c. A list and description of the best management practices (BMPs), control methods, emission reduction strategies, and technologies the intensity operator intends to use to meet the applicable targets in Section IV.B.2. on a site-specific basis.

VIII.E.1.d. An estimate of the greenhouse gas emission reductions that each type of BMP, control method, emission reduction strategy, or technology is expected to achieve on a company-wide mass basis and on a company-wide greenhouse gas intensity basis, including calculation methods.

VIII.E.1.e. A description of which BMPs, control methods, emission reduction strategies, and technologies will be deployed in disproportionately impacted communities, and a demonstration that intensity operators will prioritize co-benefits.

VIII.E.2. Greenhouse gas intensity plan submittal deadlines.

VIII.E.2.a. By August 31, 2023, each intensity operator subject to Section VIII.B.1. must submit to the Division a proposed greenhouse gas intensity plan demonstrating how the intensity operator intends to meet the applicable greenhouse gas intensity targets in Section VIII.B.2.

VIII.E.2.b. By June 30, 2025, each intensity operator subject to Section VIII.B.1. must submit to the Division a greenhouse gas intensity plan demonstrating how the intensity operator will meet the applicable greenhouse gas intensity targets in Section VIII.B.3.

VIII.E.2.c. By June 30, 2027, each intensity operator subject to Section VIII.B.1. must submit to the Division a greenhouse gas intensity plan demonstrating how the intensity operator will meet the applicable greenhouse gas intensity targets in Section VIII.B.4.

VIII.E.3. Asset transfer updates.

VIII.E.3.a. Section VIII.E.3. applies whenever ownership or operation of an oil or natural gas well or well production facility is transferred after August 31, 2024. The operator taking over operation of the oil or natural gas well or well production facility is referred to herein as the "acquiring operator". The intensity operator from whom ownership or operation is transferred is referred to as the "selling operator."

VIII.E.3.b. If the transaction involves any well production facility for which the selling operator's greenhouse gas intensity plan submitted under Section VIII.E.2. provides for implementation of any BMP, control method, emission reduction strategy, or technology, then within thirty (30) days of closing of the transaction.

VIII.E.3.b.(i) The selling operator must submit an update to its greenhouse gas intensity plan that:

VIII.E.3.b.(i)(A) Identifies each well production facility transferred (name and AIRS ID, if applicable), the name of the acquiring operator, and the date of closing of the transaction.

VIII.E.3.b.(i)(B) Includes a quantification of the emission reductions that would have been achieved at each well production facility involved in the transaction under the greenhouse gas intensity plan consistent with the calculation methods used in Section VIII.E.1.d.

VIII.E.3.b.(i)(C) Includes a demonstration that the selling operator will still meet its greenhouse gas intensity targets and identifies any additional BMPs, control method, emission reduction strategy, and technologies consistent with Section VIII.E.1.

VIII.E.3.b.(ii) The acquiring operator must submit an update to its greenhouse gas intensity plan (or, in the event the acquiring operator is also a new to market operator, the acquiring operator must submit a new greenhouse gas intensity plan) that, for each well production facility involved in the transaction

VIII.E.3.b.(ii)(A) Identifies the well production facility transferred (name and AIRS ID, if applicable), the name of the selling operator, and the date of closing of the transaction.

VIII.E.3.b.(ii)(B) Commits to implementing the same BMP, control method, emission reduction strategy, and technology provided for in the selling operator's plan on the same schedule; or

VIII.E.3.b.(ii)(C) Quantifies the emission reductions that would have been achieved under the selling operator's greenhouse gas intensity plan consistent with the calculation methods used in Section VIII.E.1.d. and identifies how the acquiring operator will achieve equal or greater emission reductions at the same or other well production facilities involved in the transaction (or, if approved by the Division, at other of the acquiring operator's well production facilities) on the same schedule.

VIII.E.4. Annual verifications.

By June 30 of 2024 through 2031, intensity operators must submit annual verifications on a Division-approved form to the Division summarizing the intensity operator's greenhouse gas intensity plan implementation during the preceding calendar year. The annual verification must include, at a minimum:

VIII.E.4.a. The intensity operator's implementation of the types of BMPs, control measures, emission reduction strategies, and technologies in its greenhouse gas intensity plan, on a site-specific basis (by location name and AIRS ID, if applicable, and whether the site is located within a disproportionately impacted community) for each BMP, control method, emission reduction strategy, and technology implemented.

VIII.E.4.b. If applicable, an identification of new well production facilities subject to Section VIII.C. commencing operation in that calendar year.

VIII.E.4.c. If applicable, the intensity operator's implementation of BMPs, control measures, emission reduction strategies, and technologies to achieve the new facility intensity target at all sites subject to Section VIII.C. on a site-specific basis (by location name and AIRS ID, if applicable.

VIII.E.4.d. Instances of departure from the intensity operator's greenhouse gas intensity plan, reason(s) for departure, and any modifications of the applicable element(s) of the BMP plan.

VIII.E.4.e. Use of any alternative emission reduction approaches not specified in the intensity operator's greenhouse gas intensity plan.

VIII.E.4.f. A demonstration that emission reductions were prioritized in disproportionately impacted communities, including a quantification of co-benefits achieved.

VIII.E.4.g. Identification by location name, AIRS ID (if applicable), well API number, and COGCC location ID (if applicable) of any oil or natural gas wells acquired or divested during the previous calendar year; the date of acquisition or divestment; and the name of the operator from which the well(s) were acquired or to whom the well(s) were divested.

VIII.E.4.h. A certification by a company representative with oversight over the operator's greenhouse gas intensity program that the annual verification is accurate and complete, to the best of the representative's knowledge and, if applicable, that measures identified in an asset transfer update submitted under Section IV.E.3 have been implemented as described therein.

VIII.F. Verification.

VIII.F.1. By no later than March 2023, the Division will submit a petition for rulemaking with a proposed verification plan for how intensity operators will demonstrate compliance with applicable greenhouse gas intensity targets in Sections VIII.B. and VIII.C. to the Air Quality Control Commission. In preparing the proposal, the Division must:

VIII.F.1.a. Propose appropriate calculation and emission quantification methodologies for the emissions categories to be included in a demonstration of compliance with the greenhouse gas intensity targets in Section VIII., taking into account the relative accuracy, reliability, and feasibility of the methodologies.

VIII.F.1.b. Ensure the proposal addresses the relative completeness and reliability of the annual emission reports submitted pursuant to Regulation Numbers 7, Part B, Sections II.G. and V.

VIII.F.1.c. Ensure the proposal addresses the results of the aerial and ground-based method surveys, including those conducted by the Division in 2021, and how those surveys should be used to ensure abnormal operating conditions and other large hydrocarbon emission events are accounted for in the demonstration of compliance with the greenhouse gas intensity and new facility intensity targets.

VIII.F.1.d. Include recommendations for provisions the Division determines are necessary to ensure the enforceability of the greenhouse gas intensity and new facility targets, such as additional monitoring.

VIII.F.1.e. Include recommendations to evaluate total greenhouse gas emissions relative to the applicable baseline and progress towards statewide greenhouse gas emission reduction goals for oil and gas emissions in § 25-7-105(1)(e)(XII) and (XIII), CRS.

PART C Statements of Basis, Specific Statutory Authority and Purpose

A. December 21, 1995 (Section II.B.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Numbers 3, 7, and the Common Provision are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists of the EPA list of non-photochemically VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all Colorado Air Quality Control Commission regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly-reactive VOC, industry’s will be able to take advantage of and benefit from this possible shift in product contents.

B. March 21, 1996 (Sections I.A.1. through I.A.4.; II.D.; II.E.)

The changes to Regulation Number 7 were adopted as part of the Commission's decision to redesignate the Denver metro area as an attainment and maintenance area for ozone, together with the relevant amendments to the Ambient Air Quality Standards regulation and Regulation Number 3. The Ozone Maintenance Plan, also adopted by the Commission on March 21, 1996 as part of the redesignation, based part of its demonstration of maintenance on the continued existence of rules regulating VOC emissions. Such rules include the application of the permit requirements of Regulation Number 3 to gasoline stations, and the continued application of Regulation Number 7 for the control of VOC in nonattainment areas. The VOC controls in Regulation Number 7 were adopted into the SIP in May 1995, after Denver attained the ozone standard. The maintenance demonstration was based on future inventories that assumed the continuance of existing VOC controls in the Denver Metro area.

Pursuant to Section 25-7-107(2.5), C.R.S., the Commission is required to take expeditious action to redesignate the area as an attainment area for ozone. The CAA requires the submittal of a maintenance plan demonstrating maintenance of the ozone standard for any such redesignation request. The changes to Regulation Number 7 are consistent with continued maintenance of the ozone standard and are not otherwise more stringent than the relevant federal requirements.

The purpose of the revisions to Regulation Number 7, Section I.A is to provide a de minimis source with an opportunity to obtain an exemption from the requirements of Regulation Number 7 through rule-making. This revision will be submitted to the EPA for inclusion in the State Implementation Plan (SIP). Upon inclusion of this revision in the SIP, exemptions from Regulation Number 7 adopted by the Commission shall apply for purposes of both federal and state law, pending review by the state legislature pursuant to § 25-7-133(2), C.R.S. The rule revision includes several limitations on the scope of such exemptions:

1. The aggregate of all emissions from de minimis sources may not exceed five tons of emissions per day. The purpose of this limitation is to protect the projections contained in the emissions inventory, and to prevent growth in such emissions from exceeding the National Ambient Air Quality Standard (NAAQS) for ozone.

2. An exemption may not be granted if the Division demonstrates that such exemption will cause or contribute to air pollution levels that exceed the NAAQS, even if the total aggregate emissions from such sources is less than five tons per day.

3. The Commission rule prohibits more than one rulemaking hearing per year to consider potential de minimis exemptions in the aggregate. The purpose of this provision is to prevent the granting of case-by-case exemptions, and to conserve agency resources. The granting of exemptions on a case-by-case basis would grant an unfair advantage for those sources that are able to have their case heard by the Commission before other, similarly situated sources, submit a request for a de minimis exemption. However, upon a showing of an emergency, and at the discretion of the Commission, the Commission may always grant an exemption on a case-by-case basis.

4. The Commission rule provides that the growth in emissions due to such de minimis exemptions may not exceed the growth that was included in the emissions inventory in the SIP.

5. The Commission rule requires the de minimis exemptions to be included in a permit that is subject to review and comment by the public and by EPA.

The rule revision proposed by the Regional Air Quality Council (RAQC) did not include these limitations. However, the Commission may not have used the rule as proposed by RAQC to grant unlimited exemptions from the requirements of Regulation Number 7 because such an action would undermine the regulation and the maintenance demonstration contained in the SIP. The limitations adopted by the Commission were the subject of an alternative proposal submitted by the Division. The purpose of the limit is to ensure that the de minimis exemption provision cannot be used to jeopardize attainment of the NAAQs. Such a limit is necessary in order to obtain EPA approval of this SIP revision. The alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity. Even without an express provision limiting the de minimis exemptions to five tons per day, the Commission generally would not have granted de minimis exemptions in excess of that amount because such emissions are not accounted for in the emissions inventory and would undermine the maintenance demonstration. Furthermore, the alternative proposed by the Division does not, by itself, create an exemption from any regulatory requirement. The alternative simply limits the scope of the exemptions that may become fully effective without a SIP revision. However, the rule does not in any way limit the Commission's authority to amend the SIP.

The emissions inventory submitted to EPA anticipated growth in emissions in both the area source and minor source categories, as well as the major source category. In order to ensure that any growth in emissions due to the granting of de minimis exemptions will not cause total emissions to exceed the growth projections for these categories, the Division will keep track of the permitted allowable emissions that may result from sources and source categories entitled to such exemptions. In addition, the growth in emissions from area, major and minor source categories will be tracked when the Division performs the periodic inventories described in the SIP for the years 1999, 2002 and 2003. Any permitted growth in emissions due to de minimis exemptions will be added to the emissions for the source categories as reflected in the most recent periodic inventory. No further de minimis exemptions will be granted if the total growth in emissions exceeds the growth projections contained in the SIP. In addition, if the total growth exceeds the growth projections contained in the SIP, one or more of the contingency measures will be implemented to offset such growth, or the SIP will be revised as necessary to ensure continued maintenance of the standard.

The purpose of the addition of Regulation Number 7, Section II.E. is to provide sources with a process to obtain approval of an alternative emission control plan, compliance method, test method, or test procedure without waiting for EPA to approve of a site-specific SIP revision. The rule provides that any such alternative must be just as effective as the relevant regulatory provision, and that such effectiveness must be demonstrated using equally effective test methods and procedures. The changes to this section delegate the authority to the Division to approve of such alternatives. Since rulemaking is not required under Section II.E., the language allowing a source to assert that the relevant regulatory provision does not represent RACT has been omitted from this section. Such a change to the substantive requirements of Regulation Number 7 would require a rule change.

The rule revision proposed by the RAQC provided that alternative emissions control plans and compliance methods must be just as effective as those contained in the rule, but did not describe the test methods to be used to demonstrate such effectiveness. The Division proposed an alternative rule requiring such effectiveness to be demonstrated using test methods and procedures that are just as effective as those set out in the rule, or that have otherwise been approved by EPA. Such criteria for test methods and procedures are necessary in order to obtain EPA approval of this SIP revision. However, even without this language in the rule the Division would have required approved test methods and procedures in order to approve of proposed alternatives. The Division's alternative proposal provides the needed certainty in the most flexible manner possible.

Furthermore, the alternative proposed by the Division does not impose any new regulatory requirement. Instead, it merely establishes criteria for allowing persons' subject to the regulation to propose, in their discretion, an alternative means of complying with the existing regulatory requirements. Therefore, the alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity.

The rule revisions provide that no permit may be issued based on the provisions allowing for the creation of de minimis exemptions and the approval of alternative compliance plans without first revising the SIP unless EPA first approves of such regulatory revisions as part of the State Implementation Plan. The purpose of this condition is to address the possible disapproval of these revisions by EPA. In the event these changes are not approved by EPA, the remaining regulatory provisions of Regulation Number 7 will remain in full force and effect, and therefore, the EPA may approve of the maintenance plan and the redesignation request.

The revisions to Regulation Number 7 are procedural changes that are not intended to reduce air pollution.

For clarification, the Commission adopted these regulation revisions as follows:

REGULATION REVISION	OZONE SIP AND MAINTENANCE PLAN
Section I.A.1	Exists in Appendix C of the Ozone Maintenance Plan to become a part of that document approved March 21, 1996
Sections I.A.2., 3., 4.; Section II.D., II.E.	Adopted as subsequent regulation revisions to be submitted to the Governor and EPA separately and concurrently as a revision to the Ozone SIP (and Maintenance Plan)

The specific statutory authority to promulgate the rules necessary for redesignation is set out in §§ 25-7-105(1)(a)(I) and (2); -106(1)(a); -107 (1) and (2.5); and -301. The authority to adopt such rules includes the authority to adopt exceptions to the rules, and the process for applying for any such exemptions.

C. November 21, 1996 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

<u>Basis</u>

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally, because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Numbers 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3, Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

<u>Specific Statutory Authority</u>

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(I)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

<u>Purpose</u>

These revisions to Regulation Numbers 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

D. October 15, 1998 (Section II.F.)

The Gates Rubber Co. Site-specific Revision

The Gates Rubber Co. (Gates), by and through its attorney, submitted this Statement of Basis, Specific Statutory Authority and Purpose for amendments to Regulation Number 7, Control of Emissions of Volatile Organic Compounds.

Basis

Regulation Number 3 contains a certification and trading of emission reduction credits section (Section V), which sets forth the definitions and process for obtaining emission credits and using those credits. This section was amended to permit the use of emission reduction credits (ERC) to satisfy reasonably available control technology (RACT) requirements. The criteria for approval of ERC transactions specifies that they must involve like pollutants (for volatile organic compounds, the same degree of toxicity and photochemical reactivity), must be within the same nonattainment area, may not be used to satisfy Federal technology control requirements and may not be inconsistent with standards or regulations or to circumvent new source performance standards, best available control technology, lowest available emission rate technology controls or NESHAPs.

Regulation Number 7 sets forth CTG and RACT emission limitations, equipment requirements and work practices intended to control emission of volatile organic compounds (VOC) from new and existing stationary sources. The control measures specified in Regulation Number 7 are designed to reduce the ambient concentrations of ozone in ozone nonattainment areas and to maintain adequate air quality in other areas.

Specific Statutory Authority

The provisions of C.R.S. §§ 25-7-105 and 25-7-109 to 110 provide the specific statutory authority for the amendments to this regulation adopted by the Commission. The Commission has also adopted in compliance with C.R.S. § 24-4-103(4), this Statement of Basis, Specific Statutory Authority and Purpose.

Purpose

The purpose of this amendment to Regulation Number 7 is to establish a source specific rule for Gates to allow the use of emission reduction credits to satisfy the RACT requirements for VOC emissions pursuant to Regulation Number 7 for surface coatings operations not specifically listed in Section IX of Regulation Number 7. Regulation Number 3 provides specific authorization to use emission reduction credit transactions as an alternative compliance method to satisfy CTG and RACT requirements.

Specifically, the VOC certified emissions reduction credits to be used in this emission credit transaction in an amount up to 12 tons per year are from Coors Brewing Company pursuant to their emissions reduction credit Permit. The emission reduction credits will be used to satisfy the general requirements that all sources apply RACT. These emission reduction credits will be used by Gates so that Gates can use solvent-based surface coatings which contain VOCs periodically in lieu of the water-based coatings normally used on its 10 Cord coating line (S033, S034, and S035). These credits will allow Gates to meet RACT requirements without applying control technology to the 10 Cord line, other than the currently installed catalytic incinerator on the emissions from the drying oven from the fourth dip, which reduces those emissions by at least 90%. The relevant portion of Regulation Number 3, which applies to the Gates credit transaction is Section V.F., entitled “Criteria for Approval of all Transactions.” The first requirement is that the transaction involve like pollutants. In the present case, the emission credit transaction involves the exchange of VOC pollutants. Coors credits for methanol will be exchanged for m-pyrol. Exhaust from the catalytic incinerator, which contains unconverted toluene and xylene, is routed to the curing ovens of the other zones of the 10 Cord line, including the first zone. The Division has previously found that, excluding the emissions from the non-compliant coatings addressed in this rule, the 10 Cord line has met RACT standards. The use of the non-compliant coatings adds no HAPs to the Gates emissions. Other non-criteria reportable pollutants are present at well below APEN de minimis quantities under scenario 2, which is applicable to the 10 Cord line. Regulation Number 3 further requires that toxic or VOC pollutants involve the same degree of toxicity and photochemical reactivity or else a greater reduction may be required. Since these pollutants are both toxics and VOCs (except that m-pyrol is not a toxic), both have been addressed.

All of these compounds are commonly used in the surface coating industry with appropriate safeguards during their use. With respect to toxicity of the Gates compounds, m-pyrol is not listed as a toxic compound on either the federal or state lists. Methanol, the VOC in the Coors credit, is a Bin C HAP. Because the m-pyrol in the non-compliant coatings is not a HAP, the Gates VOCs have equal or lower toxicity than those being purchased from Coors. Therefore, HAP emissions will be reduced in the airshed.

The photochemical reactivities of VOCs are important because of their impact on the ozone formation process in an airshed. The Air Pollution Control Division relied upon the work of Dr. William P.L. Carter, Professor at the University of California, whose article entitled “Development of Ozone Reactivity Scales for Volatile Organic Compounds” describes relative photochemical reactivity scales and comparisons. Dr. Carter notes that there are a number of ways to quantify VOC reactivities, but the most relevant measure of VOC effects on ozone is the actual change in ozone formation in an airshed. This results from changing the emissions of the VOC in that airshed which depends not only on how rapidly the VOC reacts and the nature of its atmospheric reaction mechanism, but also the nature of the airshed where it is emitted, including the effects of other pollutants which are present.

Dr. Carter further states that the VOC effect on ozone in the atmosphere can only be estimated using computer airshed models. The effect of changing the emissions of a given VOC on ozone formation in a particular episode will, in general, depend on the magnitude of the emissions change and on whether the VOC is being added to, subtracted from, or replacing a portion of the base case emissions.

Dr. Carter's derived relative reactivity scale includes reactive organic gases whose indices for maximum incremental reactivity (MIR) range from 0.004 to 6.5. The MIR values were updated in 1997. The VOCs and their respective MIR involved with this exchange are as follows:

Methanol	0.16
m-Pyrol	0.57

The pending emission credits of VOCs being used in the proposed emissions credit transaction are for methanol. The VOCs emitted from uncontrolled use of solvent-based coatings at Gates are from m-pyrol. Regulation Number 3 provides that if the VOCs are not of the same photochemical reactivity, a greater offset may be required. The Commission required that, based on a past ERC trade for Pioneer Metal Finishing, that methanol credits in a 1.1:1 offset ratio be exchanged for toluene and xylenes. Here, however, the Commission finds that m-pyrol and methanol have similar photochemical reactivities, so no offset will be required.

The second requirement states that the transaction must not result in an increased concentration, at the point of maximum impact of hazardous air pollutants. This provision was derived from the EPA Emissions Trading Policy Statement and referred to NESHAP requirements involved in bubble transactions. If this provision is interpreted to apply generally to a facility which is limited by an existing permit to some level of VOC emissions on a twenty-four-hour basis, any additional VOCs allowed pursuant to an emission transaction would by its application increase the concentration of VOCs at the maximum point of impact. Since it appears to have been intended to limit NESHAP offsets in bubble transactions, and no NESHAPs are applicable in the Gates transaction, and recognizing the earlier action of the Commission in approving the use of ERC transactions to satisfy CTG requirements and in approving a previous ERC transaction for Pioneer Metal Finishing, the Commission determined that this requirement should not apply to this transaction.

The next requirement states that no transaction may be approved which is inconsistent with any standard established by the Federal Act, the state Air Quality Control Act or the regulations promulgated under either, or to circumvent NSPS requirements or BACT or LAER, although the Commission may approve a transaction using a certified emission reduction credit in lieu of a specified CTG method or RACT. The emissions involved in this transaction at Gates are not subject to NSPS, BACT, or LAER. Regulation Number 7 applies only RACT to the Gates operations involved. Regulation Number 3 clearly permits the use of emission reduction credits to satisfy RACT.

The emission must involve sources which are located within the same nonattainment area. In the present case, both Gates, whose operations are located at 900 S. Broadway, Denver, Colorado, who is proposing to use the credits, and the source of the credits, Verticel, whose operations were located at 4607 South Windermere Street, Englewood, Colorado, are located in the Denver nonattainment area, less than five miles apart.

The next requirement prohibits the use of emission reduction credits to meet applicable technology-based requirements for new sources, such as NSPS, BACT, or LAER. As stated, the Gates operations involved in this transaction are not subject to NSPS, BACT, or LAER or any other technology-based requirement except for RACT requirements for which an ERC transaction may be used to satisfy such requirements.

The next requirement states that VOC trades will be considered equal in ambient effect where the trade is a pound for pound trade in the same control strategy demonstration area. It appears that this requirement, which was taken from the EPA Emissions Trading Policy Statement, made the assumption that the “pound for pound” trend would have an equal impact on the ambient environment, with respect to ozone. Since there was no independent photochemical reactivity equivalency requirement in the 1986 Policy Statement, this requirement appears to be redundant with the requirement for insuring the same degree of photochemical reactivity among traded pollutants.

For VOC trades involving surface coating, the requirements state that emissions must be calculated on a solids-applied basis and must specify the maximum time period over which the emissions may be averaged, not to exceed 24 hours. The proposed emissions credit transaction is based on a 24-hour period. With respect to the solids-applied basis calculation, this transaction will be calculated on the basis of the pounds of VOCs from uncontrolled solvent-based coatings.

The emissions credit transaction will require a SIP revision. The source specific rule for Gates will be forwarded to EPA for approval. The state emissions permit for Gates pursuant to the emissions credit transaction will be state effective (but not federally effective) until the SIP revision is approved by EPA.

Gates proposed the following VOC emissions limitation in its state permit taking into consideration the pounds per year VOC emissions allowed by this emissions credit transaction:

1. A daily maximum limitation of 400 lbs. of VOC emissions from uncontrolled solvent-based surface coatings, calculated on a monthly basis for compliance purposes. Calculations will be performed by the 30th of the following month.

2. An annual limitation of no more than 24,000 lbs. (12 tons) of VOC emissions from uncontrolled solvent-based surface coatings.

Gates proposes to calculate the annual total VOC limitation on a rolling 12-month basis. Gates further proposes to keep monthly totals of non-compliant surface coatings used and to calculate daily usage based on monthly usage divided by the number of days’ non-compliant surface coatings were used. Records of usages and calculations will be kept and produced at the Division's request.

This source-specific rule has a negligible or no effect upon the other provisions of the ozone SIP.

It is contemplated that a State construction permit will be issued to Gates upon final approval by the Commission. Should the approval come after the issuance of Gates' Title V operating permit, the terms of the construction permit will be added to the operating permit.

E. January 11, 2001 (Sections III.C., IX.L.2.c.(1), and X.D.2. through XI.A.3.)

Readoption of Changes to Regulation Number 7 that were not printed in the regulation or the Colorado Code of Regulations.

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Basis

During a review of the version of Regulation Number 7 adopted by the Air Quality Control Commission and the version of Regulation Number 7 published in the Colorado Code of Regulations, several significant discrepancies have been identified. This rule making will clarify the Commission's intent to adopt the following revisions to Regulation Number 7:

1. Section III.C regarding General Requirements for Storage of Volatile Organic Compounds omits the following revision:

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

2. Section IX.L.2.c.(i) contains discrepancies in reference to the permit number of Coors Brewing Company Emissions Reduction Credit Permit issued on July 25, 1994.

3. Section X.D.2. through Section XI.A.3. was omitted from the CCR as published in the current version of Regulation Number 7.

Specific Statutory Authority

Sections 25-7-109, C.R.S. (1997) authorize the Commission to adopt emission control regulations.

Purpose

Re-adoption of the proposed rule will eliminate the discrepancies between the Commission's adopted provisions within Regulation Number 7 and those contained within the Colorado Code of Regulations. Adoption of the amendments will benefit the regulated community by providing sources with consistent information.

F. November 20, 2003 (Sections I.A.2. through I.A.4., II.D. and II.E.)

The Commission repealed the provisions establishing a procedure for granting exemptions for de minimis sources, and the procedure for approving alternative compliance plans without source-specific SIP revisions. The Commission had adopted the repealed provisions in March 1996, but had delayed the effective date pending EPA approval through the SIP revision process. Earlier this year, EPA informed the Commission of its intent to disapprove the provisions unless they were withdrawn. Thus, the provisions that are the subject of this rulemaking action never took effect. The Commission hereby repeals such provisions in order to avoid disapproval of the earlier SIP submittal, and to remove extraneous provisions from Regulation Number 7. Such repeal is required in order to comply with federal requirements, and is not otherwise more stringent than the requirements of the federal act.

Sections 25-7-105(1)(a)(I) and 25-7-301 authorize the Commission to adopt and revise a comprehensive SIP, and to regulate emissions from stationary sources, as necessary to maintain the national ambient air quality standard for ozone in accordance with the federal act.

G. March 12, 2004 (Sections I.A, I.B., XII., and XVI.)

The March 2004 revisions were adopted in conjunction with the Early Action Compact Ozone Action Plan, which is a SIP revision for attainment of the 8-hour ozone standard by December 31, 2007. The Commission adopted four new control measures in Regulation Number 7 to reduce emissions of volatile organic compounds (VOC). The control measures require the installation of air pollution control technology to control: (1) VOC emissions from condensate operation at oil and gas (E&P) facilities; (2) emissions from stationary and portable reciprocating internal combustion engines; (3) certain VOC emissions from gas-processing plants; and, (4) emissions from dehydrators at oil and gas operations.

The new requirements in Sections XII., and XVI. apply to a larger geographic area than the pre-existing requirements of Regulation Number 7, as set out in Section I.A. of the rule. The reference to the “Denver Metro Attainment Maintenance Area”, which is not a defined term, in Section I.A was changed to refer to the “Denver 1-hour ozone attainment/maintenance area”, which is defined in the Ambient Air Quality Standards Rule. Similarly, the reference to the “Denver Metropolitan Nonattainment Area Ozone Maintenance State Implementation Plan” was changed to the “Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area,” which is the correct name of the document submitted to EPA in May 2001.

Regarding VOC emissions from condensate operations, the Commission has determined that an overall reduction of 47.5% VOCs is required of each E&P operation so as to meet the requirements of the SIP. Further the Commission decided not to take a unit-by-unit approach, but rather, the amendments take a more flexible approach to regulating such emissions by requiring sources that have filed, or were required to file, APENs to choose emission controls and locations for applying those controls. This approach also minimizes the risk that sources may reconfigure tanks to avoid implementing the regulation.

Section XII.A.6. provides an exemption for owners and operators with less than 30 tpy of flash emissions subject to APEN reporting requirements. Regulation Number 7 previously included more general exemptions for emissions from condensate operations, but such pre-existing exemptions should have been repealed as part of this revision to Regulation Number 7. To the extent any pre-existing exemption for condensate operations remains, such pre-existing exemption shall not be construed to supersede the requirements of Section XII.

The rule also requires annual reports describing how E&P sources will achieve the requisite emission reductions. Such reports are necessary so that the Division can determine whether or not the emission reductions are being achieved.

Section XII.B. of Regulation Number 7 is required to ensure that existing and new natural gas processing plants employ air pollution control technology to control emissions from leaking equipment, and atmospheric condensate storage tanks (and tank batteries). The Commission is specifically requiring a leak detection and repair (LDAR) program for all gas plants, according to the provisions of 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the affected facility. This is necessary to ensure these large facilities are well controlled and VOC emissions minimized.

Section XII. C. pertains to control of VOC emissions from natural gas dehydration operations. The Commission determined that, in order to meet the requirements of the SIP, emissions must be reduced from all dehydration operations located in the 8-hour Ozone Control Area if such operations produce emissions above the minimum threshold specified in the rule. Further the Commission decided that flexibility should be allowed in how emissions are reduced, so several options are listed from which a source owner or operator may choose. If other equally effective measures or control devices are available, the Division may, on a case-by-case basis, approve the use of such alternatives.

Similarly, Section XVI. establishes controls for reciprocating internal combustion engines. Both “lean” and “rich” burn engines are addressed and though the Commission has specified the default control technology to be applied to each engine type, the Division is allowed to approve alternative technology if a demonstration can be made that the alternative is at least as effective as the listed device in reducing VOC emissions. Parties to the rulemaking hearing provided evidence that suitable, cost-effective control equipment may not be available for some existing engines. The rule adopted by the Commission includes an exemption for lean burn engines if the owner demonstrates that such emissions controls would cost $5,000 or more per ton of VOC removed. In calculating such costs, the Division shall use an appropriate amortization period and current discount rate. The Commission directs the Division to further investigate the question of whether controls are available and suitable for lean burn engines, and to recommend any revisions necessary for the regulation applicable to such engines. New engines locating in the control area must comply with the requirements effective June 1, 2004, but existing engines have until May 1, 2005 to come into compliance. Since the rule provides an exemption for existing engines that cannot be controlled for less than $5,000 per ton, the rule must make the distinction between new and existing engines so that engines will not be moved into the area during prior to May 2005 and subsequently apply for such an exemption.

The Commission recognizes that, at this point in time, the controls required by the rule amendments constitute Reasonably Available Control Technology (RACT), at a minimum, and in some cases, the controls mandated by this regulation may, in fact, constitute Best Available Control Technology (BACT). This means that this regulation shall not be used: (a) to preclude a source from asserting that one of the controls mandated herein constitutes BACT or Lowest Achievable Emissions Rate (LAER) for a new source or major modification, (b) require the Division or Commission to mandate different control technologies as BACT, or (c) preclude the Division or Commission from requiring additional or more stringent air pollution control technologies as necessary or appropriate to comply with applicable BACT or LAER requirements for new sources and major modifications.

By its terms, the New Source Performance Standard (NSPS) applicable to leaking equipment at onshore natural gas processing plants (40 CFR Part 60, Subpart KKK) applies to “affected facilities” and “process units” at such facilities as those terms are defined in the standard. In general, plants that were constructed prior to January 20, 1984 are exempt from the standard, unless subsequently modified or reconstructed, or newly constructed after that date. Since process units at a single gas plant can be distinct, certain gas plants may contain equipment that is not presently subject to the NSPS because of its date of construction. The control requirement in Section XII.B. would extend leak detection and repair program requirements to such equipment.

The statutory authority for the revisions to regulation Number 7 is set out in Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The March 2004 revisions to Regulation Number 7 are based on reasonably available, validated, reviewed, and sound scientific methodologies. All validated, reviewed and sound scientific methodologies and information made available by interested parties has been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution. The Commission chose the most cost-effective mix of control strategies available to comply with the 8-hour ozone NAAQS. Where possible, the regulations provide the regulated community with flexibility to achieve the necessary reductions. The Commission chose the regulatory alternative that will maximize the air quality benefits in the most cost-effective manner.

H. December 16, 2004 (Sections I.A., II.A., XII. and XVI.)

The December 2004 revisions were adopted to respond to U.S. EPA comments on the Ozone Action Plan the Commission adopted in March 2004. EPA required the rule revision in order to make the control measures incorporated into the State Implementation Plan practically enforceable as required by the federal Clean Air Act. The Federal Act requires all of the regulatory provisions adopted in this rulemaking action, and none of the provisions are more stringent than the requirements of the federal act.

The revised rule includes a process for obtaining emission reduction credit for pollution prevention measures. In order to qualify for an emission reduction credit, a pollution prevention measures must, among other things, be included in a permit even if it does not involve the construction of an air pollution source and would not otherwise trigger a requirement for a permit. The revisions to the regulation do not, however, create a requirement for sources to obtain a permit for pollution prevention measures for which the source will not take emissions reduction credit.

The Commission has the statutory authority to adopt the revisions pursuant to Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The control measures necessary to achieve the 8-hour ozone standard were adopted in March 2004. The December 2004 rule changes do not impose new emission control requirements or emission reduction requirements on industry. Instead, the December 2004 rule revisions are intended to make the previously adopted requirements more enforceable, and to make sure that the requisite emission reductions occur during the ozone season when they are needed. Thus, the December 2004 are administrative in nature in that they are intended to assist with the administration and enforcement of the previously adopted controls. The Commission recognizes that the December 2004 rule amendments impose additional recordkeeping and reporting requirements, and therefore costs, on the regulated community. The changes, however, are not intended to achieve further reduction in emissions of volatile organic compounds beyond the reduction requirements adopted in March 2004. They are instead intended to make the March 2004 revisions fully enforceable and acceptable to EPA. Since the December 2004 rule changes are administrative in nature, the requirements of Section 25-7-110.8 C.R.S. do not apply.

I. December 17, 2006 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

<u>Basis</u>

Regulation Number 7, Section XII imposes emission control requirements on oil and gas condensate tanks located in Adams, Arapahoe, Boulder, Douglas and Jefferson Counties, the Cities and Counties of Broomfield and Denver and parts of Larimer and Weld Counties (“8-Hour Ozone Control Area”). The condensate tank requirements, along with other requirements applicable to oil and gas operations and natural gas fired reciprocating internal combustion engines, were initially promulgated in March 2004, and later revised in December 2004, in connection with an Early Action Compact Ozone Action Plan (“EAC”) entered into between the State of Colorado and the United States Environmental Protection Agency. The purpose of the EAC is to prevent exceedances of the 8-Hour Ozone Standard and avoid a nonattainment designation for the area. Pursuant to the EAC, Colorado committed to limiting Volatile Organic Compound (“VOC”) emissions from condensate tanks located in the 8-Hour Ozone Control Area to 91.3 tons per day (“TPD”) as of May 1, 2007 and 100.9 TPD as of May 1, 2012. Because of unanticipated growth of condensate tank emissions since 2004, the control requirements for condensate tanks adopted during the 2004 rulemaking are insufficient to meet these daily emission numbers. The current revisions require a greater level of control of condensate tank emissions in the 8-Hour Ozone Control Area in order to meet the commitments set forth in the EAC and to prevent future exceedances of the 8-Hour Ozone Standard.

These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Section, 25-7-105(1)(a), C.R.S., which gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of a comprehensive state implementation plan that will assure attainment of national ambient air quality standards. Additional authority for these revisions is set forth in Sections, 25-7-106 and 25-7-109, which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to specified areas within the state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XII. were adopted in order to meet the commitments with respect to condensate tank emissions set forth in the Early Action Compact Ozone Action Plan entered into between the State of Colorado and U.S. EPA, prevent exceedances of the 8-Hour Ozone Standard, and simplify recordkeeping and reporting requirements. To accomplish these goals, the revised regulation raises the system-wide control requirements for the ozone season from the current 47.5% to 75% commencing in 2007 and 78% in 2012. While the rule establishes a higher percentage reduction in 2012 the Commission recognizes that given the uncertainty of emissions growth over the next 6 years, this reduction requirement may be too high and may need to be revisited as the 2012 deadline approaches. For the non-ozone season the required reduction has been raised from 38% to 60% commencing October 2007, and 70% commencing January 1, 2008. Determination of compliance during the ozone season under the revisions will be on a weekly basis instead of a daily basis, in recognition of the fact that condensate production is not typically measured on a daily basis. Under the previous version of the Rule, production could be tracked on something greater than a daily basis and the total divided by the number of days to obtain a daily number. As such, the prior rule did not truly give a daily average and thus the move to a weekly average is of little substance. Apart from this change, calculation of emissions for compliance purposes will remain the same as under the previous version of the rule.

In addition to raising the system-wide reduction requirements, the current rule adds significant new monitoring, record-keeping and reporting requirements, and a “backstop” threshold requirement to have emission controls on all condensate storage tanks with uncontrolled actual emissions of 20 tpy or more of VOC flash emission, as a state-only requirement within the EAC area pursuant to Section XVII.C.1. of Regulation Number 7. Owners and operators will continue to keep a spreadsheet that tracks emission reductions and submit an Annual Report as required under the previous version of the rule. Owners and operators are now also required to submit a semi-annual report on November 30 of each year detailing their emissions during the preceding ozone season. Additional record keeping has been added so as to require that a weekly checklist be maintained detailing inspections of control devices. This checklist will assist operators in the inspection and maintenance practice and provide a record that proper inspections have been done. If the inspections show a problem with the control device, the owner or operator will be required to notify the Division of problems on a monthly basis. This requirement will allow the Division to track problems on a timelier basis and ensure compliance with the rule. Finally, a provision has been added to require owners or operators to submit a list of all their controlled tanks on April 30 of each year and notify the Division monthly during ozone season if the control status of any tank changes.

J. December 17, 2006 (Sections I.A.1.b. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted these state-only provisions as a means of reducing air emissions from oil and gas operations throughout Colorado. Due to the large growth in oil and gas production in a number of regions of the state emissions from oil and gas operations have rapidly increased over the past few years and are expected to increase further in the foreseeable future. These revisions are a proactive measure designed to eliminate air emissions that could threaten attainment of ambient air quality standards and adversely affect visibility in Class I Areas. These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-106 and 25-7-109 of the Colorado Air Pollution Prevention and Control Act (“Act”), which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Additional authority is set forth in Section 25-7-105.1, which allows the Commission to adopt state-only standards. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to the entire state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XVII. were adopted in order to reduce air emissions from oil and gas operations and natural gas fired reciprocating internal combustion engines in Colorado. These revisions constitute a forward-looking approach to deal with a rapidly growing source of air emissions, and are designed to reduce the possibility of future problems with respect to the attainment of National Ambient Air Quality Standards and state and federal Class I Area visibility goals. Since the requirements are not mandated under federal law and are not currently necessary to meet National Ambient Air Quality Standards they are being adopted as a state-only requirement in accordance with the Act and as provided for under the Federal Clean Air Act.

These revisions establish emission control requirements for condensate storage tanks, glycol dehydrators and natural gas fired reciprocating internal combustion engines in Colorado. These provisions require that condensate tank and dehydrator controls meet a 95% percent control efficiency. As in the EAC Area, this requirement does not contemplate stack testing in order to verify the control efficiency. The insertion of the word average allows operators some downtime without a violation occurring so long as the downtime does not result in an average control efficiency of less than 95% considering the actual engineered control efficiency. For the purposes of XVII.C.4.b. observed operation of flare auto-igniters can include telemetric monitoring systems, physical on-site function tests or auditory confirmation of the auto-igniter function.

The requirements applicable to glycol dehydrators mirror the requirements applicable in the 8-Hour Ozone Control Area set forth in Section XII, and should be interpreted consistently with those provisions notwithstanding the addition of clarifying language. For example, language has been added clarifying that grouping of dehydrators is limited to dehydrators at a single site. Similarly, the word “production” has been added to the definition of condensate tank to clarify that the requirements, as within the EAC, do not apply to produced water tanks.

Determination of whether a condensate tank's emissions are at or above the threshold is based on the emissions from the tank during the preceding twelve-month period. If a tank has been in service for less than twelve months, applicability shall be based on uncontrolled actual emissions over the service period of the tank multiplied out to twelve months. Accordingly, if a tank has been in service for three months, applicability of the control requirements will be based on the uncontrolled actual emissions from the tank for those three months multiplied by four. If emissions from a controlled tank decrease, operators may remove the controls when emissions from the previous twelve-month period falls below the applicable threshold. Operators will remain responsible, however, for controlling a tank if a subsequent emission increase results in emissions being over the applicable threshold during the preceding twelve months. For tanks serving newly drilled, recompleted or restimulated wells (including refrac'd wells) the owner or operator will have 90 days to determine anticipated production and, if necessary install a control device. In determining anticipated production, the owner or operator may use an appropriate decline factor to determine expected emissions over the first 12 months after the new drilling, recompletion or re-stimulation. If the owner or operator determines that emissions will be below the 20 tpy threshold following the new drilling, recompletion or restimulation, the owner or operator shall notify the Division of this determination.

Certain differences with the requirements applicable to the 8-Hour Ozone Control Area have been included in order to provide greater flexibility to operators in other areas of the state and in light of the fact that the regulation represents a proactive attempt to avoid future impacts from oil and gas emissions. Specifically, the standards for obtaining approval of an alternative pollution control device have been relaxed to promote innovative control strategies. Additionally, a provision has been added to allow an extension of the control requirement deadlines at the Division's discretion for good cause shown. This provision allows the Division to extend a deadline where shortages of control equipment, and crews may prevent an operator from meeting the deadlines, particularly in areas where access is limited by the weather or other issues. With respect to Section VII.B.1.c. of the General Provisions, the Commission has determined that as a general rule during normal operations no emissions should be visible from the air pollution control equipment.

Normal operations include reasonably foreseeable fluctuations in emissions from the condensate tank, including the fluctuations that occur during a separator dump. However, a transient (lasting less than 10 seconds) "puff" of smoke when the main burner ignites or shuts down would not be considered a violation of the "no visible emission" standard. Finally, a provision has been included that exempts units' subject to the rule if such units are also subject to a control standard under the MACT, BACT or NSPS Programs. This exception is of most importance for new and newly relocated engines that may become subject to a currently pending NSPS Standard under Subpart JJJJ.

The engine provisions only apply to engines that are constructed or relocated into Colorado after the applicability date and do not impose requirements on units that are currently located in the state.

The Commission recognizes that the adopted emission control requirements represent a first step in addressing rapidly growing emissions from oil and gas operations throughout the state. Accordingly, the Commission directs the Division to provide an annual update on emission growth trends, environmental impacts, modeling and monitoring efforts, the adequacy of emission controls to protect the NAAQS and the health impacts of emissions from the oil and gas sector.

K. December 12, 2008 (Title, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions throughout Regulation Number 7 to address ozone formation in the 8-Hour Ozone Nonattainment Area (NAA), including the 9-county Denver Metropolitan Area and North Front Range (DMA/NFR) NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions are necessary to ensure attainment with the current 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) set at 0.08 parts per million (ppm), and to achieve additional ozone reductions in light of both the new ozone NAAQS set at 0.075 ppm and the Governor's July 27, 2007 directive to proactively and pragmatically reduce ozone levels.

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the area in question expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-hour Ozone NAAQS of 0.08 ppm for ground level ozone. The DMA/NFR includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties. This area is now known as the DMA/NFR NAA.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a revision to the State Implementation Plan (SIP) to the EPA no later than June 30, 2009 that demonstrates attainment of the 8-Hour Ozone NAAQS no later than 2010. The Commission has adopted an Attainment Plan that satisfies this requirement. The Attainment Plan demonstrates attainment with no additional control measures.

Photochemical grid dispersion modeling indicates that without further emission controls, Colorado will attain the 8-hour standard by 2010. The dispersion modeling reflects that Colorado would attain the standard by a narrow margin. Photochemical dispersion modeling analysis is the primary tool used to assess present and future air quality trends, and is required for EPA to approve the state attainment demonstration in the SIP.

In addition, pursuant to EPA guidance, if modeling results indicate that the highest ozone levels will fall between 0.082 and 0.087 ppm, Colorado must conduct a "weight of evidence" analysis and other supplemental analyses in order to corroborate the modeling results. Colorado's model results are within this range, and thus the state has conducted this analysis. The analysis supports the conclusion that Colorado will attain the standard by 2010.

The Commission is also adopting State-only revisions to Regulation Number 7 to further address ozone formation in the DMA/NFR NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions help Colorado make progress toward eventual compliance with the new ozone NAAQS set at 0.075 ppm as well as the Governor's directive to proactively and pragmatically reduce ozone levels.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act ("Act"), C.R.S. § 25-7-101, et seq., specifically, C.R.S. §25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and § 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

These revisions to Regulation Number 7 are part of an overall ozone reduction strategy. The Commission intends that this overall ozone reduction strategy accomplishes six objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the Ozone NAA and across the state, B) revise the control requirements for condensate tanks by a refined system-wide control strategy in the Ozone NAA, C) expand VOC RACT requirements for listed source categories for 100 tpy sources such that all Ozone NAAs are subject to Regulation Number 7's RACT requirements, D) clarify how the RACT requirements in Regulation Numbers 3 and 7 interact in the Ozone NAA, E) improve the Division's inventory of condensate emissions and other relevant sources in the NAA; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

In support of objectives A-D and F, the Commission adopts these revisions to Regulation Number 7 to revise condensate tank regulations, set pneumatic controller regulations, expand RACT applicability and make associated corrections (Regulation Number 7, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F).

In the course of this proceeding, the Division and certain parties supported a compromise proposal regarding the control of condensate tanks. The Commission finds this proposal to be appropriate with certain changes noted herein. The Commission is requiring an increase from 75% to 81% control on a system-wide basis in 2009; to 85% control on a system-wide basis in 2010; and to 90% control on a system-wide basis in 2011 in the 8-Hour Ozone NAA. The Commission is adopting new VOC controls for pneumatic controllers in the 8-Hour Ozone NAA in Regulation Number 7, Section XVIII.

These system-wide control percentages achieve significant ozone precursor reductions in 2009, 2010 and 2011, with emphasis on significant VOC emissions reductions in 2010, during the monitoring period for the attainment demonstration. These revisions will help to ensure that the non-attainment area realizes the necessary reductions during the 2010 attainment year. Further, these revisions are an important step in putting the State on a path towards attaining the 2008 8-Hour ozone standard. A number of parties including the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization supported this proposal to secure VOC reductions from this source at these levels and according to this schedule. The system-wide approach has been approved by the Commission in the past, as well as by EPA in revisions to the State Implementation Plan. The Commission decided to defer decision making on the implementation of a 95% system-wide level of control, given concerns regarding the notable incremental cost associated with control to the equivalent of 2 tpy tanks as well as concerns regarding the flexibility intended to be afforded by a system-wide approach. Tank operators also expressed concern about the loss of incentive to over-control their systems to meet the standard, and the difficulty for small operators to control at the 95% system-wide level at this time.

The proposed control percentages continue to afford flexibility in operations to condensate tank operators, while ensuring attainment of the standard by 2010. Therefore, the Commission is deferring further control for future modeling, air quality analysis, and/or administrative review, whether to control this source in the future at the 95% system-wide control level or through some other approach for purposes of the 2008 8-Hour standard.

The provisions of the compromise proposal, including the commensurate emissions reductions, support the State Implementation Plan's ability to assure attainment and maintenance of the 1997 8-Hour Ozone NAAQS. Inclusion of these provisions enhances the Weight of Evidence demonstration supporting attainment by 2010 pursuant to this State Implementation Plan. The Commission recognizes parties subject to the compromise Regulation Number 7 provisions for condensate tank system-wide emissions reductions concur that these provisions are appropriate for inclusion in the State Implementation Plan.

Further the Commission intends to expand the applicability of RACT requirements to existing, new and modified sources in Ozone NAAs outside of the historic one-hour Ozone NAA or attainment/maintenance area (Regulation Number 7, Sections I and II). The Commission further intends to clarify how the control technology requirements of Regulation Number 7 interact with Regulation 3, Part B, Section II.D.2.

Finally, the Commission intends to make grammatical, typographical, formatting revisions, and other editing revisions throughout Regulation Number 7.

Condensate Tank Emissions Control

Condensate storage tank control requirements in Regulation Number 7, Section XII. are revised by reorganizing the rule, adding/revising definitions, adding monitoring requirements, revising recordkeeping and reporting requirements, and setting additional control requirements for tanks. The current requirements are reorganized by specifying applicability, definitions, general provisions, emissions controls, monitoring, and recordkeeping and reporting sections. The terms new, existing, modified/modification, auto-igniter, and surveillance system were defined.

Tanks serving newly drilled, recompleted or stimulated wells are required to employ air pollution control equipment during the first 90 days of production. After the first 90 calendar days, the control device may be removed. This requirement is designed to address the fact that production, and thus emissions, is at their greatest during the period immediately after drilling, recompletion or stimulation, and the fact that the actual production/emission level is not known prior to drilling, recompletion or stimulation. By requiring controls on all tanks serving newly drilled, recompleted or stimulated wells, the proposed rule significantly reduces emissions during the initial period, while allowing owners and operators to remove control devices afterward, as part of the overall system-wide control regime. All tanks over 2 tpy must participate in the overall system-wide program. Furthermore, since Regulation Number 7's system-wide program is essentially RACT for condensate tanks in the NAA, new and modified 2 tpy or greater condensate tanks (affected by Regulation Number 3 RACT) may also move their control devices after the first 90 days when participating in the overall system-wide control regime, as long as the overall system-wide requirements are being met. Such flexibility is provided as to avoid two regulatory programs: one for tanks that might never be allowed to move their control devices under Regulation Number 3 RACT and one for tanks that would be allowed the flexibility under a system-wide program. Finally, it is the intent of this rule that sources may use their 2 tpy or greater "modified" tanks emissions (i.e., during those tanks' first 90 days of production) in the source's overall system wide calculation. After 90 days, sources must include – whether controlled or otherwise - the 2 tpy or greater "modified" tanks in the overall system-wide calculation. In the case of modified tanks that fall below 2 tpy, it is not the intent of the commission for sources to include these less than 2 tpy tanks in any system-wide calculation. However, sources may use the less than 2 tpy controlled tanks, if necessary to demonstrate system-wide compliance.

The Commission is requiring the installation and operation of auto-igniters for each combustion device. In many cases, condensate tanks are remotely located and unmanned. Auto-igniters will provide greater assurance that the control devices are functioning, under these circumstances. Auto-igniters may be relied on to identify when the pilot is not lit and attempt to relight it, and ensure control operation. The Commission is also requiring surveillance on batteries with uncontrolled emissions greater than 100 tpy. Operators must use surveillance to document the duration of time when the pilot is not lit, and to discover if repairs are necessary to ensure proper control operation. The Commission is targeting this size of battery in order to strike a balance between the need to more carefully monitor performance among the largest batteries, the cost associated with surveillance and the division's capacity to manage the information. The Commission acknowledges that three well operators, Encana, Anadarko and Noble Energy, have agreed to participate with the Division in a pilot program regarding the implementation of electronic surveillance systems.

With regard to recordkeeping and reporting requirements, operators will still record estimated emissions each week (as part of the current Regulation Number 7 requirements) and will report this information to the Division semi-annually. In addition, the Division has revised these requirements so that sources now must keep monthly records throughout the year and provide any of those records within 5 business days of a division request. Further, operators may only use a Division-approved spreadsheet to submit emissions records. Further, a responsible official must now certify the accuracy of the data in the semi-annual reports. This level of recordkeeping and reporting will allow the Division greater capacity to verify compliance and additional availability to work with sources (especially smaller operators). The Commission intends that record-keeping and reporting requirements for surveillance apply only to tanks with uncontrolled emissions greater than 100 tpy.

Controls on 2 Tons Per Year Tanks and Lower

The Commission intends that substantial emissions reductions be achieved from condensate storage tanks and that industry retain the flexibility to decide which tanks to control in order to achieve those reductions. The rule has been revised to subject any condensate storage tank to this rule in the Applicability Section, but stipulates in the Emission Control Section that in order to determine the appropriate system-wide emissions reductions, only two tons per year tanks be considered. In doing this, the Commission intends that tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year or more be considered in determining compliance with the system-wide emissions reductions for the specific ozone non-attainment or attainment maintenance area, and that industry have the flexibility to control smaller tanks in those specific ozone non-attainment or attainment maintenance areas if needed in order to meet the applicable system-wide emissions reductions. For example, if a company owns 20 tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year in a specific ozone non-attainment area, and 15 tanks that emit less than two tons per year, the company would determine its required emission reductions of the production through the 20 two tpy tanks, but be able to control any of the 15 additional less than 2 tpy tanks in order to comply with the system-wide emissions reduction or maintain the desired over control as buffer. However, all tanks controlled in order to comply with the system-wide emissions reduction standard must have filed an APEN and obtained a valid permit in order to be considered as part of the compliance demonstration.

Calendar Weekly and Calendar Monthly Records and Reports

The Commission intends that records and associated reports demonstrating compliance with the weekly emission reduction requirement shall start with the calendar week containing May 1st and end with the calendar week containing September 30th, or other specified dates in the rule. A calendar week begins midnight Sunday morning and ends the following Saturday evening at midnight. Thus, where May 1st falls on any day other than Sunday, the calendar week of May 1st begins on midnight of the preceding Sunday morning. Similarly, the weekly emission reduction requirement applies to the full calendar week that includes September 30th.

So, if September 30th falls somewhere in the middle of a calendar week, the emissions reduction requirement applies to that calendar week in full, beginning midnight Sunday morning and ending the following Saturday evening at midnight.

Consequently, calendar monthly records and associated reports demonstrating compliance with the monthly emission reduction requirement shall apply to midnight the morning of day 1 through midnight the evening of the last day of each specific calendar month.

The Commission intentionally broadened the definition of surveillance to provide that: 1) electronic surveillance is not specifically required, and other means to gather information from remote locations is allowed; and 2) data only had to be gathered on a daily basis. The Commission intends that currently required surveillance need only monitor combustion device flame presence or temperature once every day, in order to balance the need to gather adequate data on combustion device operation with the amount of data to be gathered, handled and processed. The Commission believes this is a fair approach considering that only the largest atmospheric condensate storage tanks (those with actual uncontrolled volatile organic compound emissions equal to or greater than 100 tons per year) are subject to this surveillance requirement.

Finally, the Commission intends that the monitoring be completed to ensure compliance, and has determined that failing to monitor as required, losing monitoring data, and failing to maintain monitoring data should be treated similarly to recordkeeping requirements. Thus, these actions “may be treated by the Division as if the data were not collected.”

The Commission intends that system-wide emissions control requirements apply to each specific ozone non-attainment or attainment maintenance area and not collectively to all ozone non-attainment or attainment maintenance areas state-wide. This means that the system-wide emissions control requirements apply specifically to the Ozone Control Area (a.k.a. the Denver Metropolitan Area/North Front Range Ozone Control Area), separately from any future designated ozone non-attainment area. Each new ozone non-attainment area designated in the future shall be subject to the system-wide control requirements by themselves. This is needed to ensure that necessary controls are achieved and maintained in each ozone non-attainment or attainment maintenance area, and that these controls are not removed and offset by system-wide controls in some other ozone non-attainment area.

Pneumatics Emissions Control

This revision establishes new VOC controls for pneumatic controllers in the 8-hour Ozone NAA in Regulation Number 7, Section XVIII. Pneumatic controllers are widely used in the oil and gas industry to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature. Pneumatic controllers of interest are instruments that are actuated using natural gas pressure (of which some natural gas may be bled to the atmosphere from the pneumatic controller and some may be vented from the associated valve). Natural gas-actuated pressure relief devices are not intended to be covered by this rule. There are high-bleed controllers designed to emit more than six standard cubic feet of gas per hour (scfh) to the atmosphere, and low-bleed controllers that emit six scfh or less. Historically, high-bleed controllers have been used.

A 2003 EPA study reported that emissions from pneumatic controllers are collectively one of the largest sources of methane emissions in the natural gas industry. Estimated annual nationwide methane emissions are approximately 31 billion cubic feet (Bcf) from the production sector, 16 Bcf from the processing sector, and 14 Bcf from the transmission sector. As stated, by definition, high-bleed pneumatic controllers emit more than six scfh of natural gas to the atmosphere. The highest bleed rate listed in one source, a table published by the EPA, is 42 cubic feet per hour (cfh). The average bleed rate for high-bleed pneumatic controllers in the NAA is 21 cfh. Natural gas is primarily composed of methane, but also contains other compounds including VOCs and hazardous air pollutants (HAPs).

VOC emissions from pneumatic controllers within the NAA were 24.8 tons per day (tpd) for the 2006 baseline and have been projected to be 31.1 tpd for the 2010 baseline. These emissions represent 14.0 and 15.1 percent of the total VOC emissions from oil and gas sources in the NAA in 2006 and 2010, respectively. Therefore, emission reductions related to this source category have the potential to be significant.

These rules require that most high-bleed controllers must be replaced with the equivalent of low-bleed or better pneumatic controllers by May 1, 2009. There is an exception that allows high-bleed controllers that the Division agrees are necessary for safety purposes. Operators must inspect and maintain in-use high-bleed controllers on a monthly basis. Operators must also keep logs of the number of in-use high-bleed controllers, as well as the reasoning that high-bleed controller remains in place, and the inspection and maintenance of the in-use high-bleed controllers. These revisions further require operators to physically tag the in-use high-bleed controllers to enable the Division to track compliance.

The oil and gas industry has already begun replacing high-bleed controllers with low-bleed controllers, understanding the financial gain of minimizing the bleed rate of pneumatic controllers.

<u>RICE Controls</u>

Reciprocating internal combustion engine (RICE) requirements of Regulation Number 7, Section XVI. applies in what was the early action compact area (now the Ozone NAA). These revisions extend the RICE requirements' applicability to a state-wide basis.

<u>Expand and Clarify RACT Requirements</u>

Regulation Number 7 is revised to expand its application to all subject sources in any Ozone NAA and Attainment/Maintenance Areas. This previously applied to the one-hour attainment/maintenance area nonattainment area. Accordingly, this regulation will apply to some sources that were previously outside of its geographic scope. It is intended that existing sources become subject to previously adopted Control Technique Guidelines (CTGS) or general RACT requirements, and are given time to comply to implement the general RACT requirements. Specifically, existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements. All new or modified sources become subject to these general RACT requirements upon commencing operation after the new ozone non-attainment designation date. This revision is considered a measured approach to ensuring the consistent use of best practices across the NAA as well as reductions in ozone precursors considered necessary to attaining the 8-hour ozone standard.

This revision expands Regulation Number 7's applicability to any Ozone NAA or attainment/maintenance area. This is done intentionally to apply Regulation Number 7 requirements to current as well as any future Ozone NAA or attainment maintenance areas in Colorado.

Additionally, this revision clarifies how the Regulation Number 3 RACT requirements interact with Regulation Number 7. This revision specifies that pursuant to Regulation Number 7, Section II.C. all existing sources that emit 100 tons per year of VOC emissions and that are located in the 8-hour Ozone NAA become subject to RACT.

Further, Regulation Number 7 is currently unclear on whether or not existing sources that are modified become subject to new source requirements. This revision clarifies that existing sources that are modified are subject to the Regulation Number 3, Part B, Section II.D. requirements and are considered to be a new source for the purposes of Regulation Number 7.

This revision also clarifies that the both case-by-case and general RACT requirements of Regulation Number 7, Section II.C. only apply to existing, new and modified sources. For sources at which all air pollution generating activities at that source are already subject to RACT or BACT, the RACT analysis would show that all activities are already subject to RACT or BACT. For any other air pollution generating activities not covered by RACT or BACT, the source would only have to complete a RACT analysis specific to those activities.

Typographical, Grammatical, Formatting and Other Changes

The commission changed the title of Regulation Number 7 to include NOx. An outline of the sections is provided to better understand the contents of Regulation Number 7. Outdated sections are removed (i.e. Section II.F.1. specific to Gates Rubber Company, which is now out of business). Section XII., specific to condensate tanks in the Ozone NAA is reorganized for clarity. One appendix (new Appendix A) is added to provide maps of Ozone NAAs and chronologies of attainment designations, of which certain requirements key off. Finally, sections and appendices are renumbered and formatted as necessary.

Section 110.5 and 110.8 Analysis

Some of these revisions are not intended to be incorporated into Colorado's SIP. To the extent these revisions could be construed to exceed the requirements of federal law, the Commission provides the following additional statement, consistent with C.R.S. § 25-7-110.5(5)(a):

(I) These rules are intended to reduce uncontrolled emissions of ozone precursor pollutants. The rules thereby serve to attain and maintain compliance with the National Ambient Air Quality Standard (NAAQS) for Ozone. However, there are no comparable federal requirements that apply to the sources in question.

(II) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. There is considerable flexibility in meeting the NAAQS. However, there are very limited sources of uncontrolled anthropogenic ozone precursor emissions to target in order to reduce ozone. Consequently, the sources in question, as a significant source of uncontrolled VOCs and NOx, must be targeted in order to attain the standard.

(III) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. The ozone NAAQS was not determined taking into account concerns that are unique to Colorado.

(IV) These rules may prevent or reduce the need for costly retrofit to meet more stringent requirements at a later date. The DMA/NFR non-attainment area has violated the 0.08 ppm ozone NAAQS. Colorado will soon be required to comply with the new ozone NAAQS of 0.075 ppm. Colorado Governor Ritter has directed that Colorado air quality planning agencies implement measures to reduce ozone to a level below the NAAQS. If these rules are not adopted now, it may be necessary to require costlier retrofitting in order to meet the Governor's directive as well as the new NAAQS.

(V) Since there are no applicable federal requirements, there is no timing issue with regard to implementing federal requirements. However, these controls are intended to help the DMA/NFR attain the NAAQS. If the standard is not attained by the 2010 ozone season, the area may face a "moderate" non-attainment designation.

(VI) The adopted rules will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rules establish reasonable equity for sources subject to the rules by providing the same standards for similarly situated sources.

(VIII) If the state rules were not adopted, other sectors may face a disproportionate share of the burden of reducing precursor pollutants.

(IX) There are no corresponding federal requirements.

(X) Demonstrated technology is available to comply. Sources are already using the control devices intended to be used to comply with these rules. However, sources face an additional burden of implementing auto-igniters and surveillance. The Commission anticipates a reasonable degree of delay in securing and installing the technology in question and has accommodated the sources by providing for a reasonable delay for the application of these requirements.

(XI) The adopted rules will reduce VOC and NOx emissions, thereby contributing to the prevention of the formation of ozone through the most cost-effective means available.

(XII) Alternative rules requiring additional controls for other sources would also provide gains toward attaining the ozone NAAQS. However, oil and gas industry members are the largest anthropogenic stationary source of precursor pollutants in the State. A disproportionate benefit to this industry would accrue if their uncontrolled emissions remain at current levels compared to other stationary sources.

(XIII) A no-action alternative may address the ozone NAAQS. Modeling and other analysis suggests that the NAA would attain the standard by 2010 without these rules. However, this analysis suggests that ambient levels of ozone would be very close to the NAAQS. These rules provide more assurance of attaining the ozone NAAQS while also providing for reductions that are necessary to make progress toward the new ozone NAAQS. No action would only delay the necessary reductions.

Further, pursuant to C.R.S. § 25-7-110.8(1), the Commission 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 ground-level ozone.

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

(IV) The rules are the most cost effective, provide the regulated community flexibility, and achieve any necessary reduction in air pollution.

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

L. January 7, 2011 (Outline and Sections I. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

Basis and Purpose

The Commission intends that the current Regulation Number 7, Section XVII.E.3.a. identifying technology-based control requirements for existing rich burn reciprocating internal combustion engines (RICE), or rich burn RICE that were constructed or modified prior to February 1, 2009, become a NOx emission control measure that is included as part of the Regional Haze SIP and become federally enforceable upon EPA approval.

The technology-based control requirements of Section XVII.E.3.a. reduce NOx. This proposal only changes the enforceability of these currently state-only requirements such that they become federally enforceable. This proposal does not change emission control, monitoring, recordkeeping or reporting requirements.

The Commission also intends that the following provisions, added in Sections XVII.E.3.a.(i)(a) through (c), will continue to be effective under the Regional Haze SIP. Specifically, these provisions require good air pollution control practices and allow for exemptions from the requirements for existing rich burn RICE. The exemptions apply to any existing rich burn RICE either with uncontrolled actual emissions below permitting thresholds or that is subject to a New Source Performance Standard (NSPS), National Emission Standard for Hazardous Air Pollutants (NESHAP), or Best Available Control Technology (BACT) limit.

Existing lean burn RICE requirements are not incorporated into the Regional Haze SIP, as the associated controls do not reduce NOx or SO2.

Colorado has determined that it is reasonable and appropriate to make these RICE requirements federally enforceable in this first planning period, as part of the state’s strategy for addressing reasonable progress towards achieving natural visibility conditions in federal Class I areas.

M. December 20, 2012 (Sections II., XII., and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), Colorado Revised Statutes (C.R.S.) for new and revised regulations.

Basis

Regulation Number 7 is designed to implement substantive regulatory programs authorized under the Colorado Air Pollution Prevention and Control Act (Act) including provisions of the State Implementation Plan (SIP) addressed in C.R.S. Section 25-7-105(1)(a), emission control regulations addressed in C.R.S. Section 25-7-105(1)(b) and authorization of the development of a program for the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) in C.R.S. Section 25-7-301, as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were made to address the U.S. Environmental Protection Agency’s (“EPA”) partial disapproval of Colorado’s ozone SIP.

On August 5, 2011, EPA published the “Approval and Promulgation of State Implementation Plans; State of Colorado; Attainment Demonstration for the 1997 8-Hour Ozone Standard, and Approval of Related Revisions” (76 Fed. Reg. 47443, August 5, 2011). EPA partially approved and partially disapproved revisions to Colorado’s SIP adopted by the Air Quality Control Commission (Commission) in December 2008 and submitted to the EPA in June 2009.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act, C.R.S. Section 25-7-101, et seq., specifically, C.R.S. Section 25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and Section 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

The Commission revised Regulation Number 7 to address the EPA's partial disapproval of Colorado's Ozone State Implementation Plan ("SIP'). On August 5, 2011, the EPA issued a final action on Colorado's June 2009, Ozone SIP submittal, both approving Colorado's attainment demonstration for the 1997 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) and disapproving specific revisions to Regulation Number 7. 76 Fed. Reg. 47443, August 5, 2011. Specifically, the EPA disapproved both the repeal of Regulation Number 7, Section II.D. and all revisions to Section XII. as adopted by the Commission in December 2008. As a basis for its action, the EPA stated that Colorado demonstrated attainment with the 1997 8-Hour Ozone NAAQS, however Colorado did not adequately provide an anti-backsliding demonstration for the revisions to Regulation Number 7 that were adopted by the AQCC in December 2008, and submitted to the EPA in June 2009.

The Commission intends that these 2012 revisions include both SIP and state-only revisions that address EPA's partial disapproval of SIP provisions in Sections II.D and XII., and make related state-only revisions to Section XVII. for consistency.

The Commission does not intend that these 2012 revisions add or strengthen emissions control measures of Section II.D., XII. or XVII. at this time. All SIP revisions are intended to specifically address those provisions that EPA included as part of its basis for disapproving revisions to Regulation Number 7.

While the EPA indicated general approval of the concept of the June 2009 SIP submittal, the EPA took exception to some of the details in the SIP revisions, characterized as "deficiencies," that formed the basis of EPA's disapproval during the SIP review process. EPA's objections to the 2009 SIP revisions and the Commission's responses are summarized as follows:

1. Section II.D. – Alternative Control Plans and Test Methods

   EPA Objection: The EPA objected to the deletion of SIP approved language, allowing for alternative control plans and testing methods.

   Commission Response: The Commission reinstated the SIP approved language.

2. Section XII.C.2. – Emission Factor Calculation Methodology for Condensate Tanks

   EPA Objection: The EPA objected to the deletion of the term "gas-condensate-glycol separators" from the emission factor requirements for atmospheric condensate tanks.

   Commission Response: The Commission made no revision to the rule text, and instead explained to EPA that this term was used in error as such a separator does not exist. The term used here is a misnomer, which the Commission believes refers to a flash tank located on a glycol dehydration unit, covered by Section XII.H. It is inappropriate to apply emission factor calculation methodology for atmospheric condensate tanks to glycol dehydrators because their emissions vary greatly.

3. Section XII.D.2.a. – System-wide Control Requirements for Condensate Tanks

   EPA Objection: The EPA objected to the sunset of the system-wide control requirement in Section XII.D.2.a.(x), which ended the control requirement as of April 30, 2013.

   Commission Response: The Commission revised the system-wide control requirements so that the system-wide control requirements do not sunset. Neither the Commission nor the parties to the December 2008 rulemaking intended for the system-wide control to end. The sunset was unintentionally caused when making other revisions to the rule text.

4. Section XII.E.3. – Monitoring Combustion Devices as Control for Condensate Tanks

   EPA Objection: The EPA objected to providing a state-only monitoring option (electronic surveillance) as a substitution for the SIP required monitoring of combustion devices being used to control emissions from condensate tanks in accordance with Section XII.

   Commission Response: The Commission removed the option of conducting state-only electronic monitoring in lieu of the SIP approved monitoring requirement. This allowance to substitute a SIP required monitoring provision for a state-only monitoring provision was unintentional. None of the sources employing electronic surveillance may use it in place of the SIP approved requirement. If conducted, the electronic surveillance monitoring option must occur in addition to the SIP approved monitoring requirement.

5. Section XII.F.3. – Recordkeeping for Condensate Tanks

   EPA Objection: The EPA objected to the lack of SIP required recordkeeping for the control requirement in Section XII.D.1., which requires all condensate tanks at exploration and production sites to be controlled during the first 90 days of well production.

   Commission Response: The Commission revised Section XII.D.1. to specify it is state-only. The Commission and parties to the December 2008 rulemaking intended for this first 90-day control requirement to be state-only, which corresponds to the state-only designation on the recordkeeping requirements under Section XII.F.3. Therefore, the Commission made no revision to Section XII.F.3., and instead revised Section XII.D.1. to alleviate this discrepancy.

6. Section XII.F.5. – Recordkeeping and Reporting Exemption for Compressor Stations and Drip Stations

   EPA Objection: The EPA objected to the removal of a SIP approved provision that exempted natural gas compressors or drip stations from recordkeeping and reporting requirements, where total emissions from such facilities are less than 30 tons per year.

   Commission Response: The Commission reinstated the SIP approved 30 tons per year provision.

7. Section XII.G.2. – Control Equipment Requirement for Natural Gas Processing Plants

   EPA Objection: The EPA objected to two aspects of the revisions to this section. The first objection was replacement of the term “APEN de minimus levels” with “greater than or equal to two tons per year.” The second objection was inclusion of a rolling 12-month averaging period for the 95% control requirement.

Commission Response: The Commission made no revision to the replacement of the term "APEN de minimus levels." The Commission explained to the EPA that the associated modeling relied on evaluating condensate tanks with emissions greater than or equal to two tons of volatile organic compounds per year. Therefore, the change in reference does not constitute a lessening of the stringency of the rule. In addition, the Commission removed the rolling 12-month averaging period.

8. Section XII.G.5. Recordkeeping and Reporting for Alternative Compliance Option

   EPA Objection: The EPA objected to the reliance on Title V or construction permits as the location for recordkeeping and reporting requirements for condensate tanks at natural gas compressor or drip stations.

   Commission Response: The Commission revised this section to specify recordkeeping and reporting requirements for condensate tanks at natural gas compressor and drip stations.

9. Section XII.H. Control Requirements for Glycol Dehydrators

   EPA Objection: The EPA stated this entire section lacked clarity and contained redundant language.

   Commission Response: The Commission revised the section in its entirety, while maintaining the intent and applicability of the requirements. Along with this revision, the Commission specified that this control requirement is applicable only to glycol dehydrators with emissions equal to or greater than one ton per year, but that all glycol dehydrators at a stationary source must be included for comparison to the 15 ton per year threshold. The term stationary source is defined in the Common Provisions. Further, the Commission revised the provision to include emission calculation methodology requirements in Section XII. H.

Items 1-9 are all SIP revisions.

In addition, the Commission is also revising the state-only Section XVII.D. for consistency with the 2012 SIP revisions. The Commission does not intend that this state-only revision change the applicability of the control requirements for glycol natural gas dehydrators. Finally, the Commission made typographical, grammatical, and formatting revisions, as necessary.

N. February 23, 2014 (Sections II., XVII., and XVIII.)

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

<u>Basis</u>

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 CFR Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result and further addresses the volatile organic compound ("VOC"), an ozone precursor, and other hydrocarbon emissions, such as methane, from the oil and gas sector.

The Commission supports the EPA's development of NSPS OOOO and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. First, the Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"); it is likely that EPA will lower the ozone NAAQS in the near future, potentially expanding Colorado's nonattainment area; and Division air monitors and other sampling indicate elevated levels of oil and gas related air emissions in oil and gas development areas. Second, Colorado has seen substantial growth of oil and gas development in recent years, which is a significant source of VOC emissions, and expects that growth to continue in the foreseeable future. In particular, oil and gas storage tanks contribute significantly to the VOC emissions from oil and gas development. Further, oil and gas operations also emit methane, a negligibly reactive ozone precursor and potent greenhouse gas. Third, oil and gas operators have had difficulty meeting the current 95% control requirements in Regulation Number 7 established for condensate tanks in 2004 and 2006 due to "flash" emissions. Fourth, improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs and methane in a cost-effective manner. These technologies and practices include, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras).

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both SIP and state-only requirements. During the rulemaking process, various parties provided extensive evidence concerning whether the proposed revisions, in particular the STEM and LDAR requirements, should apply either statewide or only in the ozone nonattainment area. Based upon careful consideration of all the evidence provided during the rulemaking, the Commission determined it was appropriate to apply the proposed requirements statewide. Further, in addition to the extensive evidence concerning the benefits of statewide hydrocarbon emission reductions, the Commission believes that the tiered and phased nature of many of the requirements properly focuses on emissions. Under this tiered approach, lower emitting sources such as marginal, stripper, and coal bed methane wells will appropriately be subject to less rigorous and costly requirements. In addition, evidence in the rulemaking record and testimony of industry members supports the conclusion that the rules can be effectively implemented. Accordingly, the Commission concludes that the proposed rules are technologically feasible and cost-effective. Moreover, because these revisions apply on a state-wide, state-only basis, and are not a part of Colorado's SIP, the Commission, the Division, and stakeholders have the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and natural gas compressor stations. The Commission expands existing oil and gas control requirements and establishes additional monitoring, recordkeeping, and reporting requirements. For example, the revisions increase control requirements and improve capture efficiency requirements for oil and gas storage tanks. The Commission also seeks to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells and wells undergoing maintenance and during liquids unloading events. The Commission also expands control requirements for pneumatic devices and glycol natural gas dehydrators. The Commission believes that this combination of revisions is appropriate to complement the full adoption of NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, remove the off-ramp for condensate tanks if subject to a NSPS, MACT, or BACT, and remove the leak detection and repair requirements off-ramp for glycol natural gas dehydrators and internal combustion engines if subject to a NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;
- Limit venting and establish a storage tank emissions monitoring system ("STEM"), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol natural gas dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for natural gas compressor stations and well production facilities in Section XVII.F.;
- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance and liquids unloading in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVIII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Joint Applicability of NSPS OOOO and Regulation Number 7, Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates some overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with six (6) tons per year ("tpy") of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. It is the Commission's intent that compliance with Regulation Number 7, Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions from storage vessels under NSPS OOOO. In those limited cases where storage tanks are subject to both NSPS OOOO and Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring. However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy, the equivalent of the NSPS OOOO six (6) tpy VOC on a controlled actual basis. While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary and intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT control requirement to avoid having to comply with Section XVII.

It is also possible for glycol natural gas dehydrators and internal combustion engines to be subject to both federal and Regulation Number 7, Section XVII. leak detection and repair requirements. NESHAP HH and HHH require glycol natural gas dehydrators at major sources of hazardous air pollutants ("HAP") that utilize a closed-vent system to conduct annual visual inspections for leaks and defects that could result in air emissions. NESHAP HH and HHH also require detected leaks and defects be repaired within fifteen days, as long as it is technically feasible to do so without a shutdown. NESHAP HH also requires triethylene glycol ("TEG") natural gas dehydrators located at area sources of HAPs that utilize a closed-vent system to conduct annual visual inspections. However, the revisions to Regulation Number 7 require more frequent inspections of all types of glycol natural gas dehydrators at all facilities, resulting in more emissions reductions than NESHAP HH and HHH. Therefore, the Commission believes joint applicability concerning leak detection and repair requirements is necessary.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC and other hydrocarbon emissions, such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of greater than or equal to one (1) minute during a fifteen (15) minute time period, pursuant to EPA Method 22. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. The regulated community may, alternatively, immediately shut-in the equipment to investigate the cause for smoke and perform repairs. While the presence of visible emissions constitutes a violation of the rules, the Commission recognizes that there may be instances where visible emissions occur notwithstanding the owner or operator’s best efforts, such as when an upset or malfunction occurs. Accordingly, the Division should consider the owner or operator’s efforts and whether the visible emissions resulted from factors outside the owner or operator’s control in determining how to best enforce this requirement.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth.

“Approved instrument monitoring method” (“AIMM”) means the methods and technologies utilized for monitoring storage tanks and components at well production facilities and natural gas compressor stations. The instrument being used for AIMM inspections must be capable of measuring hydrocarbon compounds at the applicable leak definition concentration specified in the revisions, and calibrated as appropriate. See EPA Method 21 at 6.0. In addition, while the definition lists EPA Method 21 and IR cameras, the Commission does not intend to limit industry to only EPA Method 21 and IR cameras as the Division may approve the use of additional monitoring devices and methods.

“Component” excludes compressor seals and open-ended valves and lines, which are defined separately, because they are designed to leak and are better addressed with equipment specific work practices, also included separately. Based on concerns that the requirements for small reciprocating compressors at well production facilities may not be cost-effective, the adopted work practices for reciprocating compressors are limited to reciprocating compressors located at natural gas compressor stations. Nevertheless, there is an issue as to whether compressors at well production facilities are a significant source of emissions. The Commission, therefore, directs the Division to investigate whether reciprocating compressors at well production facilities are a significant source of emissions, and if so, whether there may be appropriate, cost-effective work practices to reduce fugitive emissions from reciprocating compressors at well production facilities. The Commission further directs the Division to brief the Commission on this investigation in March, 2015.

“Date of first production” is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission’s (“COGCC”) as the “date of first production,” as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both COGCC and Commission requirements.

“Natural gas compressor stations” are subject to leak detection and repair requirements. This definition is meant to exclude compressors at well production facilities and gas processing plants. This definition is also meant to exclude natural gas compressor stations that are downstream of the natural gas processing plant at this time.

“Normal operation” is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of “malfunction” as set forth in the Common Provision regulations.

"Storage tank," means a single storage tank or a storage tank battery if the storage tanks are manifolded together. In recent years, it has become more common for multiple storage tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of "storage tank," the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery. The Commission's definition, and Colorado's approach to emissions reporting and permitting for storage tanks, differs from EPA's definition of "storage vessel" and the description of an affected storage vessel facility in NSPS OOOO because EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. The Commission intends to maintain this distinction and, therefore, deletes the previously used definition of "atmospheric condensate storage tank" and creates a new definition of "storage tank" which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

"Well production facilities" are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The "owned, operated, or leased" qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from "well production facility" and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells.

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas operations, including those below control thresholds or even below Regulation Number 3 APEN and permitting thresholds, adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;

- Inspecting and repairing seals on thief hatches, access points, or other openings of storage tanks;

- Initiating timely action to address leaks or unpermitted emissions; and

- Maintaining equipment and the facility in good operating condition.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. The Commission intends these revisions to address venting emissions from storage tank thief hatches, pressure relief valves, or other access points during normal operations. Access points are not limited to points of entry of liquids or gas into the storage tank but include any route from which emissions can escape. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices and that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. The Commission does not intend to increase risk or compromise safety of personnel and equipment. However, inadequate design of a storage tank emissions capture system is not a legitimate reason for venting.

Therefore, the Commission intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to owners or operators, provided that the owners or operators demonstrate that the elements of the malfunction defense have been met. The Commission intends that the burden remain on the owner or operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2. The Commission further recognizes that meeting the no venting requirement may be challenging in some cases, and accordingly has adopted additional provisions requiring owners and operators to develop a STEM plan to help ensure compliance. In some cases, development and implementation of the STEM plan may be an iterative process involving ongoing improvements before continuous compliance with the no venting standard is achieved. With this in the mind, the Division should consider the efforts of owners and operators in developing and implementing their STEM plan as part of the Division's assessment about how best to enforce the no venting requirement.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and natural gas compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered by the owner or operator or the Division inspector pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if a leak is identified and the owner or operator is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the owner or operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners or operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tanks Controls (Section XVII.C.)

EPA established a six (6) tpy VOC threshold on a controlled actual emissions basis for applying storage vessel controls. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for applying reporting, permitting, and control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control equipment may be removed if: (1) the storage tank (including manifolded tanks) emissions fall below the uncontrolled actual six (6) tpy threshold, on a rolling twelve-month basis; and (2) those controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the uncontrolled actual six (6) tpy threshold on a rolling twelve-month basis, air pollution control equipment must be installed within sixty (60) days of discovery of the increase.

The Commission does not intend for the storage tank control, or related, requirements to apply to frac tanks that are located at a well production facility for less than 180 consecutive days.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used the device must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Audio, Visual, Olfactory ("AVO") and Visual Inspections (Section XVII.C.)

The Commission intends that owners and operators of subject storage tanks (including storage tanks during the first ninety (90) days of production and storage tanks containing only stabilized liquids) conduct applicable AVO and visual inspections for venting or leaking. Visual inspections are in addition to AVO monitoring and require further inspections of the storage tank and associated equipment, such as thief hatches and air pollution control equipment. These inspections are not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO and visual inspection, and indicates the frequency at which inspection is required.

Storage Tank Emission Management System ("STEM") Plan, Monitoring, and Recordkeeping (Section XVII.C.)

Owners and operators of storage tanks with uncontrolled actual emissions equal to or greater than six (6) tpy must develop, certify, and implement a STEM plan designed to ensure compliance with the "without venting" requirement of Section XVII.C.2., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies, monitoring, maintenance, and operational practices to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility to develop STEM plans on an individual basis for each storage tank or for multiple storage tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review. Owners and operators of storage tanks controlled during the first ninety (90) days of production or containing only stabilized liquids are not required to develop and implement a STEM plan. However, owners or operators of such storage tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include, but is not limited to, the following elements:

- A monitoring strategy including, at a minimum, the applicable inspection frequencies and methodologies;
- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the owner or operator to demonstrate the quality and achievements of the STEM plan;
- The calibration methodology and schedule for emission detection equipment used in the monitoring;

- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;

- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;

- A procedure to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and

- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

In addition to AVO and visual inspections for storage tanks, STEM plans must include AIMM inspections on a frequency schedule that is tied to the uncontrolled actual VOC emissions from the storage tank. The Commission intends that the AIMM inspection satisfy any simultaneous AVO and visual inspection requirement.

The STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of applicable monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Unsafe, Difficult, or Inaccessible to Monitor (Sections XVII.C. and XVII.F.)

The Commission does not intend to require owners or operators to conduct either AVO or AIMM inspections of unsafe, difficult, or inaccessible components or storage tanks and associated equipment. The Commission acknowledges that, in limited circumstances, unsafe to monitor may include unsafe weather or travel conditions. However, in those limited circumstances, the Commission expects the owner or operator to resume monitoring once the weather or travel conditions cease to be unsafe. Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season.

Glycol Natural Gas Dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. This revision requires that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of six (6) tpy or greater be controlled with air pollution control equipment achieving at least a 95% reduction. This revision also requires that existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled if the dehydrator is located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations.

The Commission does not intend to apply this proximity requirement to the glycol natural gas dehydrator owner or operator’s buildings, where public access to the building is also restricted. Further, because glycol natural gas dehydrators are different and unique sources, a similar proximity requirement for storage tanks is not appropriate at this time as storage tanks are more appropriately addressed based on emission thresholds.

This revision also requires that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. The leak detection and repair program more broadly targets leaks from components at natural gas compressor stations and well production facilities, even if such facilities do not include storage tanks. In contrast, STEM targets venting from storage tanks. The use of an AIMM as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may have lower emissions and may need additional time to comply. Owners or operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor. Owners or operators also have flexibility in timing the AVO and AIMM inspections to coordinate overlapping AVO and AIMM inspections, as well as inspections of facilities in the same area or on the same inspection frequency. The Commission intends that the AIMM inspection satisfy any simultaneous AVO inspection requirement. However, the Commission expects that owners and operators will also utilize this flexibility to ensure that inspections are appropriately spaced on the frequency schedule (e.g. quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Commission distinguished between new and existing well production facilities by utilizing an October 1, 2014, commenced construction date and created an inspection phase-in schedule for existing facilities.

The Commission also distinguished the emissions thresholds for determining inspection frequencies for well production facilities with storage tanks and well production facilities without storage tanks. For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on “facility emissions.” The Commission has determined that “facility emissions” means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.

The Commission has defined a leak requiring repair in a manner that is dependent on the monitoring methodology. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identify the emission rate. Similarly, while IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in selecting a leak detection methodology.

If EPA Method 21 is utilized, the Commission set the threshold at which component leaks must be repaired at 2,000 parts per million (“ppm”) hydrocarbons for existing natural gas compressor stations and 500 ppm for new (constructed after May 1, 2014) natural gas compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is utilized, a leak is any detectable emission not associated with normal equipment operation (e.g. the acceptable level of leaks from a component designed to leak). These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources.

Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO identifies leaks at natural gas processing plants at 500 ppm. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices. Further, the Commission finds that the repair deadlines set forth in Section XVII.F.7. provide flexibility for operational differences, including the potential range of leaks and degrees of repair difficulty that may be encountered.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country.

The Commission expects that owners and operators will remonitor leaks requiring repair with either the approved instrument monitoring method the owner or operator used to identify the leak or any method approved for remonitoring of leaks under EPA Method 21.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in permits existing as of the promulgation date of the revisions. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and owners and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

During the rulemaking, several parties requested more stringent requirements for all oil and gas operations located within 1,320 feet of a building unit or designated outside activity area. Residents living within close proximity to oil and gas operations, particularly those living within 1,320 feet of oil and gas operations, may understandably have heightened concerns regarding potential impacts of emissions from such facilities. It is the Commission's understanding that some oil and gas owners and operators implement practices beyond what is currently required under state law in order to minimize emissions and otherwise be good neighbors, including conducting increased site inspections. The Commission supports such practices.

Also during the rulemaking, various parties provided extensive evidence concerning the frequency of instrument monitoring method inspections, the timing of leak repair, and the costs and benefits associated with more or less frequent monitoring and repair. The Commission recognizes that additional information would benefit the Commission, Division, industry, and other stakeholders and therefore encourages the Division to work with energy companies, to evaluate the comparative effectiveness of various kinds of instrument based monitoring methods and program designs at a range of types, sizes, and frequencies at well production facilities and natural gas compressor stations.

The Commission also encourages the Division to work with industry and other stakeholders to evaluate emissions from and potential control strategies for downstream natural gas compressor stations and intermittent pneumatic controllers.

Lastly, several parties to the rulemaking requested greater transparency and public access to air quality information associated with oil and gas development. In particular, a coalition of local community organizations requested that owner and operators' annual reports as required by these rules be posted on the Division's website. The Commission believes these reports will provide important information when reviewing the efficacy of the inspection and maintenance program, as well as valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make this information available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. In addition, the Commission requests an annual briefing on these regulations. Such briefing will assist the Commission and interested stakeholders to understand the data and implementation issues relating to this new program, as well as other initiatives covered in this rulemaking. The Commission believes that this information would also be valuable to all parties.

Well Maintenance and Liquids Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well maintenance and well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading emissions are estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008, rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. However, the Commission does not intend to expand the pneumatic device requirements to intermittent pneumatic controllers at this time. Further, while the use of low-bleed pneumatic controllers will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources.

However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is only requiring the use of no-bleed pneumatic controllers at facilities that are connected to the electric grid, using electricity to power equipment, and where technically and economically feasible.

<u>Additional Considerations</u>

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Sections XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) The revisions to Regulation Number 7 address VOC and other hydrocarbon emissions from oil and gas facilities, including storage tanks, glycol natural gas dehydrators, pneumatic controllers, well production facilities, and natural gas compressor stations. In addition to NSPS OOOO, NSPS Kb, and NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks, glycol natural gas dehydrators, leaking components, and pneumatic controllers, and address more hydrocarbon emissions. For example, the Regulation Number 7 revisions address more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to TEG dehydrators. Similarly, the Regulation Number 7 revisions address more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. In addition, the Regulation Number 7 revisions address more component leaks than the major source provisions of NESHAP HH, as well as NSPS KKK, which has a 10,000 ppm leak threshold and only applies at natural gas processing plants.

Compared to NSPS OOOO, the revisions to Regulation Number 7 will apply a low- or no-bleed control requirement to more pneumatic controllers because NSPS OOOO only requires zero bleed pneumatic controllers at natural gas processing plants, while the Regulation Number 7 revisions no-bleed provision applies to all facilities. The revisions to Regulation Number 7 will also require a leak detection and repair program for more oil and gas operations because NSPS OOOO only requires leak detection and repair for natural gas processing plants, AVO inspections for storage vessels with controlled actual emissions greater than six (6) tpy, and annual visual inspections for leaks for subject centrifugal compressors. In contrast, the revisions to Regulation Number 7 require a leak detection and repair program for all components at all well production facilities and natural gas compressor stations. Further, the revisions to Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to further address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

(II) NSPS OOOO, and the other federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, which may be used to avoid NSPS OOOO applicability.

(III) Other federal requirements do not specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. Specifically, during the development of NSPS OOOO, Colorado submitted comments regarding, among other things, concerns with the storage vessel definition, storage vessel control requirements, and lack of leak detection and repair requirements. Colorado's concerns were not fully addressed in NSPS OOOO, therefore, the Commission believes the revisions to Regulation Number 7 are necessary to: (a) address hydrocarbon emissions in a more comprehensive manner; (b) address oil and gas operations and equipment at lower thresholds than NSPS OOOO thresholds, yet that collectively have significant VOC and other hydrocarbon emissions in Colorado; (c) address venting of emissions from storage tanks at oil and gas facilities caused primarily by over pressurization; and (d) address leaks of fugitive hydrocarbon emissions, particularly from well production facilities and natural gas compressor stations.

(IV) Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for costlier retrofits at a later date. Colorado may be required to comply with a lower ozone NAAQS in the near future and the Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS, while other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. The revised rules are proactive and intended to reduce ozone levels now by utilizing controls and techniques already being used by some Colorado oil and gas operators, or that are readily available.

(V) Adoption of these revisions at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

(VI) The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while utilizing many of the technologies and practices set forth in these revisions.

(VII) The revisions to Regulation Number 7 establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector. Furthermore, the application of the Regulation Number 7 revisions to oil and gas owners and operators regardless of location in the ozone nonattainment or attainment areas is equitable because the nonattainment area is not the only area in Colorado with ozone issues. For example, the Rangely monitor in western Colorado shows violations of the 2008 ozone standard and existing modeling shows that either the nonattainment area has increased its contribution to background ozone or ozone concentrations in the attainment area flowing into the nonattainment area have increased. Notably, the Division's inventory shows that the oil and gas industry contributes more than 50% of the VOC emissions outside the nonattainment area. This monitoring, modeling, and inventory data, considered with the likelihood of a lower ozone NAAQS and the expected growth of the oil and gas sector state-wide, supports the application of the Regulation Number 7 revisions to oil and gas sources in both the nonattainment and attainment areas.

(VIII) The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions. In reductions must come from other operations or sectors at this time, the cost effectiveness would decrease because these revisions reduce emissions from the most significant contributors to VOC emissions and costs will be higher for less emissions reductions from less significant contributors.

(IX) The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO (e.g. storage vessels emitting 120 tpy uncontrolled actual VOC emissions) or NESHAP HH and HHH (e.g. glycol natural gas dehydrators at major sources of HAPs and TEG glycol natural gas dehydrators at area sources of HAPs) and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to ensure compliance with and document the effectiveness of the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the requirements for auto-igniters and pneumatic controllers. In addition, oil and gas owners and operators are already using many of the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides owners and operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the revisions provide for Division approved extensions to compliance.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The reductions of other hydrocarbon emissions, such as methane, add to the already cost-effective and appropriate emission reduction requirements.

(XII) Alternative rules, such as the alternative proposals provided by several parties during the rulemaking process, requiring differing or additional controls for oil and gas facilities could also provide reductions in hydrocarbon emissions. The Commission could have adopted some or all of the proposed revisions or proposed alternatives. However, the proposed revisions to Regulation Number 7 were developed during a lengthy stakeholder process and provided a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. The alternative proposals provided during the rulemaking process were primarily either more or less stringent versions of the proposed revisions, further illustrating the balanced approach of the proposed revisions. Furthermore, a no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursor pollutants, necessary for reducing ozone in Colorado.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.

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

(VI) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

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

O. November 17, 2016 (Sections I., X., XII., XIII., XVI., XIX.)

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

<u>Basis</u>

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data. Due to the reclassification, additional planning requirements were triggered, including the requirement to submit revisions to the State Implementation Plan ("SIP") that address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA Section 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)).

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive state implementation plan that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 25-7-109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions. Separately, EPA had expressed concerns with approving previous Regulation Number 7 revisions related to oil and gas control requirements and submitted in 2009 and 2013 for inclusion in Colorado's ozone SIP.

In response to these related but separate issues, the Commission revised Regulation Number 7 to strengthen Colorado's ozone SIP; and include reasonably available control technology ("RACT") requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of volatile organic compounds ("VOC") or nitrogen oxides ("NOx"). More specifically, the Commission revised the applicability of Regulation Number 7 in Section I.A.1.; included the existing combustion device auto-igniter requirements in Section XII.C.1.e. and XII.E.2. in Colorado's ozone SIP; included existing audio, visual, olfactory ("AVO") storage tank inspection requirements for condensate storage tanks in Colorado's ozone SIP in Section XII.E.4.e.; added requirements for lithographic and letterpress printing in Section XIII.B.; added requirements for industrial cleaning solvents in Section X.E.; and added requirements for major sources in Sections XVI. and XIX.

Apart from the Moderate nonattainment area ozone SIP, the Commission revised Regulation Number 7 to address EPA's monitoring, recordkeeping, reporting, and other concerns with previously submitted Regulation Number 7 revisions. The Commission updated federal rule references for natural gas processing plants in Section XII.G.1.; renumbered the current Sections XII.G.5. and XII.G.6. under Section XII.I.; added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in Sections XII.H.5. and XII.H.6.; and addressed other EPA concerns in Sections XII.C.1.c., XII.C.1.d., XII.C.2.a.(ii)(B), XII.E.3., and XII.H.4.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

<u>Ozone reclassification SIP revisions</u>

8-hour ozone control area

All provisions of Regulation Number 7 currently apply to the Denver 1-hour ozone nonattainment and attainment/maintenance area. The 1-hour ozone area does not include all of Adams and Arapahoe counties or the portions of Larimer and Weld counties included in the 8-hour ozone control hour. Therefore, to ensure that all sources in the 8-hour ozone nonattainment area are subject to applicable RACT requirements in Regulation Number 7 on a federally enforceable basis, the Commission revised Regulation Number 7, Section I.A.1.a. to state that all provisions apply to both the 1-hour and 8-hour ozone areas. The Commission intends that provisions clearly marked “state-only” continue to be enforceable only on a state-only basis, and are not included in the SIP.

Auto-igniter and storage tank AVO

Regulation Number 7, Section XII.C.1.e. includes auto-igniter requirements for combustion devices used to control emissions of VOCs. Pursuant to Section XII.E., the auto-igniter must be inspected weekly to ensure it is properly functioning. Prior to the revision, these requirements were “state-only”. The Commission revised these provisions to include the auto-igniter installation, operation, and monitoring requirements in the SIP.

Regulation Number 7, Section XII.E. includes requirements for owners or operators of condensate storage tanks subject to Section XII.D. to inspect combustion devices, vapor recovery units, control devices, and thief hatches. These are SIP requirements. Regulation Number 7, Section XVII.C.1.d. also requires of owners or operators of storage tanks subject to Section XVII. to conduct AVO and additional visual inspection at the same frequency as liquids load-out. The requirements of Section XVI.C.1.d. are enforceable on a “state-only” basis. The Commission revised Section XII. to include in the SIP, the requirement that owners and operators conduct AVO inspections of condensate storage tanks with uncontrolled actual VOC emissions of 6 tons per year (“tpy”) or greater, making them federally enforceable.

Lithographic and letterpress printing RACT

Pursuant to CAA Section 182(b), Colorado’s ozone SIP must provide for implementation of RACT at sources of VOC for which EPA has issued a Control Technique Guideline (“CTG”). EPA’s Offset Lithographic Printing and Letterpress Printing CTG (“Printing CTG”) addresses VOC emissions from the use of fountain solutions, cleaning materials, and inks at lithographic and letterpress printing operations. The Printing CTG recommends controlling VOC emissions from heatset printing with dryer emissions of at least 25 tpy of VOC from heatset inks with add-on control technology. The Printing CTG recommends controlling VOC emissions from cleaning materials and fountain solutions at printing operations with facility emissions equal to or greater than 15 lb/day by limiting the VOC content of cleaning materials and fountain solutions. The Printing CTG also recommends work practices for printing operations with facility emissions equal to or greater than 15 lb/day.

Colorado has sources in the ozone nonattainment area in this CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included these requirements in Section XIII.B. as RACT for these sources. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy. This is roughly equivalent to the 15lbs/day threshold recommended in the Printing CTG. Based on the Printing CTG, the Commission added language to Section XIII.B.1.b. clarifying that fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses are considered part of the printing process and are not subject to the surface coating or industrial cleaning solvent requirements in Regulation Number 7. With respect to the compliance threshold for Section XIII.B., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. Only emissions from the printing operation and cleaning thereof should be considered in determining if emissions exceed 3 tpy.

The Commission included additional work practices, a VOC content limit for inks and monitoring, recordkeeping and performance testing requirements that are not specified in the Printing CTG but are intended to correspond to current permit requirements and ensure the enforceability of the requirements. With respect to the work practice requirements contained in Section XIII.B.1.c., the Commission applied these requirements to all lithographic and letterpress printing operations, regardless of potential or actual VOC emissions, because they are minimally burdensome, good housekeeping requirements that reduce emissions and correspond to current permit requirements. With respect to the VOC content limit for inks, the Commission included a 40% limit for heatset web offset and heatset web letterpress printing operations that require higher VOC content ink, and a 30% limit for all other lithographic and letterpress printing operations that are commonly already using low VOC inks. Compliance with the VOC content requirement for inks is demonstrated using a weighted average which takes into account the amount of the different inks used and their respective VOC contents.

For consistency with the Printing CTG, cleaning solutions are subject to VOC content or vapor pressure requirements, except that sources using less than 110 gallons of non-compliant cleaning materials per calendar year are exempt from the VOC content or vapor pressure requirements. Larger heatset printing operations, whose maximum allowable emissions before controls from petroleum inks are 25 tpy VOC or more, are subject to a control requirement (not capture and control). Printing operations' emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Industrial cleaning solvents RACT

EPA's CTG for Industrial Cleaning Solvent ("Cleaning Solvent CTG") addresses solvent use in cleaning operations such as spray gun cleaning, spray booth cleaning, large manufactured components cleaning, parts cleaning, equipment cleaning, line cleaning, floor cleaning, tank cleaning, and small manufactured components cleaning. The Cleaning Solvent CTG applies to facilities with VOC emissions from the use of industrial cleaning solvents equal to or greater than 15 lb/day of VOC. The Cleaning Solvent CTG recommends a cleaning solvent VOC content limit and work practices.

Colorado has sources in the ozone nonattainment area in this Cleaning Solvent CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included requirements in Section X.E. as RACT. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy on a calendar basis. This is roughly equivalent to the 15lbs/day threshold recommended in the CTG. The Commission intended for the term "industrial cleaning solvent operation" to be broad and apply to a wide range of work areas where manufacturing or repair activities are performed, but not to residential or janitorial cleaning.

The Commission included language to clarify that VOC emissions that are exempt from the industrial cleaning solvent rule do not count toward this 3 tpy threshold. Therefore, when determining whether a facility meets the applicability threshold of 3 tpy, a source should include facility-wide emissions from all industrial cleaning solvent operations and subtract those emissions that are exempt under Section X.E.4. In adopting the VOC content limit in Section X.E.1.a. and the vapor pressure limit in Section X.E.1.b., the Commission intended for these to be straight, as-applied limits for all industrial cleaning solvents used and not a weighted average. Additionally, in adopting the 90% control efficiency compliance option in Section X.E.1.c., the Commission did not intend for this control efficiency to include capture efficiency. The Commission acknowledged that capture efficiency may be lower than the control efficiency because industrial cleaning solvents are often used over large industrial complexes and result in relatively small VOC emissions.

With respect to the compliance threshold for Section X., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. The Commission also included monitoring, recordkeeping and reporting requirements that are not specified in the Cleaning Solvent CTG but are intended to align with current permit recordkeeping requirements and ensure the enforceability of the requirements.

The Commission included language in Section X.E.4.a.(ii) providing that industrial cleaning solvent operations subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT are exempt from the requirements of Section X. This provision was included so as not to subject sources to overlapping, duplicative, or contradictory RACT requirements. Therefore, if an industrial cleaning solvent operation is subject to a work practice or emission control requirement contained in another, federally approved section of Regulation Number 7, including but not limited to Sections IX. (surface coating operations), X.B. through X.D. (solvent cold-cleaners, non-conveyorized degreasers, and conveyorized degreasers), and XIII. (graphic arts and printing), then that operation would not also be subject to the requirements of Section X.E.4. However, this provision is not intended to exempt an industrial cleaning solvent operation from Section X. when the operation is subject to the restriction on disposal of VOCs by evaporation or spillage contained in to Section V.A. (and RACT is determined to be nothing). Therefore, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be nothing, the operator must comply with Section X. Conversely, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be a work practice or emission control requirement, then the operation is exempt from Section X. Lastly, the Commission adopted additional exemptions recommended in the Cleaning Solvent CTG in Section X.E.4.b. as well as an alternative compliance option for area source aerospace facilities in Section X.E.4.c. due to the unique solvent cleaning needs of those source categories.

Control requirements do not account for capture and control. General industrial solvent use emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Major VOC and NOx source RACT

Colorado has major sources of VOC or NOx (sources that emit or have the potential to emit greater than 100 tpy) in the DMNFR. While many of these sources are currently subject to regulatory RACT requirements in Colorado’s SIP, some of the sources or emissions points are subject to RACT requirements in federally enforceable permits or New Source Performance Standard (“NSPS”) or National Emission Standard for Hazardous Air Pollutants (“NESHAP”). However, as a Moderate nonattainment area, Colorado is submitting a SIP revision to include provisions requiring the implementation of RACT for major sources of NOx or VOC in the DMNFR. Therefore, the Commission included a work practice for combustion equipment at major sources of NOx emissions in Section XVI., a requirement for specific major sources to provide RACT analyses to the Division in Section XIX.B., and incorporated by reference applicable requirements of a NSPS or NESHAP in Sections XIX.C-G.

Specifically, the Commission adopted a combustion process adjustment requirement for individual pieces of combustion equipment at major sources of NOx in Section XVI.D., expanding on work practices currently required in federal NESHAP. The combustion process adjustment was modeled after NESHAP DDDDD, which applies to boilers and process heaters at major HAP sources, and NESHAP ZZZZ, which establishes various requirements for stationary reciprocating internal combustion engines. Section XVI.D. is intended to apply to some equipment that is not subject to work practices under the NESHAPs (e.g., natural gas fired boilers at area sources of HAPs) that have uncontrolled actual NOx emissions (annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice without consideration of any emission control equipment or procedures) equal to or greater than 5 tpy. The Commission intended major NOx sources to use the most recent APEN submitted to the Division as of January 1, 2017, to determine whether the combustion equipment is subject to the requirement to conduct an initial combustion process adjustment by April 1, 2017, or alternatively document reliance on an allowed, alternative adjustment. Subsequent determinations will be based on the most recent APEN submitted to the Division as of the year the combustion equipment may be subject to the combustion process adjustment requirements (e.g., most recent APEN submitted to the Division as of January 1, 2018, to determine whether a combustion process adjustment is required in 2018). In addition to the specific adjustment requirements, the Commission intended owners and operators to operate and maintain subject equipment consistent with manufacturer specifications or best combustion engineering practices.

The Commission also established RACT requirements for emission points at major sources of VOC or NOx in the DMNFR area in Section XIX. In Section XIX.A., the Commission listed all major sources of VOC or NOx at the time of adoption of the Moderate nonattainment area RACT SIP. The Commission determined that not all emission points above permitting thresholds at major sources were necessarily subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP. Therefore, in Sections XIX.C. through XIX.G., the Commission incorporated federal NSPS or NESHAP requirements, including monitoring, recordkeeping, and reporting requirements, for some sources to further satisfy Colorado's RACT obligation for Colorado's major VOC and NOx sources. The Commission acknowledges concerns over potential EPA revisions to NSPS and NESHAP incorporated by reference in Sections XIX.C. through XIX.G., and intended that sources comply with applicable requirements in the most up-to-date version of the federal rule, or alternative requirements approved by EPA in accordance with the NSPS or NESHAP. The Commission also directs the Division to initiate efforts to update the incorporation by reference in the SIP, as necessary and with all due diligence. Sources identified in Section XIX.A. but not specifically included in Sections XIX.B. through XIX.G., were determined to be subject to other, existing regulatory RACT requirements in Colorado's SIP (see the Moderate ozone SIP revision, RACT Chapter 6 and the Technical Support Document for Reasonably Available Control Technology for Major Sources for additional detail). Concerning major sources or source emission points not subject to other, existing regulatory RACT requirements in Colorado's SIP or specified in Sections XIX.C. through XIX.G., the Commission required owners or operators to submit RACT analyses for the facility or specific emission points to the Division by December 31, 2017. The RACT analyses should identify potential options to reduce NOx and/or VOC emissions from the facility or emission point(s), propose RACT for that facility or point, propose associated monitoring, propose a schedule for implementation, and include economic and technical information showing why the RACT proposal is RACT for the particular facility or point. These RACT analyses are not to be limited by a January 1, 2017, implementation date.

CoorsTek submitted a permit application to limit permitted emissions of VOC below 100 tpy. Metro Wastewater Reclamation District submitted an application for minor modification to its Title V permit to correct inconsistencies and remove obsolete limits, which lowered the combined Metro Wastewater/Suez Denver Metro permitted NOx emission limit below 100 tpy. Consequently, the Commission determined that the facilities no longer met the definition of a major source, and therefore were not included in Section XIX. Should either source fail to obtain such federally enforceable permits by July 1, 2018, the Commission directs the Division, with all due diligence, to initiate efforts to establish RACT requirements for that source in Colorado's ozone SIP.

Current SIP review

In 2009, the Commission submitted revisions to Regulation Number 7, Section XII. to EPA related to the 1997 ozone NAAQS attainment plan. In 2011, EPA approved the attainment demonstration but disapproved portions of the Regulation Number 7 revisions. In 2013, the Commission submitted revisions to Regulation 7, Section XII. to EPA to address EPA's disapproval. During the review of the 2013 submittal, EPA noted additional concerns with the monitoring, recordkeeping, and reporting requirements for natural gas processing plants and glycol natural gas dehydrators, as well as other concerns unrelated to the attainment demonstration for the SIP revision required following the reclassification of the DMNFR area to Moderate.

Natural gas processing plants

Regulation Number 7, Section XII.G.1. identifies a leak detection and repair ("LDAR") program applicable to natural gas processing plants. This "LDAR program" includes all applicable requirements in NSPS KKK. EPA has promulgated new LDAR programs for natural gas processing plants in NSPS OOOO and NSPS OOOOa. Therefore, the Commission updated references to applicable federal NSPS (i.e., NSPS OOOO and NSPS OOOOa) monitoring, recordkeeping, and reporting requirements for natural gas processing plants in the SIP.

Glycol natural gas dehydrators

Regulation Number 7, Section XII.H. already includes a 90% control requirement for glycol natural gas dehydrators. This is a SIP requirement. During the review of the 2013 submittal, EPA noted practical enforceability concerns with the monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators. Therefore, the Commission added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in the SIP to address EPA's concerns with ensuring compliance with the control requirement. The Commission based these requirements off of the Division's glycol natural gas dehydrator Operation and Maintenance Plan template to align the Section XII.H. monitoring, recordkeeping, and reporting requirements with the Operation and Maintenance Plan template, where possible. For any glycol dehydration system monitoring, recordkeeping and reporting requirement adopted for inclusion in the SIP during this hearing that conflicts with a similar provision in a Division approved Operation and Maintenance Plan, the Commission intends that sources only have to comply with the provision adopted for inclusion in the SIP and not the competing requirement in the approved Operation and Maintenance Plan. Further, the Commission directs the Division to work with industry to revise the Division's glycol dehydration systems Operating and Maintenance Plan template to remove requirements that are duplicative of the Section XII.H. monitoring, recordkeeping, and reporting requirements, to alleviate competing requirements with Section XII.H., as necessary.

EPA requested revisions

EPA also noted concerns with other previously submitted provisions in Section XII. EPA requested minor changes to Section XII.C.1.c., and a reversion to previously approved SIP language in Sections XII.C.1.d. and XIII.E.3.a. to address concerns with discretionary language. In response, the Commission revised Section XII.C.1.c. and reverted to previously approved SIP language in Sections XII.C.1.d. and XII.E.3.a., as requested by EPA.

Incorporation by Reference in Section XIX

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Section XIX.C through H by reference.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. The Commission also adopted revisions to Regulation Number 7 to address EPA concerns that are unrelated to the reclassification to Moderate. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address combustion device auto-igniters, condensate storage tank inspections, and glycol natural gas dehydrators at oil and gas facilities and equipment leaks at natural gas processing plants. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks and glycol natural gas dehydrators. For example, Regulation Number 7 addresses more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to tri ethylene glycol ("TEG") dehydrators. The Commission revised Regulation Number 7 to include glycol natural gas dehydrator monitoring, recordkeeping, and reporting requirements to ensure compliance with the current 90% system-wide control requirement in Section XII.D. Similarly, Regulation Number 7 addresses more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. Regulation Number 7 also addresses a broader set of storage tanks than NSPS OOOO and NSPS OOOOa, which address only those storage tanks with emissions greater than 6 tpy controlled actual emissions (i.e., 120 tpy uncontrolled actual emissions) and do not require auto-igniters on combustion devices. The Commission revised Regulation Number 7 to include the auto-igniter and condensate storage tank AVO inspections in Colorado's SIP to strengthen Colorado's SIP and support Colorado's 2017 emissions inventory. In addition, Regulation Number 7 addresses more equipment leaks at natural gas processing plants than NSPS KKK, which only applies to natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. The Commission revised Regulation Number 7 to reference the more recent equipment leak detection and repair requirements in NSPS OOOO and NSPS OOOOa.

The revisions to Regulation Number 7 also address RACT requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of VOC and NOx in Colorado's ozone nonattainment area. EPA published CTGs for lithographic and letterpress printing and industrial cleaning solvents in 2006. The Commission revised Regulation Number 7 to include regulatory RACT requirements for these VOC source categories. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission revised Regulation Number 7, Sections XVI. and XIX. to include source specific regulatory RACT requirements and a combustion process adjustment for combustion equipment at major sources of NOx. MACT DDDDD, MACT JJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with a lower ozone NAAQS in the near future. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Section XII. strengthen Colorado's SIP, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7 Sections X. and XIII. recognize products and practices currently utilized by printing and industrial cleaning solvent operations. The revisions to Regulation Number 7 Sections XVI. and XIX. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Section XII. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7 Sections X., XIII., and XVI. similarly establish the categorical RACT requirements for similarly situated and sized sources. Where a source is not subject to a categorical RACT requirement, RACT is, by its nature, determined on a case-by-case basis.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for auto-igniters, condensate storage tank inspections, and equipment leaks at natural gas processing plants. Other revisions reflect changes in industry practice and market forces, such as the VOC content of printing materials and cleaning solvents. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate Nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

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

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

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

P. November 16, 2017 Revisions to Section II., XII., Section XVII., and Section XVIII.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

<u>Basis</u>

On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate nonattainment area, Colorado must revise its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guideline ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a nonattainment area's attainment date. EPA finalized the Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado must further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado has similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions are not currently in Colorado's Ozone SIP. Therefore, the Commission is adopting RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP (Sections XII. and XVIII.). In order to make additional progress towards attainment of the NAAQS, the Commission is also adopting State Only revisions to require owners or operators of natural gas-driven pneumatic controllers in the DMNFR area to inspect and maintain pneumatic controllers.

Further, the Commission is making clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

Specific Statutory Authority

Section 25-7-105(1) of the Act directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of the Act. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program.

Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides the Commission broad authority to regulate hydrocarbons.

Purpose

As discussed, Colorado must adopt RACT into its Ozone SIP for sources covered by the Oil and Gas CTG. While the Oil and Gas CTG recommends presumptive RACT, it does allow states the flexibility to determine what constitutes RACT for the state's covered sources. Further, while EPA's Oil and Gas CTG implementation memorandum provides guidance that the emission controls determined by the state to be RACT for the sources covered by the Oil and Gas CTG must be implemented as soon as practicable but in no case later than January 1, 2021, states also have the flexibility to determine the appropriate implementation timeframe for the sources within the state's ozone nonattainment area. The Commission determined that some of Colorado's existing regulations (i.e., the "system-wide" control program for condensate tanks in Section XII.D.2.) achieve greater emission reductions than the RACT recommended by the Oil and Gas CTG. The Commission determined that some sources covered by the Oil and Gas CTG were not addressed in existing regulations (*i.e.*, pneumatic pumps).

The Commission also determined that some sources addressed in the Oil and Gas CTG (*i.e.*, components at well production facilities and natural gas compressor stations, compressors, pneumatic controllers) are already subject to existing regulations that were not yet part of Colorado's Ozone SIP. The Commission adopted many of these rules in 2014, and intends to preserve the substance of these rules, where possible, in moving them into the Ozone SIP, while making a few adjustments and improvements in response to recommendations in the Oil and Gas CTG. The Commission also adopted correlating revisions to the applicability provisions of Sections II. and XII.

The Commission relied on existing regulations in the Ozone SIP for RACT for condensate storage tank controls to satisfy Colorado's obligation to address storage vessels under the Oil and Gas CTG. The Commission adopted requirements for pneumatic pumps in Section XII. to address recommendations in the Oil and Gas CTG. The Commission revised the existing SIP requirements in Section XII.G. for equipment leaks at natural gas processing plants to address recommendations in the Oil and Gas CTG. The Commission duplicated into the Ozone SIP from Section XVII. provisions for compressors and leak detection and repair ("LDAR") for components at well production facilities and natural gas compressor stations. The Commission adjusted these LDAR requirements to address recommendations in the Oil and Gas CTG, along with updates to the recordkeeping and reporting requirements. Corresponding revisions to the LDAR program in Section XVII. are made on a State Only basis. The Commission also revised Section XVIII. to include existing State Only requirements for continuous bleed, natural gas-driven pneumatic controllers in the Ozone SIP and specify that continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants maintain a natural gas bleed rate of zero scfh.

The Commission adopted State Only provisions for the inspection and maintenance of natural gas-driven pneumatic controllers in Section XVIII.

The Commission also made clarifying revisions and corrected typographical, grammatical, and formatting errors found within the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

<u>Oil and Gas CTG, generally</u>

The Oil and Gas CTG provides recommendations for states to consider in determining RACT for certain oil and natural gas industry emission sources. EPA included storage vessels, pneumatic controllers, pneumatic pumps, compressors, equipment leaks, and fugitive emissions in the Oil and Gas CTG because EPA determined that these sources are significant sources of VOC emissions. EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." States may implement approaches that differ from the recommendations in the Oil and Gas CTG so long as they are consistent with the CAA, EPA's implementing regulations, and policies on interpreting RACT.

<u>Applicability to hydrocarbons (Section II.B.)</u>

Section II.B. currently exempts negligibly reactive volatile organic compounds, such as methane and ethane, from requirements of the SIP, while making hydrocarbon emissions, including methane and ethane, subject to State Only regulation under Sections XVII. and XVIII. Section XVII. sets a threshold for leaks requiring repair that is based on the concentration of hydrocarbons, as determined using EPA Method 21. Section XII.L. applies the same EPA Method 21 hydrocarbon threshold for leaks requiring repair. The Commission revised Section II.B. to clarify that the Section XII.L. hydrocarbon threshold and Section XVIII. natural gas emission standards serve only as VOC indicators and the SIP does not regulate hydrocarbon emissions.

The continuous bleed, natural gas-driven pneumatic controller requirements in Section XVIII. reduce natural gas emissions, which consists of other pollutants in addition to VOCs. Despite the presence of other constituents, natural gas is principally methane and the Commission intends to regulate emissions of natural gas as hydrocarbons, including methane and ethane, on a State Only basis as described in Sections II.B. and XVIII. The Oil and Gas CTG also utilizes a natural gas bleed rate standard for continuous bleed pneumatic controllers and the Oil and Gas CTG LDAR program employs a methane-based threshold for EPA Method 21 leak detection. Therefore, these revisions are consistent with the Oil and Gas CTG and the CAA.

While the revisions to Sections XII. and XVIII. to include provisions in Colorado's Ozone SIP are limited to the DMNFR, the Commission acknowledges the importance of reducing hydrocarbon emissions from the oil and gas sector (*i.e.*, upstream, midstream, and transmission) statewide. Therefore, without prescribing any particular outcome, the Commission directs the Division to initiate and lead a stakeholder process over the 2018-2019 timeframe to evaluate potential areas for cost-effective hydrocarbon emission reductions. Stakeholders will nominate topics for evaluation, which may include, but are not limited to, the frequency of LDAR inspections, transmission segment compressor emissions, natural gas-driven and zero emission pneumatic controllers outside the DMNFR (to be informed by the pneumatic study and inspection program), and potential expansion of the requirements adopted in the DMNFR as part of this rulemaking. The Division will brief the Commission on the stakeholder process in January 2019 and present recommendations for any new proposals for emission reductions by no later than January 2020. The Commission intends that one representative of industry, local government, and the environmental community each will have the opportunity to speak during the briefings.

<u>Applicability of Section XII. (Section XII.A.)</u>

The Commission is clarifying the applicability of Section XII. Historically, Section XII. has applied to operations that involve the collection, storage, or handling of condensate in the DMNFR. While this remains the case, the requirements in Section XII.J. for compressors, Section XII.K. for pneumatic pumps, and Section XII.L. for components at well production facilities and natural gas compressor stations also apply to those facilities and equipment collecting, storing, or handling other hydrocarbon liquids.

Section XII.A.5. further provides that subject well production facilities are those with uncontrolled actual VOC emissions greater than or equal to one ton per year ("tpy"). This applicability threshold addresses the Oil and Gas CTG's recommended barrels of oil equivalent ("BOE") exemption. EPA crafted the BOE exemption believing that well production facilities with an average production less than 15 BOE per well per day were inherently low emitting facilities. EPA later determined that information submitted on the draft CTG and proposed NSPS OOOOa did not support this conclusion. Therefore, in addition to the complications concerning tracking BOE, the Commission chose to rely upon an uncontrolled actual VOC tpy threshold for well production facility applicability. The use of a tpy threshold is also consistent with Colorado's current air pollutant reporting and permitting thresholds.

Further, Section XII.A. historically exempted from the requirements of Section XII. those operations reflecting a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the DMNFR area. That exemption continues to apply to Sections XII.B. through XII.I., but is not extended to Sections XII.J., XII.K., and XII.L.

<u>Definitions (Sections XII.B. and XVII.A.)</u>

The Commission is adopting definitions into Section XII.B., most of which are consistent with the existing definitions of Section XVII.

In the definition of "component", the Commission is clarifying both in Section XII.B. and in Section XVII.A., that thief hatches and other openings on storage tanks are included in the definition as a pressure relief device. This revision clarifies that leaks can occur from the thief hatch (*e.g.*, faulty or dirty seals) that are different than vented emissions under the standard in Section XVII.C.2.a., and that such leaks are subject to the LDAR program. The Commission anticipates that emissions from storage tanks identified as leaks requiring repair through the LDAR inspections under Sections XII.L. or XVIII.F. will be recorded and reported as leaks starting in 2018 for the 2019 annual report.

The Commission is adding a definition of "custody transfer" that applies to custody transfers of both natural gas and oil products. The Commission is also adding definitions for "natural gas driven diaphragm pump" and "natural gas processing plant" that correspond to federal definitions.

Operate without venting clarification (Section XVII.C.2.a.)

The Commission is providing additional detail concerning provisions adopted in 2014 that established an “operate without venting” standard for storage tanks. In response to industry concern that Section XVII. does not sufficiently define “venting” or delineate “venting” from “leaking,” the Commission is adopting provisions clarifying which emissions from storage tanks are considered “venting”. Section XVII.F. defines “leaking” in terms of infra-red camera or EPA Method 21 inspections of components. While storage tanks may also have leaks, as the Commission recognizes by including thief hatches or other openings on storage tanks in the definition of component, the Commission now further clarifies the “venting” standard by specifying that “venting” is emissions that are primarily the result of over-pressurization or that are from an open or visibly unseated pressure relief device (*e.g.*, thief hatch). The Commission intends that “visibly unseated” means visible from the outside of the pressure relief device and does not require an owner or operator to open a pressure relief device to determine if the seal is proper. The Commission also authorizes the Division to request a demonstration from the owner or operator that “venting” emissions observed by the Division were not primarily the result of over-pressurization. The Commission intends that such demonstration request allow an owner or operator to provide case specific information or other sufficient details that the design, operation, and maintenance of the facility is adequate to prevent over-pressurization. In clarifying a difference between “leaking” and “venting,” the Commission does not prohibit component leaks, per se, so long as leaks are repaired under the applicable repair time frames but does continue to prohibit “venting” from storage tanks.

Ozone season clarification (Sections XII.F.4. and XII.H.6.)

In October 2015, the EPA finalized a revision to the ozone NAAQS. (80 Fed. Reg. 65292 (Oct. 26, 2015)). In publishing its final rule, the EPA revised the length of Colorado’s ozone season. Colorado’s ozone season is now year-round, rather than the months of May through September. The Commission therefore revised references to “ozone season” in Sections XII.F.4. and XII.H.6. to reflect that the requirements now apply during the months of May to September. There are no substantive changes to the underlying requirements resulting from this revision.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Commission is updating the LDAR program applicable to equipment leaks at natural gas processing plants in the DMNFR by requiring owners or operators to comply with 40 C.F.R. Part 60 (NSPS), Subparts OOOO or OOOOa instead of complying with NSPS Subpart KKK, which is an earlier NSPS and less stringent. Subpart KKK requires sources to implement a NSPS Subpart VV level LDAR program, while Subpart OOOO requires sources to implement a NSPS Subpart VVa level LDAR program. A Subpart VVa level LDAR program is recommended for equipment at natural gas processing plants in the Oil and Gas CTG. The Commission determined that a 2019 implementation date would provide owners and operators of existing natural gas processing plants a reasonable period of time to establish and obtain the necessary resources to transition from Subpart KKK to Subpart OOOO LDAR requirements.

Compressors (Section XII.J.)

The Commission is adopting the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. into new Section XII.J. in order to include the requirements in Colorado’s Ozone SIP. The Commission is expanding the existing reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to address recommendations in the Oil and Gas CTG. Owners or operators of existing reciprocating compressors at natural gas processing plants must begin monitoring the reciprocating compressor hours of operation on January 1, 2018, starting at zero, in relation to the rod packing replacement requirement, conduct the first rod packing replacement prior to January 1, 2021, or route emissions to a process beginning May 1, 2018.

The Commission intends to allow owners or operators the option to reduce VOC emissions by routing centrifugal compressor emissions to a process or control and reciprocating compressor emissions to a process, consistent with the recommendations in the Oil and Gas CTG. With respect to centrifugal compressors, the Oil and Gas CTG and related federal requirements reveal that “process” generally refers to routing emissions via a closed vent system to any enclosed portion of a process unit (*e.g.*, compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Similarly, with respect to reciprocating compressors, routing to a process includes using a rod packing emissions collection system that operates under negative pressure and meets cover and closed vent system requirements. The negative pressure requirement ensures that all emissions are conveyed to the process and avoids inducing back pressure on the rod packing and resultant safety concerns. The Commission recognizes that there may a distinction between air pollution control equipment and process equipment (see e.g., U.S. EPA Letter to Timothy J. Mohin RE: Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment (Nov. 27, 1995)). For example, as noted in the Oil and Gas CTG, vapor recovery units and flow lines that “route emissions to a process” may be considered part of the process and not a control device, however, a related cover and closed vent system, if present, are still subject to applicable requirements. Further, components (as defined in these rules) located within a process or that are part of process equipment are subject to the Section XII.L. LDAR requirements. The Commission intends that owners or operators will follow similar procedures when complying with centrifugal and reciprocating compressor requirements in Section XII.J.

The Commission has adopted an inspection program for compressors, but also intends to provide owners or operators with the alternative of complying with other requirements, including the LDAR program adopted into Section XII.L. While the requirements of the LDAR program would replace the annual visual inspections and EPA Method 21 inspections of the cover and closed vent systems for defects and leaks, owners or operators would still need to conduct monthly inspections of their combustion devices. Compliance with the LDAR program is not limited to the inspection frequency and methods specified therein; owners or operators will also need to maintain records of the inspections and submit reports to the Division, consistent with the requirements of the LDAR program.

The Commission has specified an inspection and repair schedule for compressors, but has recognized that there may be reasons that a system is unsafe or difficult to inspect, or where a repair may not be feasible. Owners or operators will need to maintain records of each cover or closed vent system that is unsafe or difficult to inspect and schedule for inspection when circumstances allow. Similarly, when a repair is infeasible, insofar as it would require a shutdown of the equipment, repair can be delayed until the next scheduled shutdown but must be completed within two years after discovery. The Commission expects owners or operators to attempt to confirm repair before starting up operation after shutdown, to the extent practicable. The Commission also expects that if the repair attempt can be made during an unplanned shutdown, it will be.

The Commission adopts the monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

As an alternative to complying with the control, monitoring, and recordkeeping requirements in Section XII.J., owners or operators may instead comply with centrifugal or reciprocating compressor control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

<u>Natural gas driven diaphragm pumps (Section XII.K.)</u>

The Oil and Gas CTG contains recommendations for RACT for natural gas-driven diaphragm pumps. The Commission has not previously adopted regulations specifically directed at this type of equipment, and does so in Section XII.K.

The Oil and Gas CTG recommends that the pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG also recommends that owners or operators of pumps located at well sites route VOC emissions from the pneumatic pump to an onsite control device or process, unless the pneumatic pump operates on fewer than 90 days or an engineering assessment shows that routing the pneumatic pump emissions to a control device or process is technically infeasible. The assessment of technical feasibility may include safety considerations, distance from the control device, pressure losses and differentials in the closed vent system, gas pressure, and the capacity of the control device, among other things. The Commission acknowledges that RACT, by EPA definition, includes both technological and economic feasibility elements. The Commission determined that the cost of routing pneumatic pump emissions to an existing control device or process is reasonable and is, therefore, only providing an exemption from the emission control requirement based on technical infeasibility. However, the Commission does not intend to limit future RACT determinations due to limiting the pneumatic pump infeasibility analysis to technical ability. In addition, the 90-day exemption for pumps was included to address intermittently used or portable pumps. Consistent with the Oil and Gas CTG, the Commission intends that if a pump operates on any period of a calendar day, that day would be included in the calculation for applicability of the 90-day exemption.

The Commission does not expect an owner or operator to install new equipment specifically to route pneumatic pump emissions to a control or process but intends that when an owner or operator subsequently otherwise installs a control device or it becomes technically feasible to route pump emissions to a process, then the owner or operator will capture the emissions from the pneumatic pump and route the emissions to the newly installed control device or feasible process. Routing to a control or process generally refers to routing the emissions through a closed vent system to a vapor recovery unit, combustion device, or enclosed portion of a process where emissions are recycled and/or consumed.

The Commission has applied the same flexibility for pneumatic pumps as it has for compressors; owners or operators may comply with the inspection requirements in Section XII.K. or may follow the LDAR program in Section XII.L. Also similar to compressors, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak or equipment requiring repair so long as repair is completed within two years after discovery. As with compressors, the Commission expects owners or operators to attempt to confirm repair before starting up operation after a shutdown and make an attempt to repair during unscheduled shutdowns, to the extent practicable.

As an alternative to complying with the control, monitoring, recordkeeping, and reporting requirements in Section XII.K., owners or operators may instead comply with pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

<u>Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)</u>

The Oil and Gas CTG recommends LDAR programs at well sites (*i.e.*, well production facilities) and gathering and boosting stations (*i.e.*, natural gas compressor stations), including inspection frequencies, recordkeeping, and reporting. The Commission established Colorado's well production facility and natural gas compressor station LDAR program in 2014 in Section XVII.F., which is not part of the Ozone SIP. In creating a LDAR program in the Ozone SIP, the Commission intends to maintain as much of the current program as feasible. Where the Commission adopted revisions in Section XII.L. that differ from language currently found in the State Only LDAR program, the Commission in most cases made the same or similar revisions to the corresponding provisions in Section XVII.F.

Inspection, repair, and remonitoring

The Oil and Gas CTG recommends LDAR inspections at a minimum quarterly frequency for gathering and boosting stations and a minimum semi-annual frequency for well sites. The Commission is adopting inspection frequencies to address those recommendations in Section XII.L. The Commission is not modifying the LDAR schedules in Section XVII.F. The Commission intends that for those sources required by Section XVII.F. to conduct more frequent LDAR monitoring than specified in Section XII.L., the owner or operator may comply with Sections XII L.1. and XII.L.2. by complying with Sections XVII.F.3. and XVII.F.4. As with the LDAR inspection frequency in Section XVII.F., the Commission expects that owners or operators will ensure that inspections are appropriately spaced on the frequency schedules (*e.g.*, quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Oil and Gas CTG does not recommend a semi-annual LDAR inspection frequency at well sites with a gas to oil ratio less than 300 and which produce, on average, less than or equal to 15 BOE per well per day. The Commission recognizes that a component of RACT is balancing the emission reductions with the cost of the controls, and agrees that there should be a floor below which the recommended minimum frequency does not apply. The Commission determined a threshold of one tpy VOC emissions addresses this balance and the recommendation in the Oil and Gas CTG. Adopting an emissions based threshold maintains consistency with the current Regulation Number 7 applicability program and promotes the clarity and effectiveness of the regulation.

The Commission determined that annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy and semi-annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than six tpy address the Oil and Gas CTG's recommendations.

The Commission understands that the revised inspection frequencies will result in a significant number of new inspections. However, annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy will be less burdensome than semi-annual inspections. The Commission has determined that the emission reductions achieved by this program will improve the ability of the DMNFR area to attain the ozone standard and are cost-effective. While the rule specifies that the new inspection frequencies begin to apply as of June 30, 2018, the rule does not require that the first periodic inspection be completed by June 30, 2018. The Commission also does not require that monitoring be conducted in advance of this date; however, inspections done after January 1, 2018, that are in addition to current required LDAR monitoring frequencies may count towards the first annual or semi-annual inspection, or inspections done in the previous quarter at natural gas compressor stations. The Commission encourages owners or operators to conduct inspections prior to the 2018 summer ozone months to more effectively take advantage of the resulting emission reductions.

To ensure that the Ozone SIP LDAR program in Section XII.L. works with the existing State Only LDAR program in Section XVII.F., the Commission has maintained the same thresholds for identifying leaks that require repair. While the Oil and Gas CTG employs a methane concentration threshold when detected with EPA Method 21, Colorado's LDAR program uses a hydrocarbon concentration threshold. The Commission has also revised Section II. to clarify that Section XII.L. includes the use of hydrocarbons as an indicator of VOC emission reductions.

Concerning the use of non-quantitative instrument monitoring methods, the Commission adopted a quality assurance requirement that owners or operators maintain and operate such devices according to manufacturer recommendations. This requirement corresponds to recommendations in the Oil and Gas CTG concerning the maintenance and operation of OGI uses to detect fugitive emission components. The Commission intends for the Division to work with owners or operator to address any concerns that arise from manufacturer specifications for the maintenance of non-quantitative instrument monitoring methods.

Consistent with the current LDAR program in Section XVII.F., the Commission adopted a requirement to make a first attempt to repair an identified leak within five working (*i.e.*, business) days of discovery. In both Section XII.L. and in Section XVII.F., the Commission has included a requirement that repairs be completed within 30 days unless one of the existing justifications for delay of repair applies. As with compressors and pneumatic pumps, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak requiring repair so long as repair is completed within two years of discovery. The Commission has also maintained the flexibility of the State Only LDAR program in the SIP by giving owners or operators detecting leaks with a non-quantitative method (*e.g.*, IR camera) the ability to quantify the leaks within five working days. If the quantification shows that the leak must be repaired under Section XII.L.5., the deadline to repair runs from the date of discovery, not from the date of quantification.

As it did for Section XVII.F.7.c. in 2014, the Commission has also memorialized its intent, in Section XII.L.5.c., that operators not be subject to enforcement for leaks so long as operators are complying with the LDAR program requirements. However, as it also explained in 2014, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Section XII.C. For example, closing an open thief hatch within five days of an LDAR inspection does not shield an owner or operator from a possible violation of the requirement to minimize emissions to the maximum extent practicable.

Similarly, the Commission does not intend to relieve owners or operators of the obligation, on a State Only basis, to comply with the requirements of Section XVII., including the requirements in Sections XVII.B. and XVII.C.2. to minimize leakage to the extent reasonably practicable and operate without venting, respectively. However, the Commission does not intend these State Only provisions be enforceable under the Ozone SIP.

Recordkeeping and reporting

The Commission has determined that the current requirements did not adequately incentivize owners or operators to make all reasonable good faith efforts to obtain parts necessary to complete repairs. As a result, some leaks continued on delay of repair lists for an unreasonable length of time. Therefore, the Commission has determined that a review and record of such delays by a representative of the owner or operator is necessary for those occasions where unavailable parts have resulted in a delay of repair beyond 30 days.

The Commission expanded the recordkeeping for repair dates to include records of the type of repair method applied. The Commission determined this recordkeeping element aligns with recommendations in the Oil and Gas CTG and will more accurately inform repair activities. The Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of repair to ensure that owners and operators are consistently recording the information required.

The Commission also expanded the requirements for the annual LDAR report to ensure that the data submitted to the Division more accurately represents and summarizes the activities and effectiveness of the LDAR program. The Commission intends that the LDAR reports include the number of inspections, leaks requiring repair, leaking component type, and monitoring method by which the leaks were found – broken out by facility type (*i.e.*, inspection frequency tier of well production facility or natural gas compressor station).

The Commission intends that both the SIP and State Only LDAR reporting requirement can be satisfied by one report. The Commission expects that the first annual report containing the information required by these revisions will be submitted by May 31, 2019 (*i.e.*, no changes are expected to current requirements for the May 31, 2018, annual report representing leak detection and repair activities conducted during 2017).

Alternative approved instrument monitoring method ("AIMM")

The Commission has adopted a process for the review and approval of alternative instrument monitoring methods. The CAA prohibits a state from modifying SIP requirements except through specified CAA processes. EPA interprets this CAA provision to allow EPA approval of SIP provisions that include state authority to approve alternative requirements when the SIP provisions are sufficiently specific, provide for sufficient public process, and are adequately bounded such that EPA can determine, when approving the SIP provision, how the provision will actually be applied and whether there are adverse impacts. (State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction, 80 Fed. Reg. 33917-33918, 33927 (June 12, 2015)) Therefore, the Commission includes an application and review process in the SIP for the potential approval of instrument monitoring methods as alternatives to an infra-red camera or EPA's Method 21. The approval may also include modified recordkeeping and reporting requirements based on the capabilities of the potential alternative instrument monitoring method. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative AIMM must be capable of reducing emissions through the detection and repair of leaks comparable to the leaks detected and repaired as specified in the SIP to be potentially approvable.

The Commission received comments from stakeholders requesting that the Commission explicitly provide for the ability to employ certain alternatives not equipped with the leak detection capabilities of infra-red cameras or Method 21. These stakeholders emphasized that monitoring technologies are evolving rapidly and new technologies and monitoring programs are being developed that, when used on their own or in conjunction with other methods, may provide the same or better leak detection and repair results, at potentially lower costs. The process outlined in Section XII.L.8. requires an applicant to demonstrate that the proposed alternative monitoring achieves emission reductions that are at least as effective as the leak detection and repair program in Section XII.L. The Commission intends that the rule be flexible enough to allow the Division to consider such alternative monitoring methods or programs, as long as the applicant can demonstrate that the proposed method or program achieves emission reductions that are as effective as other approved technologies or methods. To make this demonstration, an applicant may consider demonstrating that a program of alternative inspection frequencies, pollutants detected, or leak thresholds for repair achieves emission reductions comparable to the inspection frequencies and leaks requiring repair thresholds in Section XII.L., thus the consideration of an alternative leak detection program. The Commission recognizes that current, established approaches or methodologies to evaluate the performance of alternative monitoring technologies and programs as compared to baseline monitoring technologies (infra-red camera, EPA Method 21) do not yet exist. However, such methodologies are being developed.

For example, the Interstate Technology and Regulatory Council (ITRC), in which Colorado participates, is developing, but has not yet published, a guidance document to establish, if possible, a consensus for evaluating and comparing the effectiveness of leak detection technologies. While the criteria for evaluating the effectiveness of an alternative program as compared to the base program is being developed, alternative monitoring method applicants may submit an application for approval of an alternative monitoring method but must be prepared to present a robust and complete evaluation of the technology or program's performance that allows for comparison to the base technologies in the SIP. It is possible the Division may delay consideration and final determination regarding an alternative monitoring method or program application until established comparison criteria are developed or submitted. Taking into account the deliberations of the ITRC process, the Commission expects that the Division will consider complete applications in a timely manner.

The Commission also received comments from stakeholders requesting that the Commission clarify EPA's participation regarding potential alternative monitoring methods. As discussed, the Commission believes that the process to review and potentially approve alternative monitoring methods is sufficiently constrained such that EPA, when approving the process, can be assured as to what emission reductions any such alternative monitoring will achieve in the context of the Section XII.L. LDAR program. However, the Commission also recognizes EPA's technical knowledge and is requiring the Division to continue to engage with EPA concerning alternative monitoring methods. Specifically, the Division must provide complete applications to EPA early in the review process, which has previously ranged from three to nine months. The Division must also provide EPA six (6) months after approval of an alternative for further EPA review. The Commission believes this process provides sufficient time for meaningful engagement with EPA.

Clarifications

The Commission is clarifying, both in Section XII.L. and Section XVII.F., that all detected emissions are leaks, but that only those leaks above specified thresholds require repair. The Commission did not intend that leaks falling below the specified thresholds would not be considered "leaks," only that those leaks did not require repair in accordance with the prescribed schedules. The Commission has further clarified that only records of leaks requiring repair need to be maintained.

Regulation Number 7 already requires that owners or operators remonitor repaired leaks with an AIMM. AIMM includes EPA Method 21, which includes the soapy water method, and the Commission further clarifies that an owner or operator may use the soapy water method in EPA Method 21 to remonitor a repaired leak.

Some stakeholders asked the Commission to "clarify" that the LDAR repair, remonitoring, recordkeeping, and reporting requirements applied only to those leaks discovered by the owner or operator, and not those discovered by the Division. The Commission believes that would not be a clarification, but a change to the current program, and does not make that requested revision at this time. Therefore, the repair, remonitoring, recordkeeping, and reporting requirements continue to apply to leaks discovered by the Division.

<u>Pneumatic controllers (Section XVIII.)</u>

The Commission is adopting both Ozone SIP and State Only revisions to Section XVIII.

The Commission added definitions of continuous bleed and intermittent pneumatic controller. The Commission also added "continuous bleed" to several provisions throughout Sections XVIII.C. through XVIII.E. to clarify that the provisions adopted in 2014 primarily applied to continuous bleed pneumatic controllers (which emit continuously) as opposed to intermittent pneumatic controllers (which emit only when actuating).

Pneumatic controllers at or upstream of natural gas processing plants

Section XVIII. already requires that owners or operators install low-bleed pneumatic controllers at or upstream of natural gas processing plants, unless a high-bleed pneumatic controller is required for safety or process purposes. This requirement is consistent with the Oil and Gas CTG and the Commission intends that these provisions be included in Colorado's Ozone SIP.

The Commission adopts additional requirements, consistent with the Oil and Gas CTG, related to pneumatic controllers at natural gas processing plants. The Commission is requiring that all continuous bleed, natural gas-driven pneumatic controllers at a natural gas processing plant have a bleed rate of zero (*i.e.*, no VOC emissions), unless a pneumatic controller with a bleed rate greater than zero is necessary due to safety and process reasons. To satisfy this requirement, owners or operators of natural gas processing plants could, for example, drive pneumatic controllers with instrument air, use mechanical or electrically powered pneumatic controllers, or use self-contained pneumatic controllers that release natural gas to a downstream pipeline instead of to the atmosphere. The requirements to submit a justification for a pneumatic controller exceeding the emission standard to the Division, as well as the requirements for tagging and records, duplicate and are intended to be consistent with existing requirements related to high-bleed pneumatic controllers. The requirement to maintain pneumatic controllers exceeding the applicable emission standard are also duplicated from the existing high-bleed maintenance requirement, but revised to include the suggested maintenance actions specifically in the applicable provisions, instead of referring to an “enhanced maintenance” definition. The Commission revised the maintenance requirement in this manner to separate the actions taken to maintain a pneumatic controller exceeding the applicable emission standard from the, potentially very similar, actions taken to return a pneumatic controller to proper operation. For example, the owner or operator of a high-bleed pneumatic controller or a pneumatic controller with a bleed rate greater than zero at a natural gas processing plant is required to perform specified maintenance on the pneumatic controller regardless of whether or not the pneumatic controller is determined to be properly operating. In contrast, the owner or operator of a pneumatic controller inspected under Section XVIII.F. must conduct enhanced response to return that pneumatic controller to proper operation.

Additionally, the Commission is requiring owners or operators to maintain records demonstrating their continuous bleed, natural gas-driven pneumatic controllers meet the applicable low-bleed or bleed rate of zero standards. These records are also intended to inform the extent to which continuous bleed pneumatic controllers are used in the DMNFR. The Commission understands that the number of continuous bleed, natural gas-driven pneumatic controllers in use by an operator can change frequently, and is not requiring a running log or count of each individual pneumatic controller.

The Commission adopted these recordkeeping requirements with the expectation that owners or operators can keep records including, but not limited to, site-specific documentation of continuous bleed, natural gas-driven pneumatic controllers such as manufacturer specifications, engineering calculations, field test data, or documentation of a company’s continuous bleed, natural gas-driven pneumatic controller purchase and installation program ensuring that any such pneumatic controller meets the applicable bleed rate standard.

Clarification

The Commission is also clarifying the intent behind provisions adopted in 2014 regarding the use of pneumatic controllers powered by instrument air (as opposed to natural gas) when grid power is being used. In 2014, the Commission intended that when a pneumatic controller was proposed for installation, owners or operators would power the pneumatic controller via electrical power instead of natural gas when electrical grid power was being used on-site. The provisions adopted in 2014 allowed owners or operators to install a pneumatic controller with VOC emissions equal to or less than a low-bleed pneumatic controller in some situations. The Commission has learned that some owners or operators interpret the rule as providing the option of installing either no-bleed or low-bleed pneumatic controllers in all situations.

Even though the Commission believes its intent was clear, the Commission recognizes that the rule could fairly be described as ambiguous and that there is a good faith legal argument for the alternative interpretation. The Commission is revising the rule to clarify that where electric grid power is being used on site and it is technically and economically feasible to install no-bleed pneumatic controllers, any newly installed pneumatic controllers must be no-bleed. Where the owner or operator determines it is not technically and economically feasible to install a no-bleed pneumatic controller, the owner or operator may install a low-bleed or intermittent pneumatic controller.

The Commission recognizes that the installation of an electrically-powered controller may have been feasible in 2014, but may not be feasible to retrofit at this time. The Commission nonetheless encourages owners or operators statewide who, based on a misreading of the regulation, did not install a no-bleed pneumatic controller to evaluate whether retrofitting controllers – with no-bleed or self-contained pneumatic controllers – at this time is technically and economically feasible. The Commission also encourages owners and operators statewide to install, or retrofit with, no-bleed or self-contained pneumatic controllers at locations across the state, even where on site electrical grid power is not available to the extent there is no significant air quality disbenefit in doing so.

Natural gas driven pneumatic controller inspection and enhanced response (State Only)

Following the 2014 rulemaking, the Commission requested that the Division continue its investigation into potential regulations for intermittent pneumatic controllers. During the recent 2016 ozone rulemaking, stakeholders again asked the Commission to address intermittent pneumatic controllers. In response, the Commission again directed the Division to evaluate potential emission reduction measures for intermittent pneumatic controllers.

The Commission is adopting an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven pneumatic controllers. While the Oil and Gas CTG notes the value of pneumatic controller inspection and maintenance, the Oil and Gas CTG does not specify a pneumatic controller inspection and maintenance as presumptive RACT. Therefore, while the Commission determined that these revisions are technically and economically feasible, the revisions are proposed as State Only in the DMNFR and are not made part of the Ozone SIP at this time. Natural gas-driven pneumatic controllers include continuous bleed, intermittent, and self-contained pneumatic controllers. Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere.

The Oil and Gas CTG suggests that maintenance of pneumatic controllers, including cleaning and tuning, can eliminate excess emissions from the devices. While the Oil and Gas CTG's recommended RACT (low-bleed or zero emissions) applies to continuous bleed, natural gas-driven pneumatic controllers, the discussion concerning enhanced maintenance of pneumatic controllers builds on earlier EPA discussions, such as EPA's 2014 Pneumatic Controller White Paper, and is not limited to continuous bleed pneumatic controllers. The Commission recognizes that continuous bleed and intermittent pneumatic controllers are designed to have emissions, however these pneumatic controllers can also have excess emissions when not operating properly. As a result, the Commission believes that a pneumatic controller inspection and response program will reduce the excess emissions from such pneumatic controllers.

The Commission intends to apply the same find and fix approach used in the LDAR requirements in Sections XII.L. and XVII.F. to all natural gas-driven pneumatic controllers in the DMNFR. The Commission is requiring that natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the pneumatic controller is operating properly, in contrast to quantitatively comparing pneumatic controller emissions to a regulatory threshold. The Commission is requiring that owners or operators inspect pneumatic controllers at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

The Commission expects that owners or operators will inspect their pneumatic controllers during the same LDAR inspections, and using the same AIMM, conducted for compliance with Sections XII.L. or XVII.F. The pneumatic controller inspection and enhanced response process is intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven pneumatic controller using AIMM to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those pneumatic controllers with detected emissions. Second, the owner or operator must determine whether the pneumatic controllers with detected emissions are operating properly. Use of an AIMM is not required during this second step; the Commission does not at this time intend to mandate to owners or operators how to determine if their pneumatic controllers are operating properly. During this second step, if an owner or operator determines that the pneumatic controller is operating properly, no further action is necessary. Third, where an owner or operator determines the pneumatic controller is not operating properly, the owner or operator must take actions to return an improperly operating pneumatic controller to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those pneumatic controllers that the owner or operator determined not to be operating properly.

Similar to the LDAR records, owners or operators must keep records of the date the pneumatic controller was returned to proper operation and a description of the types of actions taken. As with well production facility and natural gas compressor station LDAR records, the Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of response actions to ensure that owners and operators are consistently recording the information required. The Commission expects that owners or operators will include the pneumatic controller information as State Only information in their LDAR annual reports. In returning a pneumatic controller to proper operation, the Commission relies upon the previously defined term, now enhanced response, found in Section XVIII.B. related to maintaining high-bleed pneumatic controllers. The Commission has expanded this definition to guide responsive activities concerning all natural gas-driven pneumatic controllers. Recognizing that the function and potential maintenance or repair of pneumatic controllers can be variable, owners or operators are not restricted to using an AIMM to determine proper operation or verify the return to proper operation.

The Commission has adopted a “reassessment” provision for this inspection and enhanced response program following a Division led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The Commission also recognizes that owners and operators may currently have limited information on “good engineering and maintenance practices” for pneumatic controllers and intends that more information on these practices will be gathered during the pneumatic study and implementation of Section XVIII.F. to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry’s proposal, a task force will be convened by January 30, 2018, consisting of representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection will begin no later than by May 1, 2018. The task force will brief the Commission annually and make any recommendations on its findings in a report to the Commission, due May 1, 2020. The Commission intends that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the Commission. The Commission intends that this information be used to reassess the natural gas-driven pneumatic controller requirements of Section XVIII.F. Section XVIII.F. will remain in effect until rescinded, superseded, or revised.

The Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers, which highlights the need for the reassessment of Section XVIII.F. as well as enforcement discretion. The Commission intends that while the task force is actively working on data collection and the 2020 report to the Commission, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator. Any information gathered through the task force, including on preventative, good engineering, and maintenance practices, will be used to reassess Section XVIII.F. and will not be used for enforcement purpose through 2020.

Additional Considerations

Colorado must revise Colorado's Ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. The Commission carefully considered what provisions to include in Colorado's Ozone SIP, especially given Colorado's pre-existing emission control requirements that address most of the same sources addressed by the Oil and Gas CTG, yet do so differently. Some of these pre-existing requirements were adopted into Colorado's SIP and some will remain as State Only requirements. In determining what existing provisions would be included in Colorado's Ozone SIP, the Commission considered: 1) whether or not Colorado had existing emission control measures for the same sources covered by the Oil and Gas CTG; 2) whether these existing requirements were already adopted for inclusion in the Ozone SIP; and 3) the degree of emissions reductions achieved by any existing Colorado emission control measures in comparison to the Oil and Gas CTG. In resolving differences between existing Colorado provisions and the Oil and Gas CTG, preference was given to existing Colorado provisions, especially those already incorporated into Colorado's Ozone SIP and Colorado's existing regulatory framework. For example, the Commission relied upon existing storage tank requirements already adopted into Colorado's Ozone SIP. In the case of well production facility LDAR, the Commission adopted a tpy applicability threshold in place of the Oil and Gas CTG's BOE threshold, which applies to more sources than the Oil and Gas CTG, yet adopted a less frequent inspection frequency into the Ozone SIP for the smaller facilities than the Oil and Gas CTG.

In determining whether or not any additional requirements would be relied upon in establishing RACT in Colorado's Ozone SIP for the oil and gas sector, the Commission determined whether or not the emission control measures were necessary for the ozone attainment demonstration. In the case of LDAR for pneumatic controllers at well production facilities and natural gas compressor stations, the Commission adopted emission control measures as State Only measures given the need to obtain emission reductions as well as more information on this source type. These examples illustrate the Commission's careful consideration of what provisions to include in Colorado's Ozone SIP.

The CAA requires that Colorado's Ozone SIP include RACT for all sources covered by a CTG, such as the emission sources addressed in the Oil and Gas CTG. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs.

The Commission is also revising certain State Only regulations to reduce emissions and promote attainment of current federal ozone standards. Specifically, the Commission is adopting requirements related to the inspection of natural gas-driven pneumatic controllers at oil and gas facilities. As discussed, malfunctioning pneumatic controllers can result in significant hydrocarbon emissions. The DMNFR ozone nonattainment area is currently classified as a Moderate nonattainment area under the 2008 ozone NAAQS. The deadline for the DMNFR to attain the 2008 ozone NAAQS is July 2, 2018. If the DMNFR does not attain the standard or does not receive an extension, EPA may reclassify the DMNFR as a Serious nonattainment area under the 2008 ozone NAAQS. In addition, the Commission approved a designation recommendation for the DMNFR under the 2015 ozone NAAQS in September 2016.

While EPA has not yet acted on this recommendation, the Commission expects the DMNFR will be designated as nonattainment under the 2015 ozone NAAQS and is taking action to promote attainment of the more stringent standard. Given both the potential for a reclassification to Serious under the 2008 ozone NAAQS and the need to reduce ozone to meet the more stringent 2015 ozone NAAQS, the Commission is adopting the State Only pneumatic controller inspection requirements that further reduce ozone precursors emissions, notwithstanding the fact that a pneumatic controller inspection program is not specified as presumptive RACT in the Oil and Gas CTG.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission. The EPA revised the ozone NAAQS in 2015 and the DMNFR must attain the new standard or face additional requirements. The revisions to Regulation Number 7 address RACT for compressors, pneumatic pumps, pneumatic controllers, natural gas processing plants, natural gas compressor stations, and well production facilities. The revisions apply to equipment already regulated by Colorado on a State Only basis and apply to equipment not previously subject to regulation. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to the regulated equipment. The Commission determined that the adopted RACT SIP requirements are comparable to the Oil and Gas CTG's recommendations. The Commission also determined that there are not comparable federal rules requiring the inspection and maintenance of natural gas-driven pneumatic controllers.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa to allow an owner or operator to request EPA approve compliance with an alternate emission limitation (e.g., alternative monitoring, state program) instead of related requirements in NSPS OOOOa.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here. Further, the State Only pneumatic controller inspection requirements address the lack of federal requirements concerning emissions from malfunctioning pneumatic controllers.

(IV) Unless federal law changes, Colorado will be required to comply with the more stringent 2015 ozone NAAQS in the near future and may be required to comply with the more stringent requirements for a Serious nonattainment area. These current SIP and State Only revisions may improve the ability of the regulated community to comply with new, more stringent, future requirements. In addition, these revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommended oil and gas RACT provisions.

(V) EPA has established October 27, 2018, deadline for this SIP submission. EPA has not yet established deadlines for the DMNFR to attain the 2015 ozone NAAQS. However, given the potential reclassification of the DMNFR to Serious under the 2008 ozone NAAQS, the Commission determined that taking action to reduce ozone precursor emissions as soon as practicable, either as part of the SIP or on a State Only basis, is warranted.

(VI) The revisions to Regulation Number 7 Sections XII. and XVIII. strengthen Colorado's SIP and State Only provisions, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(VII) The revisions to Regulation Number 7 Sections XII. and XVIII., including the State Only provisions, establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, or qualify for an extension of the attainment deadline, EPA will likely reclassify Colorado as a Serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs. The State Only rule revisions are expected to reduce future costs by achieving emissions reductions that will assist the DMNFR in attaining both the 2008 and 2015 ozone NAAQS thus avoiding additional ozone nonattainment area CAA requirements.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The State Only pneumatic controller inspection program is tailored to be consistent with the SIP required LDAR program, thereby reducing costs related to pneumatic controller inspections.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants. Further, pneumatic controller inspections will be conducted using accepted technologies and some owners or operators already repair and maintain pneumatic controllers.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP. The Commission determined that the Division's proposal was reasonable and cost-effective. The Commission further determined the State Only natural gas-driven pneumatic controller inspection program is reasonable and cost-effective, given the potential for reducing emissions from malfunctioning pneumatic controllers and the absence of federal requirements addressing pneumatic controller emissions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's Ozone SIP to address the Moderate nonattainment area requirements. Colorado must also continue to reduce ozone concentrations to address both the possibility of reclassification under the 2008 ozone NAAQS and the 2015 ozone NAAQS. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, including regulatory changes made on a State Only basis, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC.

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

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

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

Q. July 19, 2018 (Sections XVI. and XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e. sources that emit or have the potential to emit 100 tons per year ("tpy") or more). The CAA does not define RACT. However, EPA has defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53762 (Sept. 17, 1979). RACT can be adopted in the form of emissions limitations or work practice standards or other operation and maintenance requirements as appropriate.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions. In response to the reclassification, the Commission revised Regulation Number 7 to satisfy RACT SIP requirements for Moderate nonattainment areas by establishing categorical RACT requirements for major sources of VOC and/or NOx in the DMNFR. Specifically, the Commission adopted RACT requirements in Section XVI.D. for existing boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces, and compression ignition reciprocating internal combustion engines ("RICE") (collectively referred to as "stationary combustion equipment") located at major sources of NOx in the DMNFR as of June 3, 2016. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Major VOC and NOx source RACT

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. The following sources were known by the Commission to be major sources of VOC and/or NOx as of June 3, 2016 and were analyzed in Colorado's Moderate Area SIP for the 2008 8-Hour Ozone NAAQS:

Anheuser-Busch, Fort Collins Brewery (069-0060) and Nutri-Turf (123-0497) (major for VOC and NOx)

Ball Metal Beverage Container Corporation (059-0010 major for VOC)

Buckley Air Force Base (005-0028 major for NOx)

Carestream Health (123-6350 major for NOx)

Cemex Construction Materials (013-0003 major for VOC and NOx)

Colorado Interstate Gas, Latigo (005-0055 major for NOx)

Colorado Interstate Gas, Watkins (001-0036 major for VOC and NOx)

Colorado State University (069-0011 major for NOx)

CoorsTek (059-0066 major for VOC)

Corden Pharma Colorado (013-0025 major for VOC)

DCP Midstream, Enterprise (123-0277 major for VOC and NOx)

DCP Midstream, Greeley (123-0099 major for VOC and NOx)

DCP Midstream, Kersey/Mewbourn (123-0090 major for VOC and NOx)

DCP Midstream, Lucerne (123-0107 major for VOC and NOx)

DCP Midstream, Marla (123-0243 major for VOC and NOx)

DCP Midstream, Platteville (123-0595 major for VOC and NOx)

DCP Midstream, Roggen (123-0049 major for VOC and NOx)

DCP Midstream, Spindle (123-0015 major for VOC and NOx)

Denver Regional Landfill, Front Range Landfill, Timberline Energy (123-0079 major for NOx)

Elkay Wood Products (001-1602 major for VOC)

IBM Corporation (013-0006 major for NOx)

Kerr-McGee Gathering, Frederick (123-0184 major for VOC and NOx)

Kerr-McGee Gathering, Hudson (123-0048 major for VOC and NOx)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057 major for VOC and NOx)

Kodak Alaris (123-0003 major for VOC)

Metal Container Corporation (123-0134 major for VOC)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery, Rocky Mountain Metal Container (059-0006), MMI/EtOH (059- 0828), and Colorado Energy Nations Company, LLC (059-0820) (major for VOC and NOx)

Owens-Brockway Glass (123-4406 major for NOx)

Phillips 66 Pipeline, Denver Terminal (001-0015 major for VOC)

Plains End (059-0864 major for VOC and NOx)

Public Service Company, Cherokee (001-0001 major for NOx)

Public Service Company, Denver Steam Plant (031-0041 major for NOx)

Public Service Company, Fort Lupton (123-0014 major for NOx)

Public Service Company, Fort Saint Vrain (123-0023 major for NOx)

Public Service Company, Rocky Mountain Energy Center (123-1342 major for NOx)

Public Service Company, Valmont (013-0001 major for NOx)

Public Service Company, Yosemite (123-0141 major for NOx)

Public Service Company, Zuni (031-0007 major for NOx)

Rocky Mountain Bottle Company (059-0008 major for NOx)

Sinclair Transportation Company, Denver Terminal (001-0019 major for VOC)

Spindle Hill Energy (123-5468 major for NOx)

Suncor Energy, Commerce City Refinery Plants 1, 2, and 3 (001-0003 major for VOC and NOx)

Thermo Cogeneration, JM Shafer (123-0250 major for NOx)

Tri-State Generation, Frank Knutson (001-1349 major for NOx)

TRNLWB, LLC (Trinity Construction Materials, Inc.) (059-0409 major for NOx)

University of Colorado Boulder (013-0553 major for NOx)

WGR Asset Holding, Wattenberg (001-0025 major for VOC and NOx)

Many of the major sources listed are subject to regulatory RACT requirements. Some of the sources or source emissions points are subject to regulatory RACT requirements in Colorado’s SIP; other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement of inclusion of an applicable federal New Source Performance Standards (“NSPS”) or National Emission Standard for Hazardous Air Pollutants (“NESHAP”). However, as a Moderate nonattainment area, Colorado must include in the SIP, provisions to implement RACT for Colorado’s major sources. During the November 17, 2016 rulemaking, the Commission adopted source specific RACT for a number of major sources of VOC and/or NOx (again greater than or equal to 100 tons per year) in the DMNFR. These were originally adopted as Sections XIX.C.-XIX.G. for stationary combustion turbines, stationary internal combustion engines, wood furniture manufacturing, and municipal landfills, respectively, during the November 17, 2016 rulemaking. These sections have changed to Sections XVI.D.4.b. and XIX.A.-D. during this July 19, 2018 rulemaking, where requirements for stationary combustion turbines were removed and consolidated into Section XVI.D.4.b. The original Section XIX.C.-XIX.G. RACT requirements became effective on January 1, 2017. However, during the November 17, 2016 rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Regulation 3, Part F. Therefore, the Commission opted to adopt RACT for Colorado’s existing major sources of NOx on a categorical basis in this July 19, 2018 rulemaking.

Establishing RACT on a categorical basis is a distinctly different process from Colorado’s minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process), and the designs of which can more easily accommodate changes prior to construction. Categorical RACT applies much more broadly to source category, including both existing sources/equipment and new/modified sources/equipment. This inclusion of existing equipment significantly impacts costs, as those sources are not already committed to a capital expenditure and any associated shut down to add controls. This ultimately impacts the decision on what controls are determined to be reasonably available, technologically and economically feasible for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement.

To determine RACT on a categorical basis, the Commission required specific owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NOx emissions from the facility or emission point(s), propose RACT for that facility or point(s), propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). The following major sources were required to submit RACT analyses:

Anheuser-Busch (069-0060) – emission points equal to or greater than 2 tpy VOC or 5 tpy NOx

Buckley Air Force (005-0028) – engines and engine test cell (pt 102, 103, 104, 105, 101)

Carestream Health (123-6350) – boilers (pt 004)

Colorado Energy Nations Company, LLC (059-0820) – boilers (pt 001, 002)

Colorado Interstate Gas, Latigo (005-0055) – engines (001, 011)

Colorado Interstate Gas, Watkins (001-0036) – engines (001, 002)

Colorado State University (069-0011) – boilers (pt 003, 005, 007, 013)

IBM (013-0006) – engines and boilers (pt 088, 090, 001, 011, 095)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057) – turbine (pt 052) and engines (pt 038 through 044, and 047 through 049)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery (059-0006) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

MMI/EtOH (059-0828) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Nutri-Turf (123-0497) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Owens-Brockway (123-4406) – emission points with emissions equal to or greater than 5 tpy NOx (pt 001-023, 025)

Public Service Company, Cherokee (001-0001) – turbines (pt 028, 029)

Public Service Company, Fort Saint Vrain (123-0023) – turbines (pt 010, 011, 001)

Public Service Company, Denver Steam Plant (031-0041) – boilers (pt 001, 002)

Public Service Company, Zuni (031-0007) – boilers (pt 001, 002, 003)

Public Service Company, Fort Lupton (123-0014) – turbines (pt 001, 002)

Public Service Company, Valmont (013-0001) – turbine (pt 002)

Rocky Mountain Bottle (059-0008) – glass melt furnaces (pt 001)

Suncor (001-0003) – boilers (pt 309, 019, 021, 023)

Tri-State Generation and Transmission, Frank Knutson (001-1349) – turbines (pt 001, 003)

TRNLWB, LLC (Trinity Construction Materials) (059-0409) – shale kiln (pt 001)

University of Colorado (013-0553) – Power House and East District – boilers (pt 001, 002, 012, 013) and Williams Village– boilers (pt 016, 017)

WGR Asset Holding, Wattenberg (001-0025) – boiler (pt 012), turbine and duct burner (pt 021) and engines (pt 004 and 018)

Based on the information provided in these RACT analyses as well as the Division's own in-depth review of rules adopted by Moderate nonattainment areas in other states and EPA guidance such as the RACT/BACT/LAER Clearinghouse, the Commission adopted RACT requirements in Section XVI.D. for stationary combustion equipment located at existing major sources of NOx in the DMNFR. The requirements of Section XVI.D. only apply to existing stationary combustion equipment located at sources in the DMNFR that were major for NOx as of June 3, 2016 (i.e. the effective date of the DMNFR's reclassification to Moderate nonattainment).

Definitions

The definition for "stationary combustion equipment" refers to individual emission points and not grouped emission points.

Emission limitations and operational requirements

The Commission adopted categorical emission limitations (Section XVI.D.4.), which vary based on fuel type and size of the stationary combustion equipment, where applicable. Affected stationary combustion equipment is required to comply with these exemptions by October 1, 2021. This compliance period is necessary in order to allow affected sources sufficient time to complete any capital expenditures, install any control or monitoring equipment, and/or satisfy any permitting requirements necessary to comply with the applicable emission limitation. The heat input size threshold for determining whether an emission limitation applies refers to the maximum design value of the stationary combustion equipment. De-rated heat input is not the equivalent of maximum design value heat input. Therefore, stationary combustion equipment cannot simply de-rate to fall below the size threshold. For certain categories of stationary combustion equipment, if the equipment's heat input is below the applicability threshold for the emission limitations, then the equipment would still be required to comply with the combustion process adjustment requirements originally adopted by the Commission during the November 17, 2016 rulemaking (now in Section XVI.D.6.) The compliance date for the categorical emission limits (i.e. XVI.D.4 and XVI.D.5) is independent of the compliance date for the combustion process adjustment (i.e. XVI.D.6(b)(vi)(A)).

The combustion process adjustment requirements shall apply as RACT to a particular piece of equipment in accordance with the applicability provision, Section XVI.D.6.a., regardless of whether or not that piece of equipment is subject to a categorical emission limit in Section XVI.D.4. As described in Section XVI.D.6.a., the combustion process adjustment requirements only apply to stationary combustion equipment with uncontrolled actual emissions of NOx equal to or greater than 5 tons per year located at major sources of NOx. For stationary combustion turbines, the heat input capacity threshold for the emission limitations takes into account to the heat input capacity of the stationary combustion turbine only and not the heat input capacity of the stationary combustion turbine and any duct burner that may be used.

For glass melting furnaces at major sources of NOx, the Commission adopted a production-based categorical emission limitation (Section XVI.D.4.d.). Emissions from some glass melting furnaces are routed through a common stack, where total emissions from multiple furnaces are monitored on a continuous basis. Where this is the case, the total emissions, as monitored from the common stack, shall be divided by the total glass production from all glass melting furnaces associated with the common stack to demonstrate compliance with the categorical RACT limit.

Exemptions

The Commission determined several exemptions from compliance with the categorical RACT standards to be appropriate for Colorado’s source mix. In Section XVI.D.2.a., the Commission adopted a 20% capacity factor exemption for boilers and a 10% capacity factor exemption for stationary combustion turbines and compression ignition reciprocating internal combustion engines. The Commission established the 20% and 10% capacity factor exemptions, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units. The Commission determined that the capacity factor exemptions addressed each of these concerns, and thus that additional individual exemptions were not necessary beyond the capacity factor exemption.

At low capacities, controls are often cost prohibitive or technologically infeasible. The Commission determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the categorical standard or monitoring requirements. Many of the older boilers are not equipped with continuous emission monitoring systems (“CEMS”) and may require add-on controls to comply with the categorical standard. The shift in capacity to newer, lower emitting boilers which are already equipped with NOx controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption for boilers provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall environmental benefit.

Some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating (“MCR”). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular low utilization boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard.

The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard runs contrary to the original intent of reducing emissions, thus the Commission concludes that it is reasonable to allow exclusion of limited-use boilers from the categorical standard and associated CEMS requirements, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with the categorical standard. Consequently, the Commission determined that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.

For stationary combustion turbines and compression ignition RICE, a 10% capacity factor exemption from the proposed categorical emission standards and monitoring requirements is appropriate because combustion turbines and compression ignition RICE are more likely to operate during the summer months. Moreover, for turbines and compression ignition RICE that are used primarily for emergency power generation or peak demand, historic capacity factors are extremely low (0%-5%), and a 10% capacity factor exemption will provide enough operational flexibility to respond to emergency and peak demand events.

Separately, the categorical RACT for glass melting furnaces provides a 35% low usage allowance similar to capacity factor.

The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input. Alternatively, for electric generating units, the proposal allows for capacity factor to be determined based on electric output, which is consistent with the federal Acid Rain Program.

The Commission intended that the exemption for stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx was based on the permitting threshold in Regulation 3. Similarly, this equipment was not exempted from having to undergo a RACT analysis. The owner or operator must use the most recent air pollution emission notice ("APEN") submitted to the Division to determine total uncontrolled actual emissions.

Stationary combustion equipment that meets one of the exemptions contained in Section XVI.D.2. is not required to comply with the emission limitations, the compliance demonstration requirements and the related recordkeeping and reporting requirements contained in Sections XVI.D.4., XVI.D.5., XVI.D.7., and XVI.D.8., except for XVI.D.7.g, which requires a source that qualifies for an exemption under Section XVI.D.2., to maintain records demonstrating an exemption applies. All stationary combustion equipment is subject to some level of recordkeeping and may also be subject to combustion process adjustment requirements.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of Section XVI.D. as expeditiously as practicable but no later than 36 months after the equipment is no longer exempt. Therefore, if any stationary combustion equipment has to undertake a capital expenditure, such as installing a CEMS, in order to comply with Section XVI.D., then they have up to a maximum of three years to come into compliance. However, if no such capital expenditure or change in operational practice is required, then the stationary combustion equipment should comply sooner than three years (i.e. as expeditiously as practicable.) Additionally, once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations. This means that a source can fall into and out of having to comply with the emission limitation, monitoring, recordkeeping and reporting requirements of the rule if they satisfy the performance test requirements (i.e. the Division will not follow a "once in/always in" approach with respect to emission control requirements of exemptions.) Similarly, this 180-day period starts once the equipment is no longer exempt.

Monitoring, recordkeeping and reporting requirements

The Commission determined that affected stationary combustion equipment comply with certain monitoring, recordkeeping and reporting requirements by October 1, 2021. In order to provide clarity and regulatory certainty, many of the monitoring requirements adopted by the Commission incorporate by reference existing federal requirements and are consistent with rules in Moderate nonattainment areas in other states establishing RACT for these source categories.

The Commission is requiring CEMS or continuous emissions rate monitoring systems ("CERMS") for boilers with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, lightweight aggregate kilns with a maximum heat input design capacity equal to or greater than 50 MMBtu/hr, and glass melting. CERMS may require a stack gas flow rate monitor, where necessary, in order to measure volumetric flow rate and mass emissions. Where stack gas velocity is extremely low, as may be the case for a glass melting furnace, flow can be measured using a Division approved calculation methodology if flow cannot be accurately measured using traditional differential pressure or ultrasonic flow measuring devices. Moreover, where measuring emission rates in terms of emissions per unit of heat input (i.e. lb/MMBtu), EPA Method 19 calculations may be used using the appropriate F factor (i.e. the ratio of combustion gas volumes to heat inputs).

Further, it is the Commission's intent to allow electric utility boilers and stationary combustion turbines subject to the Acid Rain Program to use the quality assurance/quality control and data validation procedures in 40 CFR Part 75 for monitoring emissions to satisfy monitoring, recordkeeping and reporting requirements in this rule. Affected units that are subject to a NOx emission limitation in an NSPS and use CEMS or CERMS to monitor compliance with that limit can use those monitoring, recordkeeping and reporting requirements to demonstrate compliance with this rule. Similarly, owners or operators of stationary combustion turbines using performance testing to demonstrate compliance with NOx emission limitations of NSPS GG or KKKK may utilize those procedures for demonstrating compliance with the emission limitation in this rule. Where an initial performance test has already been conducted to determine compliance with NSPS GG or KKKK, it is not expected that another initial performance test must be performed for purposes of demonstrating compliance with Section XVI.D. Where an initial performance test has not been previously conducted, it must be completed by October 1, 2021 to demonstrate compliance.

For each initial or periodic test, sources should calculate the backup fuel's heat input for the calendar year prior to the year in which the performance test is required to determine if a test is required for each fuel or only for the primary fuel. Moreover, periodic performance tests must be conducted no more than 24 months apart.

With respect to the fuel flowmeter requirements, the Division reserves the right to audit quality assurance procedures with respect to manufacturer's instructions. The heat input measured and recorded by the fuel flowmeter is to be in the same unit of measurement as the applicable emission limitation. With respect to the quarterly or semi-annual reporting requirement, the Commission intended to only require that reports be submitted no less than semi-annually, but a source may submit quarterly reports in order to be consistent with existing reporting frequencies established in a permit and/or applicable NSPS or NESHAP.

With respect to the performance test reports, all performance test reports must compare average emissions determined by the performance test with the applicable emission limitation using the same number of significant figures as the emission limitation.

Incorporation by Reference in Sections XIX. and XVI.

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Sections XVI.D.5. and XIX.A. through D. by reference.

Additional Considerations

Colorado must revise its ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC and NOx in Colorado's ozone nonattainment area. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission adopted RACT requirements in Section XVI.D. for combustion equipment located at major sources of NOx in the DMNFR. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS Db, NSPS GG, NSPS KKKK, NSPS IIII, NSPS JJJJ, NSPS OOOO, NSPS OOOOa, and the compliance demonstration requirements in 40 CFR Parts 60 and 75 may apply to such stationary combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to specific existing stationary combustion equipment in the DMNFR.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in certain NSPS and MACT. Certain stationary combustion equipment with a lower heat input may trigger the combustion process adjustment work practice requirements of this rule.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7, Sections XVI. and XIX. establish categorical RACT for major sources of VOC and/or NOx, and thus are necessary to satisfy RACT SIP requirements for Moderate nonattainment areas and are specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The Revisions to Regulation Number 7, Sections XVI., and XIX. establish reasonable equity for major sources of VOC and/or NOx by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a 1-year clean data extension), EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal additional monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC and/or NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

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

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

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

R. November 15, 2018 (Sections I., II., VI., VIII., IX., X., XII., XIII., XVI., XVII., XIX., XX., and XXI.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

<u>Basis</u>

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable marginal attainment deadline and therefore reclassified the DMNFR area to moderate, effective June 3, 2016. Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 100 tons per year ("tpy") or more) and VOC source categories addressed by an EPA Control Techniques Guideline ("CTG").

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

In November 2016, the Commission determined that some major sources and CTG VOC source categories were adequately addressed under existing SIP requirements. The Commission also adopted new requirements for some major sources and CTG VOC source categories. In November 2017, the Commission adopted categorical RACT requirements for the oil and gas industry in response to EPA's Oil and Gas CTG. In July 2018, the Commission adopted categorical RACT requirements for combustion equipment at major sources that the Commission determined in 2016 were not addressed by SIP RACT requirements.

In this rulemaking, the Commission adopts SIP requirements that further support and complete Colorado's obligation as a moderate ozone nonattainment area to revise Colorado's SIP to include provisions that implement RACT for all major sources of VOC and/or NOx and for all CTG VOC source categories in the DMNFR ozone nonattainment area. Specifically, the Commission adopts categorical RACT requirements for major source breweries, wood furniture manufacturing, and addresses EPA concerns with the industrial cleaning solvent, metal furniture surface coating, and miscellaneous metal surface coating requirements. The Commission also revises specific rule or reference methods incorporated by reference to add applicable citation dates. Last, the Commission adopts specific revisions in a SIP clean-up effort.

Further, the Commission corrects typographical, grammatical, and formatting errors found throughout Regulation Number 7.

Major source RACT

Colorado has major sources of VOC and/or NOx in the DMNFR. Under marginal and moderate ozone nonattainment classifications, major sources are sources with the potential to emit greater than or equal to 100 tpy of NOx or VOC. Many of the major sources analyzed in 2016 were already subject to regulatory RACT requirements in Colorado's SIP, individual RACT requirements established in federally enforceable permits as a minor source RACT requirements, or an applicable federal New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutant ("NESHAP"). However, as a moderate nonattainment area, Colorado must include provisions in the SIP to implement RACT for Colorado's major sources. In November 2016, the Commission directed some major sources to submit RACT analyses to the Division, including two major source breweries. The Commission adopts in this November 2018, rulemaking categorical RACT requirements for major source brewing activities.

Major source breweries

The Commission adopts RACT requirements for owners and operators of breweries producing malt beverages and their brewery related operations at a major source VOC as of June 3, 2016, located in the DMNFR. In a moderate ozone nonattainment area, a major VOC source is one that emits or has the potential to emit greater than 100 tpy VOC. A brewery includes brewhouse, fermentation, aging, and/or packaging operations. Brewery related operations include operations that support the production of malt beverages such as wastewater management, container manufacturing, and ethanol distillation. The Commission established RACT for combustion equipment, including at breweries, in July 2018, in Regulation Number 7, Section XVI. The Commission now adopts a process loss limit and pollution prevention requirements for brewery packaging operations. These pollution prevention provisions include performance metrics to reduce product loss, operator training, and packaging equipment to reduce container breakage and product loss. The Commission also adopts wastewater management and treatment requirements for land application of wastewater. Lastly, the Commission adopts requirements for owners or operators to keep records of production, pollution prevention activities, and wastewater to demonstrate compliance with the operational requirements.

The largest VOC emissions sources inside a brewery are associated with packaging operations, including can, bottle, and other container fillers. Breweries can reduce VOC emissions by optimizing packaging operations. The process loss limitation is representative of packaging and filling optimization and, therefore, is an indicator, and potential driver, of the resulting VOC emission reductions. The process loss limitation does not include the railcar loading of beer concentrate that is shipped off-site for packaging. In this process, empty railcars are filled with beer concentrate held in beer concentrate receiving tanks after the aging process. The process loss from the automated loading of the beer concentrate from tanks into railcars is minimal and emissions from the filling of cans, bottles, kegs, or other containers are included with the emissions of the off-site packaging facility.

The process loss is calculated on calendar month and rolling 12-month bases across all packaging operations (i.e., filling lines), which aligns with existing product tracking programs. Process loss equates to the difference in the quantity of malt beverage metered at the filler and the quantity in containers as tracked for the Alcohol and Tobacco Tax and Trade Bureau (“TTB”). Operators determine the average calendar month process loss by comparing the total volumes metered at the fillers to the total volume counted by the TTB case counters. Owners or operators will then determine monthly average process loss percentage by dividing the difference in meter and case counter values by the total volume metered at the fillers. Utilizing an average process loss limit also allows for variations in individual line or brand product loss due to specialty brands or innovative containers. The brewing industry is seeing decreased sales of high-volume brands and increased consumer demand for small-volume unique or complex brands. This market change impacts process loss as the high-volume brands have low process loss values whereas specialty brands often result in higher process loss values due to brand recipe complexity, brand mix complexity, and production schedule complexity. The packaging of more types of brands and more complex brands result in higher process loss values because of differences in recipes that require more time for the filler to adjust to the appropriate fill level, more frequent product change-overs of the filling lines, and more unique packaging. The requirement to completely flush a filling line between brands also increases process loss values when the specialty brands are produced in lesser quantities than high-volume brands. Further, bottle filling lines often have different process loss values than can filling lines, therefore the change in container demand can impact the overall process loss. The average process loss limit of 6 percent on a calendar month and 4 percent on a 12-month rolling average leaves the necessary margin for variability and innovation, while still providing an indicator of RACT-level control of brewery packaging operations VOC emissions.

The Commission exempts from the process loss, pollution prevention, and recordkeeping requirements emissions units' subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 and emission units with total uncontrolled actual VOC emissions less than two tons per year. The first exemption was adopted to avoid subjecting sources to overlapping, duplicative, or contradictory RACT requirements. The second exemption was adopted for consistency with other major source RACT provisions and the use of Colorado's permitting thresholds for NOx and VOC to identify the emission points at major sources for which Colorado evaluated RACT.

The Commission also exempts equipment or activities related to research and development and newly installed, upgraded, or replaced packaging operations. Research and development activities include testing different recipes and packaging types before a product is distributed into commerce. The six-month startup exemption for newly installed, upgraded, or replaced packaging operations allows for the testing and adjustment of the new equipment to meet performance requirements. Examples of newly installed, upgraded, or replaced packaging operations include a new filling line or an upgraded or replaced man-to-machine-interface. Startup of newly installed, upgraded, or replaced packing operations does not include the startup or changeover of malt beverages or new recipes. Quality assurance teams follow a statistical process to verify that equipment is meeting quality standards prior to releasing salable product. These processes may include additional container testing, product sampling, or additional filler flushes while packaging operations are fine-tuned to meet key performance indicators. The volume of the product metered at the filler during the research and development and startup processes is excluded from the monthly process loss calculations. However, new, upgraded, or replaced packaging operations are not exempt from employees training requirements to ensure that employees understand the new packaging operations after startup.

Pollution prevention provisions also include the use and operation of packaging equipment to reduce container breakage and product loss. The Commission exempts from the automated filling equipment requirements packaging operations at pilot brewery operations. Automated filling equipment may be mechanical with a set fill quantity or electric with a flow meter and adjusting fill quantity. Both processes improve consistency, reduce spillage and product loss, and reduce the variation that may occur from human error.

The automated filling lines also include fill level detectors that will reject inadequately filled containers for recovery and recycling. A pilot brewery operation may serve the purposes of research and development but can also be utilized to produce very small quantities of product that is distributed into commerce. Pilot brewery operations can include different filling operations (e.g., bottles, kegs) but may use some manual filling related processes instead of automated processes. The use of manual processes is consistent with industry practices for operations of this small size, less than 50,000 barrels per year, and provides flexibility to account for production variations that may occur during research and development or small batch production.

Wood furniture manufacturing

In 2016, the Commission determined that only one source in the DMNFR exceeded the Wood Furniture CTG applicability threshold, and that source was a major source of VOC. Therefore, the Commission incorporated by reference requirements in 40 CFR Part 63, Subpart JJ (National Emission Standards for Wood Furniture Manufacturing Operations) into the SIP for wood furniture surface coating operations. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could streamline their RACT analysis by relating MACT controls to VOC RACT considerations. However, EPA has since expressed concerns that the NESHAP JJ volatile hazardous air pollutant ("VHAP") coating content limits may not adequately address coating VOC emissions. The Commission therefore removes the incorporation by reference of NESHAP JJ for wood furniture manufacturing operations in Section XIX. and is instead including the CTG recommended coating VOC content limits and work practices in Section IX.O.

The coating VOC content limits apply to sealers, topcoats, acid-cured alkyd amino vinyl sealers, or acid-cured alkyd amino conversion varnish topcoats. EPA's Wood Furniture CTG does not define acid-cured topcoats or sealers but does describe acid-catalyzed finishes as the most common catalyzed finishes. The Wood Furniture CTG further states that the film-forming resins in these finishes are usually a urea-formaldehyde or melamine-formaldehyde prepolymer mixed with an alkyd resin that serves as a plasticizer. Common catalysts contained in the acid-catalyzed finishes include sulfuric acid and p-toluenesulponic acid and film formation occurs through curing (polymerization) of the resins rather than drying.

SIP Clean-up

Industrial Cleaning Solvent

In 2016, the Commission adopted provisions in Regulation Number 7, Section X. to include RACT requirements related to the use of industrial cleaning solvents. The Commission adopted several exemptions recommended by EPA's Industrial Cleaning Solvents CTG as well as exemption for sources complying with cleaning solvent requirements in a federally enforceable NSPS, NESHAP, Best Available Control Technology requirement, or Lowest Achievable Emissions Rate requirement, which was similar to an EPA approved exemption in Colorado's Regional Haze SIP. EPA has since indicated concerns with approving this broad exemption due to a perceived lack of specificity. The Commission therefore removes the broad exemption in Section X.E.4.a.(i).

Metal furniture and miscellaneous metal surface coating

EPA published Metal Furniture CTGs in 1977 and 2007 and Miscellaneous Metal Parts and Products CTGs in 1978 and in 2008. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could conclude that sources already addressed by RACT determinations for a previous ozone NAAQS do not need to implement additional controls because a new RACT determination would result in the same or similar control technology as the initial RACT determination and any incremental emissions reduction from the application of a second round of controls would be small and the cost unreasonable.

Therefore, in 2016 the Commission relied on the RACT provisions relating to the 1977 and 1978 CTGs adopted into Regulation Number 7, Sections IX.H. and IX.L. in 1978 and 1980 to continue to establish RACT for metal furniture and miscellaneous metal coating operations. EPA has since indicated concerns with the existing provisions due to a lack of specified application technique. The Commission therefore revises Section IX. to specify the use of good air pollution control practices, including efficient application methods.

1990 and 1991 RACT Reports

In 1990, the Commission adopted one of several requirements in Regulation Number 7, specifically Sections I.B.2.f. and I.B.2.g., for existing sources to address EPA concerns with the design, implementation, and enforceability of Colorado's previously submitted and approved Ozone SIP. The provisions included one-time reporting requirements concerning source emissions and RACT for sources existing as of 1989. The provisions were not an ongoing reporting requirement potentially necessary for monitoring compliance with applicable emissions limits. EPA approved these provisions into Colorado's SIP in 1995, without discussion. Due to these one-time requirements having passed and Colorado's major stationary sources being subject to RACT requirements in Regulation Number 7, as adopted by the Commission through 2018, the Commission removed these historic provisions. Removal of these provisions does not remove or modify any control measures, therefore does not affect emissions nor interfere with attainment or reasonable further progress. Where information in the Sections I.B.2.f. and I.B.2.g. reports informed RACT requirements under Section II.C., sources remain subject to applicable RACT requirements and any emission reporting requirements as addressed by the emission statement rule last approved by EPA in 2015 (See 80 Fed. Reg. 50205 (August 19, 2015)).

Incorporation by Reference

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Sections II., VI., VIII., IX., X., XII., XIII., XVI., and XVII.

<u>Additional Considerations</u>

Colorado must revise its Ozone SIP to address the moderate ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC in Colorado's ozone nonattainment area. Colorado's major sources of VOC are subject to various and numerous NSPS or NESHAP, Regulation Number 7 requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC in the SIP. Specifically, the Commission adopted RACT requirements in Section XX. for brewing activities located at major sources of VOC in the DMNFR. The Commission also adopted RACT requirements from EPA's Wood Furniture CTG for wood furniture surface coating in Section IX. MACT JJ may apply to wood furniture surface coating operations.

(II) The federal rule discussed in (I) is primarily technology-based in that it largely prescribes the use of specific coating VHAP contents in order to comply. The federal rule provides flexibility by allowing subject facilities to select any coating meeting the specified VHAP content limits.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP. There is no timing issue that might justify changing this time frame.

(VI) The revisions to Regulation Number 7, Sections IX., X., and XX. establish categorical RACT for major sources of VOC and CTG VOC source categories, and thus are necessary to satisfy RACT SIP requirements for moderate nonattainment areas. The provisions are specific to emission points at sources of VOC, allowing for continued growth at Colorado's sources.

(VII) The Revisions to Regulation Number 7, Sections IX., X., and XX. establish reasonable equity for sources of VOC by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a one-year clean data extension) EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

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

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

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

S. December 19, 2019 (Sections I. through XX. and Appendices A through F – reorganized into Parts A through F)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) Sections 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

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 (Commission). This proposed rulemaking focuses on the Air Quality Control Commission directives in Section 25-7-109, CRS, SB19-181 directs the Commission to adopt regulations to "minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx)" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the Commission should consider including semi-annual leak detection and repair (LDAR) inspection requirements at all well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This rulemaking addressed many of the specific provisions for consideration, except continuous methane monitoring, but is only the first of many rulemakings to come in addressing SB 19-181.

Further, on August 15, 2019, the Environmental Protection Agency (EPA) proposed to reclassify the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). See 84 Fed. Reg. 41,674 (Aug. 15, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy and the DMNFR's attainment date becomes July 20, 2021. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Therefore, as a first step to addressing the new statutory directives, and ensuring progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to minimize emissions from the oil and gas sector and to include reasonably available control technology (RACT) requirements for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy. The oil and gas industry is a significant source of VOC, NOx, ethane, and methane emissions, and the Commission expects the industry's growth to continue in the foreseeable future. Improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs, ethane, and methane in a cost-effective manner. These technologies and practices include, without limitation, frequent LDAR inspections, reducing emissions from pneumatic controllers, reducing emissions from the transmission segment, storage tank measurement systems, and vapor collection and return equipment.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO (and NSPS OOOOa) are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both State Implementation Plan (SIP) requirements that apply in the DMNFR and state-only requirements that apply state-wide. In addition, evidence in the rulemaking record supports the conclusion that the rules can be implemented effectively. Accordingly, the Commission concludes that the rules are technologically feasible and cost-effective.

Statutory Authority

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

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas operations, including well production facilities and natural gas compressor stations. The Commission expands the inspection and enhanced response program for pneumatic controllers it adopted in 2017 for pneumatic controllers in the DMNFR to a state-wide applicability. The Commission adopts a new, innovative performance based program to reduce emissions from the downstream transmission segment.

The Commission is replacing the system-wide condensate storage tank control strategy in the SIP with a more straight-forward storage tank control threshold. The Commission is also seeking to reduce emissions from storage tank measurement and sampling and loadout activities, and to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission is expanding the requirement to employ best management practices to minimize emissions at oil and gas wells during well plugging activities. The Commission is also establishing an annual emissions inventory report that oil and gas operators will submit to the Division, which will ensure accountability and assist the Commission in understanding the emissions of methane, ethane, VOC, CO, and NOx associated with different activities and equipment in oil and gas operations. The Commission believes that this combination of revisions is appropriate as a first step in minimizing emissions from oil and gas operations and continuing to make progress towards attainment of the ozone NAAQS.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources (> 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, including categorical RACT requirements, and requiring the submission of RACT analyses.

The Commission is also updating requirements for gasoline transport trucks, bulk terminals, and service stations to align with current federal requirements in a SIP clean-up effort.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Reorganization

Over the years, Regulation Number 7 has grown. In an effort to facilitate readability, and to better allow the regulated community to identify and understand the provisions governing their activities, the Division is proposing a full reorganization of Regulation Number 7 into parts. A table identifying the new section(s) along with the prior section/location is shown. This Statement of Basis and Purpose will refer to the reorganized section numbers in the discussion of revisions and new provisions.

Reorganized Regulation Number 7 Section	Regulation Number 7 Section (as of 11/15/2018)
Part A	
Part A, Section I.	I. Applicability
Part A, Section II.	II. General Provisions
Part A, Appendix A	Appendix A. Colorado Ozone Nonattainment or Attainment Maintenance Areas

Part B	
Part B, Section I.	III. General Requirements for Storage and Transfer of Volatile Organic Compounds
Part B, Section II.	IV. Storage of Highly Volatile Organic Compounds
Part B, Section III.	V. Disposal of Volatile Organic Compounds
Part B, Section IV.	VI. Storage and Transfer of Petroleum Liquids
Part B, Section V.	VII. Crude Oil
Part B, Section VI.	VIII. Petroleum Processing and Refining
Part B, Section VII.	XV. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities
Part B, Appendix B	Appendix B. Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks
Part B, Appendix C	Appendix C. Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants (Vapor Balance System)
	Appendix E – deleted, paragraphs B and E moved into section, and references replaced with EPA Method 27

Part C	
Part C, Section I.	IX. Surface Coating Operations
Part C, Section II.	X. Use of Cleaning Solvents

Part C, Section III.	XI. Use of Cutback Asphalt
Part C, Section IV.	XIII. Graphic Arts and Printing
Part C, Section V.	XIV. Pharmaceutical Synthesis
Part C, Appendix D	Appendix D. Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers
Part C, Appendix E	Appendix F. Emission Limit Conversion Procedure

Part D	
Part D, Section I.	XII. Volatile Organic Compound Emissions from Oil and Gas Operations
Part D, Section II.	XVII. (State Only, except Section XVII.E.3.a., which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines
Part D, Section III.	XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations
Part D, Section IV. (State Only) Control of emissions from the transmission and storage segment	NEW
Part D, Section V. (State Only) Oil and Natural Gas Operations Emissions Inventory	NEW

Part E	
Part E, Section I.	XVI.A.-C. (natural gas fired reciprocating internal combustion engines in the 8-hour ozone control area) and XVII.E. (new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines)
Part E, Section II.	XVI.D. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area
Part E, Section III.	XIX. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-Hour Ozone Control Area
Part E, Section IV.	XX. Control of Emissions from Breweries in the 8-Hour Ozone Control Area

Part F	
	XXI. Statements of Basis, Specific Statutory Authority and Purpose

State Implementation Plan Revisions (Part D, Section I. (formerly Section XII.))

The Commission adopted several revisions to the SIP provisions that were previously found in Section XII. While not strictly necessary to comply with a particular CAA requirement pertaining to ozone, the revisions implement the mandate of SB 19-181, strengthen Colorado's Ozone SIP, and will achieve further reductions in ozone precursors and other hydrocarbons.

Applicability (Section I.A)

The Commission revised the applicability language of Part D, Section I. to clarify that all oil and gas operations at and upstream of the natural gas processing plant are subject to the provisions of Section I., as more specifically set forth in Sections I.A through L. The Commission also revised the applicability to ensure that storage tanks containing hydrocarbon liquids (*e.g.*, condensate, crude oil) and produced water are subject to the provisions of Section I., which previously applied only to condensate storage tanks.

Further, under previous provisions, owners and operators of condensate storage tanks for which the APENs reflecting emissions from all operations were 30 tpy VOC or less were exempted from Section I. Given the challenges with attaining the ozone NAAQS, the number of tanks that were exempt under this provision, and the need for further reducing emissions from those tanks, the Commission removed this exemption.

However, the Commission retained the exemption from the system-wide control strategy in Section I.I. (formerly Section XII.I.) for owners or operators of natural gas compressor stations that do not also own or operator exploration and production facilities and the exemption in Section I.G. (formerly XII.G.) for owners or operators of natural gas processing plants. Owners or operators of these facilities must continue to control condensate storage tanks as specified in Sections I.I. and I.G. By retaining these exemptions, the Commission does not intend to exempt these facilities from any applicable requirements in Part D, Section II.

Storage Tank Controls (Section I.D)

In 2004, the Commission adopted the initial system-wide control strategy, which required operators to reduce emissions from their system of condensate tanks. The “system” was comprised of condensate tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy, and allowed operators to decide which tanks to control so long as emissions from the “system” were reduced by specified percentages. The system-wide control strategy involved complicated and often times confusing recordkeeping and reporting. Further, the system-wide control strategy had the unintended impact of disincentivizing operators to build new facilities without storage tanks (a real emissions benefit), because operators could not take credit for the production at tankless facilities in their “system.” As a result, the Commission replaced the system-wide control strategy with a straightforward control threshold. Operators in the 8-hour Ozone Control Area will have until May 1, 2020, (prior to summer ozone season 2020) to install controls on storage tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy. Only the requirements for storage tanks with uncontrolled actual VOC emissions equal to or greater than 4 tpy are included in the SIP, while the requirements for the storage tanks between 2 and 4 tpy will remain state-only. This provision expands the control requirements to crude oil and produced water tanks, and will result in several hundred more tanks being controlled. The Commission has reviewed the evidence and has determined that the 4 tpy SIP threshold and implementation timetable is cost-effective, technically feasible, and will ensure no backsliding as provided for in the Clean Air Act, Section 110(l). In Sections I.D.3.b.(v) and I.D.3.b.(vi)., the Commission has required that storage tanks below the 2 tpy threshold that increase emissions above the threshold must be in compliance with 60 days of the first date of the month after which the threshold was exceeded. As a result, if a storage tank exceeds the 2 tpy threshold in September 2020, based on a rolling twelve-month total (*i.e.*, October 2019-September 2020), the tank must have controls installed and operating within 60 days of October 1, 2020. These provisions will not only minimize emissions from storage tanks but will ensure clarity in the applicability of control requirements and will assist Colorado in making additional progress towards attainment of the ozone NAAQS.

The Commission has also determined that storage tanks that cannot install controls by the applicable compliance date may shut-in all wells producing to the applicable storage tanks, so long as production from any well producing into the storage tank is not resumed until controls are installed. It is the Commission's intent that this allowance not apply unless the operator shuts in all wells feeding in to the storage tank/battery requiring controls. This will avoid the need for operators to install control equipment when wells are shut-in and where the operator may determine not to return those wells to production. Further, the Commission intends that the Division will work with operators in the DMNFR to allow for appropriate time to conduct design analyses to comply with Sections I.C.1.b. and II.C.2.a., as long as operators install required controls by May 1, 2020, and are pursuing compliance with reasonable diligence.

The Commission has also included in the SIP in Sections I.D.2.a. and II.C.1.b.(ii) the existing requirements (formerly Sections XII.D.1. and XVII.C.1.c.) that operators of newly constructed tanks employ controls during the first 90 days after the date of first production (this provision was previously designated state-only). However, these revisions to Regulation Number 7, in conjunction with revisions to Regulation Number 3, use the term "commencement of operation" instead of "date of first production." This SIP revision is not part of Colorado's ozone attainment requirements but is directed at making this requirement enforceable by the EPA and members of the public under the CAA. While the Commission does not believe inclusion of this provision in the SIP was required for compliance with Colorado's permitting program in Regulation Number 3 with CAA requirements, including ozone nonattainment area requirements, pursuant to Section 25-7-105.1(1), CRS, including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purpose of permitting.

Storage Tank Monitoring (Section I.E)

The Commission revised Section I.E. to apply the monitoring requirements to all storage tanks controlled pursuant to Section I.D., which will ensure monitoring not only of condensate tanks, but also of crude oil and produced water tanks on a weekly basis. The required inspections have also been updated to include common-sense elements that can have a real impact on performance of well production facility equipment and can reduce emissions. For example, checking that burner trays are not visibly clogged can improve the performance of air pollution control equipment. The Commission does not intend that operators should shut-in the combustor for the sole purpose of performing this inspection to observe the burner tray, and need only inspect those portions of burner trays that are visible without shutting in. The Commission also adopted into Section I.E. requirements that previously existed in Section II. (formerly Section XVII.) to check that pressure relief valves are properly seated and that vent lines are closed. Similarly, to the inspection in Section II.C.1.d.(i), operators are not expected to disassemble or otherwise manipulate the pressure relief valve to complete the inspection, unless the visual observation of the valve reveals it is unseated and corrective action needs to be taken. Further, the Commission does not expect operators to climb on top of a tank to observe the pressure relief valve. However, operators are expected to use an available catwalk or similar permanent access to ensure the best opportunity for inspection, except when a catwalk is not accessible due to a safety hazard.

The Commission has removed references to recordkeeping from Section I.E. and has attempted to condense all recordkeeping requirements in Section I.F. For example, Section I.E.2.c.(iv) no longer provides that operators must "check for and document" the inspection; instead, Section I.E.2.c. requires operators to "check", and the requirement to "document" the inspection is found in Section I.F.2.c.

Recordkeeping and Reporting (Section I.F)

As a result of replacing the system-wide control strategy with the fixed control threshold, the Commission revised the recordkeeping and reporting requirements for demonstrating compliance with Section I.D. Operators subject to the system-wide control strategy will still be required to submit an annual report for calendar year 2019 by the same deadline of April 30, 2020, and are given until August 31, 2020, to submit the report for the time period in 2020 during which the system-wide control strategy remains effective (*i.e.* January 1 – April 30, 2020). In Sections I.F.2. and I.F.3., the Commission has created a new recordkeeping and reporting scheme for the tanks subject to the new control threshold provisions. The Commission has largely maintained the same recordkeeping and reporting requirements for the monitoring provisions in Section I.E. However, the Commission streamlined the new storage tank recordkeeping and reporting requirements, which are included in the SIP for storage tanks at or above the 4 tpy threshold, but are included on a state-only basis for the storage tanks between 2 and 4 tpy.

Miscellaneous

The Commission adopted revisions to definitions (Section I.B.) and the general provisions (Section I.C.). A new definition for “commencement of operation” was added for consistency with Regulation Number 3 and for clarity as to the applicability of other control requirements (previous versions of Regulation Number 7 were tied to the “date of first production,” which was not implemented consistently amongst operators). The Commission adopted the term “date of first production” in 2014 with the intent that it coincides with the date reported to the Colorado Oil and Gas Conservation Commission (COGCC) on COGCC Form 5A. Through implementation of the 2014 revisions, differences between the Commission’s and the COGCC’s use of the term were realized. Therefore, the Commission has replaced “date of first production” with the more clearly defined “commencement of operation” term.

The Commission also adopted new definitions for “hydrocarbon liquid,” “produced water,” “storage tank,” and “storage vessel” to ensure consistency with the state-only program in Part D, Section II. The definition of “storage tank” referred to the federal definition of “storage vessel” and, therefore, captured crude oil and produced water tanks, in addition to condensate tanks. The federal definition has now been included as a standalone definition of “storage vessel.”

The Commission also revised Section I.C.1.b. to reflect that Section I. now applies to oil and gas operations collecting, storing, processing, and handling hydrocarbon liquids and produced water, not just condensate. The Commission replaced the term “leakage” with the term “emission” in order to be consistent with the Common Provisions definition of “emission.” The Commission does not intend this latter revision to reflect a change in the meaning or applicability of Section I.C.1.b. (or Section II.B.1.a., where this revision is also made), but only to improve clarity.

The Commission revised Section I.C.2., which specifies how operators must calculate emissions and emission reductions for purposes of demonstrating compliance with the control requirements. These revisions expand the current provisions to storage tanks storing hydrocarbon liquids other than condensate and to storage tanks storing produced water. For crude oil tanks and produced water tanks, operators will need to refer to default emission factors as established and updated by the Division. *See, e.g.* PS Memo 14-03, *Oil & Gas Industry Crude Oil, Condensate and Produced Water Atmospheric Condensate Storage Tanks, Regulatory Definitions and Permitting Guidance for General Permit GP08*.

The Commission has not substantively revised the LDAR SIP provisions of Section I.L. but clarified that applicability is based on emissions on a rolling twelve-month basis, not a calendar year basis. Such was the Commission’s intention in adopting the program in 2017.

The Commission has also determined to incorporate Section II.F. (formerly Section XVII.G.) into the SIP. This provision requires control of emissions coming off a separator after a well is newly constructed, hydraulically fractured, or recompleted. These emissions must be routed to a gas gathering line or controlled by air pollution control equipment. This SIP revision is not part of Colorado's ozone attainment compliance requirements, but is directed at clarifying that this requirement is enforceable by the EPA and members of the public under the CAA. Including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purposes of permitting. *See* Section 25-7-105.1(1), CRS.

<u>State-wide, State-Only Revisions (Part D, Section II. (formerly Section XVII.))</u>

In Part D, Section II., the Commission adopted several revisions to begin its implementation of SB 19-181. These revisions further support existing control requirements and also seek reductions from previously unregulated emissions activities (*e.g.*, gauging and loadout).

Storage Tank Controls, Monitoring, Recordkeeping, and Reporting (Sections II.C.1.c., II.C.1.d., II.C.2.b. and II.C.3.)

Since 2011, Colorado has made significant progress in reducing emissions from storage tanks. However, storage tanks remain the largest source not only of oil and gas VOC emissions, but of all anthropogenic VOC emission sources in the state (per the 2017 nonattainment area emissions inventory in the Moderate area ozone nonattainment SIP). The Commission has determined that it is cost effective and technically feasible to lower the control threshold from 6 tpy VOC (as established in 2014) to 2 tpy VOC. However, the Commission does not want to facilitate or encourage the use of supplemental fuel to operate control equipment, and understands that this can occasionally be an issue on the West Slope, in particular, where the facilities have lower pressure. The Commission has therefore adopted a provision that allows operators to seek from the Division an exception to controlling tanks between 2 and 6 tpy VOC under these circumstances. Exceptions should be sought prior to compliance deadlines, and will be effective upon submittal unless and until the Division determines an exception is not appropriate. Storage tanks constructed on or after March 1, 2020, must have controls upon commencement of operation, ensuring reductions during the 2020 summer ozone season. Storage tanks outside the nonattainment area constructed prior to March 1, 2020, must be in compliance by May 1, 2021. The Commission determined it was appropriate to give tanks outside the nonattainment area between 2 and 6 tpy VOC extra time to install controls. The Commission does not intend to give extra time to storage tanks with air pollution control equipment already installed, even where controls are not currently required by Regulation Number 7 (e.g., where an operator has submitted an APEN claiming controls).

The Commission revised the approved instrument monitoring method (AIMM) schedule for inspections of controlled storage tanks to align with the Commission's revision of the LDAR inspection frequencies in response to SB 19-181, discussed further. The Commission adopted a semi-annual frequency for storage tanks with emissions greater than or equal to 2 tpy and less than or equal to 12 tpy. For storage tanks with emissions greater than or equal to 6 tpy and less than or equal to 12 tpy, this is an increase in inspection frequency from annual to semi-annual. Where the Commission specifies that semi-annual monitoring must "begin" in a certain year, the Commission intends that there be at least two AIMM inspections during that year. The Commission also removed the phase-in schedule for storage tanks inspections (within 90 days of January 1, 2016 for storage tanks > 6 and within 30 days for storage tanks > 50 tpy) as those schedules have passed. The Commission updated the recordkeeping requirements for AIMM inspections to be consistent with the LDAR recordkeeping in Section II.E. Records of AIMM inspections under Sections II.C. and II.E. may be maintained together, and need not be kept separately.

The Commission has also strengthened monitoring requirements for storage tanks and associated equipment. In Section II.C.1.d., the Commission has determined that it is cost effective and feasible, while already on-site for visual inspection, to check the dump valve on the separator to ensure that it is not stuck open or visibly clogged. The Commission does not intend that operators will need to manipulate equipment or stay on-site for the purpose of observing actuation of the dump valve for purposes of this inspection requirement. The Commission has also determined that excess liquids in the vapor lines can cause a multitude of problems, including over pressurization of the tanks or smoking flares. Therefore, the Commission is directing operators to check liquid knockout vessels, when present, unless the vessel is set up to drain automatically, and to drain liquids if above the low-level indication point. If the knockout vessel is not equipped with a liquid level indicator, operators can comply with this requirement by draining the knockout vessel during the inspection. Further, for underground lines and above-ground lines where no knockout vessel is used, operators should establish a procedure by which they evaluate for the presence of liquids in the vapor lines, and drain as necessary. Appropriate operating and maintenance program documents should set forth this procedure so as to provide clarity on how an operator determines draining is necessary. These actions can be taken while the operator is already on-site for the inspections previously required, are consistent with actions the Commission generally understands operators are already taking in the field and therefore, the Commission does not expect these actions to create additional burden.

The LDAR program in Section II.E. (formerly Section XVII.F.) has required remonitoring following repair of a leak (as has Section I.L.). However, Section II.C. did not include an explicit remonitoring requirement following actions taken to address venting from storage tanks. Operators must now confirm that actions taken to address venting were effective through remonitoring. This confirmation must be made within 24 hours of the action taken to address the venting. This requirement does not reflect a timeframe in which the operator may address the venting without incurring liability for the violation. There is currently no regulatory period in which venting will not be considered a violation of Section II.C.2.a., unless the venting is reasonably necessary for one of the reasons expressly contemplated by Section II.C.2.a. Only where the initial emissions observation was observed through AIMM does the success of the response action need to be verified through AIMM. However, the Commission believes that if the venting was found with an IR camera and was addressed while the IR camera operator was on-site, then there is little to no burden to use the IR camera to confirm, for example, an effective seating of the thief hatch upon closure. In Section II.C.3.f., the Commission has established supplemental recordkeeping requirements when venting is observed and addressed.

In Section II.C.3.d., the Commission has strengthened recordkeeping requirements of inspections under Section II.C.1. These recordkeeping requirements are consistent with the recordkeeping required in Section I.F. (formerly Section XII.F.). The Commission has maintained the exemption from recordkeeping under Section II.C.3.b., for instances where venting is reasonably necessary for maintenance, gauging (unless a storage tank measurement system is required under and the operator complies with Section II.C.4.), or safety of personnel and equipment. However, the Commission expects that the emissions associated with these venting events will be reported in the annual emissions inventory.

Storage Tank Measurement Systems (Section II.C.4.)

Historically, operators have needed – for operational purposes – to open the thief hatch on storage tanks in order to sample and measure the level of the liquid to be sold (i.e., to determine quality and quantity). Technology has advanced over the past few years, including, without limitation, the use of Lease Automatic Custody Transfer (LACT) units, automated tank gauges, and the development of API 18.2 (Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods), which allow for the sampling and measurement of liquids without opening the thief hatch. It is the Commission’s intention that owners and operators of facilities and tanks constructed after the deadlines in new Section II.C.4. must measure the level of the liquid (e.g., use tank level sensors) and sample the liquids (e.g., check for temperature, BS&W, and other indicia of merchantability) without opening the thief hatch. These storage tank measurement systems can be employed at facilities with and without automation.

Further, a significant number of operators have already deployed such systems at large and small facilities in the DJ Basin, in some cases voluntarily and in some cases as required pursuant to a Consent Decree or Compliance Order on Consent. The Commission notes that a storage tank management system may be different for tanks where liquids are both sampled and measured than for tanks where liquids are not sampled. For example, Commission understands that some produced water tanks are not sampled for quality, and therefore do not need to have equipment to allow for the sampling of the liquids without opening of the thief hatch.

Therefore, the Commission adopted a requirement to employ storage tank measurement systems to determine the quantity of the liquid at well production facilities, natural gas compressor stations, and natural gas processing plants constructed on or after May 1, 2020. Any such facilities that are constructed after January 1, 2021, must have storage tank management systems in place that determine both the quality and the quantity of the liquid. This requirement also applies to storage tanks at existing well production facilities, natural gas compressor stations, and natural gas processing plants that are modified by adding storage tanks. When operators add new storage vessels to existing facilities (e.g., to add capacity because production or throughput is expected to increase), they must outfit the new storage vessels and retrofit the existing vessels in the same battery with a storage tank management system. However, the ability to retrofit an existing battery may not exist, and is therefore not required, where a single storage tank is replaced due to maintenance concerns or where a tank is installed to provide extra head space in the vapor control system, but no production increase is associated with the installation.

The Commission has adopted minimal recordkeeping provisions for this requirement, including a description of the storage tank measurement system and records of the annual training program. The description must be sufficiently detailed to enable the Division to determine whether the operator is in compliance (e.g., sampling the liquids without opening the thief hatch). If an operator relies on a third party (e.g., hauler) to perform the gauging activities, those operators will need to work with the haulers to facilitate the training that will familiarize haulers with this new requirement.

The Commission has also adopted a requirement to allow for periodic calibration and testing of the storage tank measurement system. The Commission recognizes that while the Bureau of Land Management expressly allows for automatic tank gauging (*see e.g.* 42 C.F.R. Section 3174.3(33), incorporating by reference API 18.2), it can be necessary to test and calibrate the automatic tank gauging system. *See* 42 C.F.R. Section 3174.6(b)(5)(ii)(B). It is not the Commission's intent to adopt requirements at odds with the Bureau of Land Management. Further, some manufacturers may recommend inspection, testing, or calibration more frequently than specified by the Commission; the Commission intends to allow for those maintenance procedures, as reasonably necessary (i.e., the exception should not render ineffective the Commission's intent that thief hatches remain closed during the sampling and measurement process). Operators that perform maintenance procedures more frequently than semi-annually need to document the manufacturer's recommendation for the increased frequency and provide those materials to the Division upon request.

Hydrocarbon Liquids Loadout (Section II.C.5)

In Section II.C.5., the Commission has adopted new requirements to control or avoid emissions associated with the unloading of hydrocarbon liquids into transport vehicles (e.g., trucks). These requirements do not apply to produced water loadout. The Commission has determined to prohibit the venting of hydrocarbons during loadout activities, because the venting is not reasonably necessary within the meaning of Section II.C.2.a.; however, the Commission notes that some thief hatches may be "open" during loadout but are not emitting and are instead operating only as vacuum relief for the storage tank. An "open" pressure relief device that does not emit, but instead creates a vacuum, would not be a violation of the prohibition on venting during loadout, though the burden will remain on operators to demonstrate that any open pressure relief devices are not venting.

These requirements will apply to well production facilities, natural gas compressor stations, and natural gas processing plants constructed before and after May 1, 2020, with annual hydrocarbon liquid loadout throughput equal to or greater than 5,000 barrels per year, on a 12-month rolling basis. Throughput is based on the throughput of liquids loaded out to transport vehicles and does not include liquids loaded out to pipeline. Facilities constructed after May 1, 2020, must control emissions from loadout upon commencement of operation if they anticipate having a loadout throughput over 5,000 barrels per year. Facilities that are modified (e.g., new well drilled, well re-fracked or recompleted) that expect to have throughput over 5,000 barrels per year must also control loadout operations upon commencement of operation following the modification. Facilities that increase throughput such that loadout throughput reaches 5,000 barrels must control the emissions from loadout upon reaching 5,000 barrels. The Commission does not intend that operators may loadout more than 4,999 barrels of hydrocarbon liquids without controls. Thus, if an operator currently loads out to pipeline, and is not subject to this requirement, but the pipeline becomes unavailable (e.g., due to maintenance, whether scheduled or unscheduled) and the operator has 6,000 barrels stored in tanks, the operator must control the emissions from the loadout to transport vehicles or wait to loadout to transport vehicles until it can arrange for controls.

The Commission recognizes that compliance may be more cost effective at newly constructed facilities for several reasons. Operators may account for the vapors associated with loadout in the initial evaluation of air pollution control equipment required. Operators may also design the facility to make compliance easier, with both these requirements and Section II.C.4. However, the Commission has determined that it is also cost-effective and technically feasible to retrofit existing facilities to control loadout emissions. Operators using air pollution control equipment to control loadout emissions must also comply with other Regulation Number 7 requirements applicable to air pollution control equipment (e.g., inspections, recordkeeping). Further, if operators employ vapor collection and return systems, operators should include this vapor source in the engineering evaluation of their storage tanks and vapor control systems to avoid over-pressurizing the tanks.

The Commission has also established additional requirements to ensure the effective control of loadout emissions, including many requirements that the Division has previously established as permit RACT (under Regulation Number 3 and not as categorical RACT used for ozone SIP purposes) in loadout permits. The Commission determined that observation of and/or training and signage related to the loadout process by operators will help ensure that new staff and third parties are effectively implementing these requirements. The Commission directed the Division to develop a template and/or guidance regarding expectations for signage. However, if tanks are loaded out less frequently than monthly, the observation needs to take place during loadout when it does occur, unless observation is not feasible. If observation is not feasible (e.g., the operator did not receive notice of the loadout, which occurred during the middle of the night when no operator personnel was on site), the operator must inspect the facility within 24 hours to ensure that loadout equipment was properly stored and that thief hatches were closed. The Commission encourages the Division to work with operators to better understand when observation is, or is not, feasible.

Leak Detection and Repair (Section II.E)

In SB 19-181, the Legislature directed the Commission to minimize emissions from the oil and gas sector, including the gathering and boosting segment (i.e., compression). In conjunction with this directive, SB 19-181 further instructed the Commission to consider semi-annual monitoring for leaks at well production facilities. Therefore, the Commission has revised the LDAR program of Section II.E. (formerly Section XVII.F.) to increase the frequency of approved instrument monitoring method (AIMM) inspections to semi-annual at compressor stations with emissions between 0 and 12 tpy VOC and at well production facilities with emissions between 2 and 12 tpy VOC. Phase-in of these new inspections begins in 2020, and the Commission expects that operators will conduct the first semi-annual inspection prior to the start of the summer ozone season (i.e., May 1, 2020). Current requirements in place for larger facilities to inspect on a more frequent basis remain unchanged.

The Commission adopted a proposal to require enhanced leak detection and repair requirements for facilities within 1,000 feet of an occupied structure. The commission also directed the Division to work on a proposal that would speed up repair times in these areas and bring forward for the Commission's consideration in a future rulemaking hearing as soon as possible.

There are no other substantive changes to the existing LDAR program.

Emissions Associated with Well Maintenance, Unloading, and Plugging Activities (Section II.G)

In 2014, the Commission adopted a requirement that operators use best management practices (BMPs) to minimize hydrocarbon emissions and the need for well venting associated with well liquids unloading and well maintenance. The Commission is replacing the term "venting" with "emissions" or "emitting" to ensure consistency with the Common Provisions definition of "emission" and to avoid any confusion with the new definition of "venting" that was added to Section II.C.2.a.(i) (formerly Section XVII.C.2.a.(i)) in 2017, though no change in meaning or applicability is intended. The Commission has determined that BMPs should also be employed to reduce emissions from the well associated with well plugging activities. These activities have been increasing in frequency in the DMNFR in recent years, and the Commission finds that BMPs are a cost-effective and flexible proactive strategy to address this emerging emissions source. BMPs include both practices that reduce the need for well liquids unloading or well maintenance activities and practices that reduce or control emissions resulting from the well maintenance, well liquids unloading, and well plugging activities.

The Commission has also clarified and strengthened the recordkeeping and reporting requirements associated with the well emissions and BMPs. The inventories that will be required to demonstrate attainment with the ozone NAAQS in future SIPs necessitate detailed information on the emissions associated with these activities. Further, understanding BMPs employed to reduce or eliminate these emissions will assist the Commission in developing both voluntary and regulatory strategies to make further progress towards attainment. In an effort to minimize duplication with the new emissions inventory in Section V., the Commission intends that all information associated with activities covered by this Section II.G. will be reported on a separate form and not as part of the Section V. inventory. While recordkeeping is to begin in July 2020, the Commission understands that current methods of reporting emissions from these activities may need to be updated or improved in the future, and the Commission directs the Division to work with stakeholders to update emission factors and/or calculation methods as necessary.

Miscellaneous

Section II.C.2.a. prohibits the venting of hydrocarbons, unless reasonably required for maintenance, gauging, or safety. The Commission now clarifies that venting during gauging is expressly prohibited under this requirement where a storage tank measurement system is required under Section II.C.4. If Section II.C.4. allows for the opening of the thief hatch, that activity will not be considered venting within the meaning of Section II.C.2.a.

The Commission has revised Section II.C.2.b.(i), to reflect its intention in adopting the STEM provisions in 2014. The Commission intended in 2014, and specifically noted in the Statement of Basis and Purpose at that time, that STEM plans should include an analysis of the engineering design of the storage tank and associated air pollution control equipment (i.e., the vapor control system) to ensure that storage tanks are not over pressurized, causing excess emissions. The Commission believes that operators now largely understand and comply with this requirement, but has clarified the language in the rule itself principally to aid operators that may be new to the control program as a result of the new, lower control threshold. The Commission notes that this requirement does not require that operators maintain a site-specific design analysis for each facility. Worst-case design analyses or like-kind design analyses for similarly configured facilities may be utilized; however, the burden remains with the operator to show that the design analysis provided for the facility demonstrates adequacy of design.

Further, the Commission acknowledges that closed-loop tank pressure control systems designed to maintain tank pressures below a specified point can be, if designed and operated property, indicative of adequate design. The Commission also acknowledges that design analyses do not need to be maintained within the STEM plan itself, so long as the STEM plan contains a description of the design analysis method employed and specifies the name and location of the design analysis for each facility covered by that STEM plan.

<u>Pneumatic Controllers (Part D, Section III.)</u>

SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.

The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.

The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings.

<u>Downstream transmission (Part D, Section IV.)</u>

SB 19-181 also directed the Commission to consider adopting a requirement that owners and operators of oil and gas transmission pipeline and compressor stations inspect and maintain all equipment and pipelines. The Commission’s Regulation Number 7 has not historically regulated the transmission and storage segment, which includes pipeline, compressor stations, and other equipment transporting and storing natural gas downstream of the natural gas processing plant and prior to the distribution segment. Transmission pipelines, however, have been subject to federal and state pipeline safety regulations.

To address the new directive to minimize emissions from the transmission segment, the Commission adopted an innovative program that directs the setting of a methane intensity target and associated programmatic framework. This approach is the second recommendation from the SHER team, and again comes before the January 2020 deadline established by the Commission in November 2017. SHER team stakeholders involved in developing this program include trade associations, transmission segment operators, environmental and citizen groups, local governments, and the Division. The Division will approve a steering committee charter that will detail the purpose, responsibilities, and deliverables of the steering committee. The steering committee will develop an emissions protocol detailing the calculation and reporting of VOC, CO, NOx, ethane, and methane emissions and any associated program guidance documents or templates by September 30, 2020, determine a segment methane emissions intensity target by October 1, 2023, and certify initial target compliance based on the 2024 data. Each owner or operator in the segment will develop a company-specific best management practice (BMP) plan, the elements of which are enforceable by the Division. A goal of this program is continual improvement over time through review of BMPs, assessment of reported emissions and emissions intensity, and analysis of other data and best practices. In furtherance of this goal, the steering committee will periodically reassess the emissions intensity target and may consider, among other factors, the potential to reduce emissions from events beyond the control of the owner or operator.

The Division will provide an update on the development of the program to the Commission in 2021 as well as periodic updates regarding the progress of the program. The program will include a reporting element to demonstrate compliance and continual improvement. The steering committee will develop the criteria by which the industry participants will select a third-party contractor to collect and aggregate the company-wide reports into the segment-wide report prior to the first report due date of September 30, 2022. The third-party contractor, with involvement from the transmission segment owners or operators, may also provide VOC, NOx, and CO emissions data from the annual company-wide reports to the Division related to ozone modeling as needed and requested. Each year after the segment-wide emissions intensity target is established, the steering committee will submit a compliance certification to the Division that the transmission segment achieved the target. If such certification cannot be made, the steering committee will develop a plan for the segment to achieve compliance with the target. This plan, if needed, may include amendments to the program guidance documents, prescriptive control requirements, or other strategies to reduce methane emissions such that the transmission segment achieves the segment-wide emissions intensity target.

The inventory protocol may be based on existing EPA estimation and reporting mechanisms, specifically the EPA's Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI). The emission estimation mechanisms may be updated as emission factors or calculation methods are revised. The inventory protocol will include the method(s) by which the transmission segment owners or operators will quantify and report emissions. The findings of the Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems (MAC) report (May 2016), among other data sources, may be used to develop the segment-specific methane emission reduction goals that, when combined, will achieve the transmission segment's emission intensity target in a cost-effective manner.

Annual inventory (Part D, Section V)

The Commission established an annual emissions reporting requirement to regularly update the Division's emissions inventory for equipment and activities in oil and gas operations. This inventory is intended to assist Colorado in ozone planning and the creation of emission inventories for use in ozone attainment modeling, as well as to comply with the directives in SB 19-181 to minimize emissions from the oil and gas sector. This inventory will provide missing information about oil and gas operations and will supplement the limited information provided on other aspects of those operations to assist the Commission in identifying emission sources appropriate for further emission reduction strategies.

Additionally, this inventory will also help Colorado move forward in beginning to address the broad greenhouse gas directives in SB 19-096 (Concerning the collection of greenhouse gas emissions data to facilitate the implementation of measures that would most cost-effectively allow the state to meet its greenhouse gas emissions reductions goals) and HB 19-1261 (Concerning the reduction of greenhouse gas pollution, and, in connection therewith stablishing statewide greenhouse gas pollution reduction goals). This inventory is separate and apart from the APEN reporting and fee structure in Regulation Number 3, though the Commission expects that the Division, in consultation with stakeholders, will consider ways to align the reporting programs in the future to minimize duplication.

Operators will be required to submit a company-wide report on June 30 of each year for the preceding year. The first report will be due on June 30, 2021, covering emissions from July 1, 2020, through December 31, 2020. Operators are required to use the Division-approved form. The Commission expects that the Division will consult with stakeholders in the development of this form (or forms). The Commission understands that some of the emissions source category activities and equipment are not currently well defined, nor is there necessarily a well understood method of calculation for emissions (e.g., downhole well maintenance). The Commission therefore directs the Division to work with stakeholders from the adoption of this regulation throughout 2020 to, among other things: (1) appropriately define each emissions source category, activity, and equipment; and (2) identify reasonable methods of calculation for each emissions source category activity and equipment. For some emissions source category activities and equipment, achieving both goals may not be realistic before recordkeeping must begin in July 2020. Therefore, for those limited categories, the Commission expects that the Division will identify parameters that may be reported (e.g., frequency and duration) until such time as the category can be well defined and an appropriate calculation method can be identified. The Commission's intent here applies also to the well emissions reported under Section II.G.

Operators will need to include actual emissions information for various air pollutants, specifically methane, ethane, VOC, CO and NOx, for each emissions source category activity and equipment, as well as company-wide. The Commission has determined that monthly emissions information should be submitted for the summer months (May through September), while emissions for the remaining months can be aggregated into the annual figures. The Commission recognizes that, over time, these emissions inventories are likely to reflect ongoing emission reductions from the industry resulting from both the continued implementation of emission reduction strategies and the refinement of emissions estimation techniques.

The Commission also recognizes that the emission estimation techniques used for inventory purposes may differ from regulatory methods for calculating, recording, and reporting emissions under the APEN and permitting program, and intends that such differences will be considered in any enforcement matter. It is critical that these inventories be as accurate and complete as possible, and operators are expected to perform quality assurance on the data prior to submittal. However, these inventories will require the submittal of a large amount of information, so operators are provided with timeframes for correcting information found to contain substantive errors. The Commission directed the Division to report back to the Commission in 2020 regarding the inventory and progress made.

<u>Ozone State Implementation Plan Revisions for Serious Reclassification (Part C, Section II.F. (new section in former Section X.; Part E, Sections II. and III. (formerly Sections XVI.D. and XIX.)</u>

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the CAA's Serious ozone nonattainment area requirements, as set forth in CAA Sections 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., major stationary sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, to address the CAA Serious RACT SIP requirements, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx (which became major sources as of the effective date of the reclassification to Serious). The revisions include expanding the applicability of the combustion equipment requirements, including the combustion process adjustment requirements, in Section II. to equipment located at facilities with NOx emissions greater than or equal to 50 tons per year; incorporating by reference NSPS and/or NESHAP requirements for specific points at some 50 tpy major sources in Section III.; requiring some sources submit RACT analyses to the Division in Section III.; and a new categorical rule regarding general solvent use in Part C, Section II.F.

Consistent with Senate Bill 19-181, House Bill 19-1261 and Senate Bill 19-096, the Commission directs the Division to propose regulatory recommendations to the Commission in 2020 regarding: pneumatic devices that do not vent gas; continuous emission monitoring; alternatives to combustion for emissions control; enhanced LDAR, especially near occupied dwellings; and other options to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain," Colo. Rev. Stat. Section 25-7-109(10)(a), including "pre-production activities, drilling, and completion," id. Section 25-7-109(10)(c).

To increase transparency and accountability, the Commission further directs that in 2020 the Division explore options for developing a publicly accessible and searchable oil and gas complaint filing and tracking tool, and to accept public input on the development of this tool. The Division will report back to the Commission on its progress in 2020.

<u>SIP Streamlining (Part B, Sections IV. and VII. (formerly Sections VI. and XV.) & Appendices B, C, and E)</u>

As a SIP clean-up effort, the Commission adopted revisions to Regulation Number 7, Part B, Sections IV. and VII. and removed Appendix E so the requirements align with current EPA methods and requirements.

In 1980, the Commission adopted requirements in Regulation Number 7, Section IV. requiring an annual pressure test for gasoline transport trucks. Those requirements were based on EPA's Control Techniques Guidelines (CTG) Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (December 1978) and included the test procedures for annual pressure and vacuum testing of gasoline transport trucks, as outlined in Appendix E. In 1980, The Commission also adopted Appendix B which specifies the criteria for controlling vapors from gasoline transfer to storage tanks. Those requirements are based on EPA's CTG Design Criteria for Stage I Vapor Control Systems Gasoline Service Stations (November 1975). EPA approved these provisions into Colorado's SIP in 1995.

Since the publication of EPA's CTGs, EPA has published similar requirements for gasoline transport trucks in EPA's NSPS Subpart XX Standards of Performance for Bulk Gasoline Terminals (40 CFR Part 60, Subpart XX (August 18, 1983, last revised December 19, 2003)); NESHAP R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) (40 CFR Part 63 Subpart R (December 14, 1994, last revised April 6, 2006)); NESHAP Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (40 CFR Part 63, Subpart BBBBBB (January 10, 2008, last revised January 24, 2011)); and NESHAP Subpart CCCCCC National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC (January 10, 2008, last revised January 24, 2011)). These federal standards reference EPA's Method 27, Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test, in contrast to the CTG's pressure-vacuum test.

The Commission adopted provisions to replace the outdated vacuum-pressure test in Regulation Number 7 with the more current EPA Method 27. The Commission also updated the test values in Regulation Number 7, which are based on EPA's CTG but also correspond to the EPA Method 27 test values in EPA's NSPS XX, NESHAP R, NESHAP BBBBBB, and NESHAP CCCCCC. The Commission also revised the recordkeeping and certification requirements in Section IV. to correspond to EPA's Method 27 and federal standards. Lastly, the Commission clarified the requirements for owners or operators using vapor collection systems that such systems must be leak-tight and properly maintained and operated.

These revisions will update Colorado's SIP and align the gasoline transport truck, terminal, and service station control and testing requirements with current EPA NSPS and NESHAP standards.

<u>Miscellaneous</u>

The Commission has also adopted revisions to provisions not discussed in detail in order to facilitate and align the substantive revisions identified, including revisions to the Applicability in Part A, Section I.A., and exemptions in Part A, Section II.B.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

<u>Incorporation by Reference</u>

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

<u>Additional Considerations</u>

Colorado must revise Colorado's ozone SIP to address the ozone serious nonattainment area requirements. The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 that are unrelated to the reclassification to serious to update and streamline requirements for gasoline transport trucks, terminals, and service stations to align with current federal requirements; therefore, these revisions do not exceed or differ from the federal act or rules thereunder. Further, the Commission adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Sections II. (except II.C.1.b.(ii) and II.F.), III.F., IV., and V. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including storage tanks, storage tank loadout, fugitive emissions from components, pneumatic controllers, and downstream transmission operations. The proposed revisions also include an annual oil and gas sector emissions inventory report. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, the Greenhouse Gas Reporting Program (GHGRP), and Pipeline and Hazardous Materials Safety Administration (PHMSA) may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks and fugitive emissions components then the NSPS and NESHAP and more facilities and operations than the GHGRP and PHMSA.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (> 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part E, Sections II. and III. to include categorical RACT requirements for combustion equipment at major sources of NOx and incorporate by reference federal standards for specific sources or points. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment. The Commission also revised Regulation Number 7 to include categorical RACT requirements for general solvent use and is not aware of federal rules applicable to general solvent use.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Part D, Sections I. through IV. strengthen Colorado's SIP state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections II.F. recognize practices currently utilized by solvent operations. The revisions to Regulation Number 7, Part E, Sections II. and III. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D, Sections I. through V. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C, Sections II. and Part E, Section II. similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, or if Colorado continues to fail to achieve the NAAQS, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing an annual oil and gas inventory report are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for storage tanks and component leaks. Other revisions reflect changes in industry practice, such as for solvent use. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) The revisions adopted will reduce significant amounts of VOC and methane, addressing both Colorado's ozone problems and making strides to reduce the impact of climate change. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements related to LDAR, pneumatic devices, monitoring, and the transmission segment. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

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

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

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

Hundreds of people from across the state submitted written comments on the proposed changes to Regulations 3 and 7. Most of these written comments called for additional regulation of oil and gas operations, to fulfill the directives of SB 19-181, protect public health, and reduce greenhouse gas emissions. Prior to the rulemaking hearing, the Commission held public comment sessions in Rifle, Durango, and Loveland, on December 10, 11 and 16, respectively. Dozens of members of the public spoke at each of these sessions. Many commenters expressed support for the proposed changes to Regulations 3 and 7, citing concerns about risks to health and to the climate from oil and gas emissions. Many commenters at the Rifle and Durango meetings emphasized the need for rules to be applied statewide. Commenters also called on the Commission to develop requirements for continuous monitoring of oil and gas emissions. Some speakers at each comment session expressed concern that the industry was being overregulated, with some on the Western Slope emphasizing that their part of the state was in attainment with ozone standards and expressing concerns with the impact more stringent rules might have on the industry.

T. September 23, 2020 (Part D, Sections II., IV., V., VI. and Part E, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act § 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission’s (Commission) Procedural Rules.

<u>Basis</u>

The Commission revised Part E, Section I. to reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) greater than or equal to 1,000 horsepower (hp) on a state-wide basis. The revisions are in response to four distinct directives to secure reductions: Senate Bill 19-181 (SB 19-181); the second implementation period of the Regional Haze Rule pursuant to Clean Air Act Section 169A; progress towards the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb and 2015 ozone NAAQS of 70 pp; and to address nitrogen deposition at Rocky Mountain National Park (RMNP).

The Commission also revised Part D, Sections II.G., IV., and V. to include annual reporting of carbon dioxide (CO2) and nitrous oxide (N2O) and Section V. to include additional emissions reporting from class II disposal well facilities. The Commission adopted a new Part D, Section VI. requiring owners and operators of pre-production oil and gas operations to monitor pollution during pre-production (i.e., drilling through flowback) and early-production and to control emissions from pre-production tanks and vessels (i.e., flowback vessels). Lastly, the Commission expanded the requirements in Part D, Section II. to control emissions from hydrocarbon liquids loadout at class II disposal well facilities. These proposed revisions are a next step in addressing the directives of SB 19-181, SB 19-096, and HB 19-1261, building upon revisions adopted by the Commission in December 2019.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, et seq. (Act), specifically § 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations. Sections 25-7-109(1)(a), (2), and (3) authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources; emission control regulations pertaining to NOx, hydrocarbons, and hazardous air pollutants; and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane, and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Purpose

To address SB 19-181, SB 19-096, HB 19-1261, ozone, visibility, and nitrogen deposition, the Commission adopted revisions to Regulation Number 7 that limit emissions from engines, limit emissions from pre-production tanks, reduce emissions from hydrocarbon liquids loadout at class II disposal well facilities, require reporting of emissions from class II disposal well facilities, expand annual reporting to include additional greenhouse gases, and require monitoring at pre-production and early production oil and gas operations. These revisions are all adopted on a state-wide and state-only basis.

Engines (Part E)

The Commission adopted requirements in Part E, Section I. to minimize emissions from natural gas fired RICE. The requirements apply to natural gas fired RICE greater than or equal to 1,000 HP. The requirements are responsive to SB 19-181 as it applies to engines used in the oil and gas sector, as well as securing NOx reductions that will also reduce ozone, visibility, and nitrogen deposition at RMNP.

Except for the combustion process adjustment requirements for engines at major sources, the Commission has not revised the requirements pertaining to engines since 2010, and emissions from engines associated with oil and gas production in Colorado have continued to increase. While the Commission recognizes the twin challenges currently faced by the oil and gas industry in Colorado - the COVID-19 pandemic and low oil prices - this regulation’s provisions for phasing in compliance over time and, particularly, the unique characteristics of the Alternative Company-Wide Compliance Plan (Company-Wide Plan, affords the industry the flexibility necessary to achieve emission reductions necessary to protect public health and the environment in a cost effective manner.

Applicability (Section I.D.5.a.)

The Commission adopted a new subpart, Section I.D.5., to establish state-only standards to reduce emissions from a subset of existing stationary engines operating over or equal to 1,000 HP and those placed in service, modified, or relocated after November 14, 2020. As defined in the rule, “placed in service” addresses when an engine is brought to a site for utilization. “Placed in service” is a new term that deviates from the Division and industry’s traditional reliance on the defined term “commence construction” or NSPS JJJJ’s reliance upon manufacture date.

The Commission is clarifying when replacement of an engine under an authorized alternative operating scenario (AOS) would not trigger the engine to be subject to the standards in Table 2 for engines “placed in service” after November 14, 2020. Subsequent replacements under an authorized AOS also would not trigger the replacement engine to be subject to the standards in Table 2 for engines “placed in service” after November 14, 2020. If an engine is replaced under an AOS, while it may not trigger the lower standards based on “placed in service,” it may nonetheless trigger the lower standards if it is “relocated” – i.e. if the replacement engine is brought into Colorado from outside Colorado, or brought into the nonattainment area from outside the nonattainment area. The return of an engine to the same site from which it was removed for the sole purpose of repair or maintenance is not considered “placed in service” or “relocated” for purposes of this Section I.D.5.

The Commission also adopted a different framework for “relocated” engines in Regulation Number 7, Part E, then in Regulation Number 6, Part B, which provides that engines brought to a site from another location in Colorado are not considered “new” and are not subject to the more stringent standards of the applicable NSPS. Under Regulation Number 7, there are only two exceptions to when an engine is considered new: when an engine is replaced under an alternative operating scenario (AOS) in an existing permit, which requires the engine to meet the same standards as the engine replaced, or when an engine subject to a Company-Wide Plan is moved from one site to another site with the same owner or operator. When an engine is subject to a Company-Wide Plan, the operator will have more flexibility to move an engine as long as it achieves at least the same emission reductions under the plan. However, an engine brought into the 8-Hour Ozone Control Area is considered “relocated” and must meet or exceed the standards as of the date it begins operation, whether or not it is subject to a Company-Wide Plan.

Emission Standards (Section I.D.5.b.)

The Commission adopted different emission standards based on engine configuration and the date that the engine was placed in service, modified, or relocated. The Commission intends that the applicable engine configuration is determined by the most current Division-issued permit or APEN filed prior to November 14, 2020. If the engine configuration is not identified in a Division-issued permit or APEN, the owner or operator is required to submit an APEN with this information to the Division by May 1, 2021. After November 14, 2020, any change to the identified configuration that results in an emissions increase is considered a modification.

The Commission adopted, generally, more stringent NOx standards applicable to engines placed in service, modified, or relocated after November 14, 2020. However, for 2-stroke lean burn engines, the NOx standard is the same whether the engine is currently in use at a site or brought on at a later date. The Commission also intends that any engines subject to a more stringent standard under a permit or other rule, such as Section I.D.2.b. of Regulation Number 7, must still comply with that more stringent limit. The Commission adopted varying timing requirements for owners or operators to meet the emission standards, based on the location of subject engines inside and outside of the 8-Hour Ozone Control Area. Owners or operators with any engines in the 8-Hour Ozone Control Area are subject to a more aggressive timeline, which requires 100% of engines inside the 8-Hour Ozone Control Area to meet the emission standards by May 1, 2024, and 100% of engines outside the 8-Hour Ozone Control Area meet the emission standards by May 1, 2026. Operators with no engines inside the 8-Hour Ozone Control Area must follow the second timeline and meet the standards of at least 20% of engines each year from 2022 to 2026.

The Commission intends that the emission standards in Table 2 are a gram per horsepower-hour limit based on appropriate averaging times. The Commission also intends that operators demonstrate compliance with the certification and recordkeeping requirements through the performance testing results required by Section I.D.5.d and the portable analyzer results obtained in accordance with Section I.D.5.e., using the appropriate averaging times.

The Commission requests that the Division consider evaluating strategies to increase the electrification of engines, lower emissions standards for engines, and possible controls applicable to smaller engines.

Notification to Division (Section I.D.5.b.(iii))

If an owner or operator has subject engines, the owner or operator must submit a notice to the Division no later than May 1, 2021. However, the owner or operator of engines covered by a Company-Wide Plan will not need to submit the information required by Section I.D.5.b.(iii) for all engines.

Permit Modification (Section I.D.5.b.(iv))

The Commission adopted two deadlines for when a permit modification application is required. If the engine can meet the standards through only a permit modification, the application is due May 1, 2021. If the engine cannot meet the standards through only a permit modification, the application is due 365 days prior to that engine's compliance deadline. An example of the first scenario is where an engine currently permitted with a high emission rate can meet the standards if operated at a lower emission rate and it is, in fact, already operating as of November 14, 2020, at that lower emission rate. In contrast, an example of the second scenario is where an engine is permitted at an emission rate above the applicable standard and operates at its permitted level, which would require the operator to change the operation of the engine in order to comply. This engine, therefore, would have a compliance date in accordance with Section I.D.5.b.(v)(B), and the permit application would be due 365 days prior to that engine's compliance deadline. Stakeholders expressed concerns that the Division may not be able to timely process all of the permit modifications. Therefore, the Commission determined that the flexibility outlined in the rule was necessary for both industry and the Division. In the case of a pending permit modification, the Commission intends that the most current APEN requested limits will be used to determine compliance with the rule.

Industry stakeholders have expressed that the rules need to be more accommodating for Division delays in permit issuance for those situations where owners and operators cannot take action to comply with the emission standards without a permit in hand. Industry notes that without a revised permit, owners and operators would be out of compliance with federal and state permit requirements, leaving the operator with the choice of what standards to comply with. Based on information provided by these stakeholders, the Division believes that there are only 15 such permits. Additionally, the vast majority of engine upgrades do not necessitate a permit modification prior to completing the upgrade.

The Division has indicated that it has enough dedicated staff to complete the required permit modifications in a timely fashion so long as the operator submits the permit application at least one year in advance of the compliance deadline. To address stakeholder concerns, the Commission expects the Division to work with operators that require a permit prior to commencing upgrades and create a process to give these permit applications priority. Should any permits push up against the one-year issuance deadline, the Division, in its discretion, will evaluate any potential operator compliance deadline extensions on a case-by-case basis.

Alternative Company-Wide Compliance Plan (Company-Wide Plan) *(Section I.D.5.c)*

The Commission adopted a Company-Wide Plan option to allow flexibility for each owner or operator to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emission reductions than would be achieved through compliance with the emission standards on an individual engine basis.

The Company-Wide Plan requires an overall emissions percentage reduction based on company-wide engine operations. Owners or operators using this option must demonstrate that the total NOx emissions allowed under the Company-Wide Plan are less than or equal to the total NOx emissions allowed through compliance with the emission standards on an individual engine basis. Engines included in a Company-Wide Plan remain subject to the performance testing, monitoring, recordkeeping, and reporting requirements.

This Company-Wide Plan option is available only to owners or operators with five or more engines that are subject to Section I.D.5.b(v)(B). For purpose of the Company-Wide Plan only, the term owner/operator refers to owners or operators that are participating in a Company-Wide Plan and are owned or operated by the same parent company. Engines that already meet the emission standards of Table 2 but only need a permit modification to reflect compliance may not be part of a Company Wide Plan for which credit is claimed by the operator. However, if the operator makes a further retrofit to the engine, the operator may include that engine in the Company Wide Plan and claim credit for the reductions achieved by the further retrofit. For example, if Engine A, a 4-stroke lean burn engine, has a permit limit of 1.8 g/hp-hr, but currently operates at 1.2 g/hp-hr, Engine A would not be included in the Company Wide Plan. However, if the operator installs additional control technology such that Engine A can now operate at 1.0 g/hp-hr, the emission reductions associated with the drop in emissions from 1.2 g/hp-hr to 1.0 g/hp-hr can be included in the Company-Wide Plan. Only physical retrofits, and not operational changes, can be accounted for in this manner.

Owners or operators will submit a notification (referred to as a compliance plan) using a Division-approved form that will be developed with stakeholder input. Recognizing that the Company-Wide Plan is intended to afford flexibility only where it will achieve the same or better reductions, the Commission has provided for detailed information to be submitted to the Division for review. The information submitted will allow the Division to compare the emission standards and operating conditions that an engine is meeting before and after the Company-Wide plan as well as the maximum emissions permissible if all Company-Wide Plan engines complied individually with the standards versus the permissible emissions under the Company-Wide Plan.

Owners or operators must calculate “Plan Emission Reductions” - i.e. a summation of NOx emission reductions from all engines in the Company-Wide Plan. This figure is calculated by looking at the maximum amount of NOx emissions from the engines before November 14, 2020 (using the current permitted emission rate) and subtracting the maximum amount of NOx emissions that will be allowed from those engines under the Company-Wide Plan.

Owners or operators must also demonstrate that the Company-Wide Plan will result in real emission reductions, and the Division is directed to disapprove any Company-Wide Plan that the Division determines does not achieve those reductions. Owners or operators will calculate the estimated historic emissions from the plan’s engines in tons per year as a baseline, using the most stringent regulatory or permitted emission standards and operating conditions in conjunction with actual operating hours (averaged over 2017-2019). That baseline figure is then compared to the maximum amount of emissions permissible from the Company-Wide Plan engines to ensure that the Company-Wide Plan will result in emission reductions. The demonstration also includes a comparison of the emission reductions that would be achieved from the actual baseline figure if each engine complied with the emission standards on an individual basis to the reductions that will be achieved under the Company-Wide Plan. In this way, the Commission seeks to ensure that a Company-Wide Plan achieves demonstrable reductions in NOx emissions.

Owners or operators will not be allowed to utilize reductions in permitted operating hours to offset emission reductions that would otherwise be achieved where permitted hours are higher than actual hours of operation (on average over 2017, 2018, and 2019). For example, an operator with a permit to operate at 8,760 hours per year but that operated only at 5,000 hours per year (on average over 2017, 2018, and 2019) cannot modify its permit to lower the permitted hours of operation to 5,000 and thereby create NOx emissions for which it can take credit in its Company-Wide Plan.

Some stakeholders have expressed concerns over how engines that began operation during or after the averaging years will calculate “historic” emissions. For these types of engines, the Commission expects that the most recent year(s) of operation should be used to calculate “historic” emissions. If there is less than one year of operation during this time frame, the Commission expects that the operator should extrapolate the available operation emission data to one year to estimate “historic” emissions.

Owners or operators must also submit notice of relocated engines in the annual update to the Company-Wide Plan, beginning in 2022. A relocated engine will be categorized by its new location (inside or outside of the 8-Hour Ozone Control Area) for purposes of the engine's compliance deadline.

To assist with implementation, the Commission directs the Division to provide timely guidance to the regulated community as to how to develop a Company-Wide Plan. The Commission recognizes that the Company-Wide Plan provisions are complicated, and believes providing the following examples of how the Commission intends the program to work will be helpful.

Example 1:

An engine in a Company-Wide Plan is located inside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), also within the 8-Hour Ozone Control Area. The engine was not "placed in service" or "relocated" within the meaning of this rule, and compliance deadlines would not change. The owner/operator just submits the new location in its annual update.

Example 2:

An engine in a Company-Wide Plan is located outside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), except that site B is located inside the 8-Hour Ozone Control Area. The engine is not "placed in service" within the meaning of this rule but it is "relocated." The engine's relocation into the 8-Hour Ozone Control impacts both the standard with which it must comply and the timing of when the new standard must be achieved.

If the engine was not proposed for retrofit or if it was proposed for retrofit but under the Company-Wide Plan it would not meet the standard, the engine will need to meet the emission standards as of its date of operation following relocation. If the engine was proposed for retrofit to achieve performance below the emission standards (retrofit/shut-down, etc.), the engine must meet the more stringent of either the applicable standard or the proposed Company-Wide Plan standard as of the date of operation following the relocation date.

Conversely, if an engine subject to a Company-Wide Plan located in the 8-Hour Ozone Control Area is moved to a different site (same owner/operator) outside of the 8-Hour Ozone Control Area, the engine is not "placed in service" or "relocated" within the meaning of this rule. The engine must meet the standard specified in the Company-Wide Plan consistent with the applicable compliance date.

Example 3:

Operator A has 20 engines and submits a Company-Wide Plan that includes modifying five engines (in 2022 and 2023) and shutting down two engines (in 2024). Operator A then transfers ownership of one of the engines (either the engine or the entire facility) to be shut down to Operator B; that shutdown would have achieved 20 tons per year (tpy) NOx reduction. Operator A must find an additional 20 tpy NOx reduction from the 19 engines remaining in its Company-Wide Plan.

Example 4:

A Company-Wide Plan includes shutting down an engine. The operator then realizes it needs a replacement engine at that same site. The operator has a few options. First, the operator can amend its Company-Wide Plan to no longer shut down the engine (assuming the engine's compliance deadline has not yet passed) and can identify other actions to be taken to achieve the emission reductions that would have otherwise been realized from the shutdown of the engine. Second, the operator can shut down the engine as originally intended and bring on a new engine. The new engine will be subject to the emission standards as an engine "placed in service" after November 14, 2020, and cannot be a part of the operator's Company-Wide Plan because an engine scheduled for shut down under a Company-Wide Plan cannot be replaced with a different engine subject to the Company-Wide Plan. Because the operator must comply with the Company-Wide Plan, the operator will still need to cancel the APEN and permit for the existing engine and permit the new engine as a new source.

Example 5:

An operator has ten engines subject to a Company-Wide Plan and intends to modify five of those engines to achieve the required Plan Emission Reductions. However, in order to meet the CO standards for one of the engines that will not be modified to achieve Plan Emission Reductions, the operator must make an adjustment that has the effect of increasing NOx emissions from that engine. In calculating the maximum allowable NOx emissions from engines in the compliance plan and Plan Emission Reductions required, the operator must account for the increase in NOx emissions from the engine.

Performance Testing, Monitoring, Recordkeeping, and Reporting (Sections I.D.5.d., I.D.5.e., I.D.5.f., and I.D.5.g.)

The Commission adopted performance testing requirements to establish a baseline for evaluating an engine's performance – i.e. to enable an operator to know whether the engine was meeting the standards already or how much action might be required to meet the standards. To conserve the resources of both the Division and the operators, the Commission has allowed for operators to rely on existing ongoing semi-annual portable analyzer testing requirements, as well as performance testing conducted under NSPS JJJJ, a permit, or testing conducted voluntarily after January 1, 2020.

The Commission also adopted semi-annual portable analyzer testing requirements. The portable analyzer monitoring must commence within twelve (12) months of the initial performance test. The Commission intends that operators will conduct two portable analyzer tests in 2022, the first of which must be completed by June 30, 2022.

The Commission has also adopted new monitoring, recordkeeping and reporting requirements. With respect to oil and filter changes under Section I.D.5.e.(iv)(A), the Commission acknowledges that the development of an oil analysis program that tests to ensure that oil does not need to be changed meets the requirements of that section.

In the recordkeeping section, the Commission requires that for both performance tests and portable analyzer tests, the owner or operator retains records regarding the date, engine settings on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission acknowledges that maintaining the test reports (for performance tests) and maintaining records consistent with the Division's Portable Analyzer Monitoring Protocol (for portable analyzer test), is sufficient to demonstrate compliance with the requirements to maintain the date, engine setting on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission has required the reporting of the results of performance tests (Section I.D.5.g.(i)) and semi-annual portable tests (Section I.D.5.g.(iv)). By "results," the Commission means that the owner/operator shall indicate whether the tests were passed or failed. Other, more detailed results are required to be maintained as part of the recordkeeping requirements and will be available to the Division upon request.

General provisions (Section I.D.2.)

In 2019, the Commission adopted a reorganization of Regulation Number 7 moving like-sections together, including engines. The Commission now completes the reorganization of the engine sections by duplicating the applicable general provisions that applied to engines in Part D, Section II. (formerly numbered Section XVII.) in Part E, Section I.D.2. These provisions will continue to apply to engines addressed in Part E, Sections I.D.3. and I.D.4. (formerly Sections XVII.E.) and will also apply to engines addressed under the new Part E, Section I.D.5.

<u>Oil and gas operations (Part D)</u>

The Commission expanded or adopted additional requirements in Part D to further minimize emissions of greenhouse gases, ozone precursors, and other hydrocarbons from the oil and gas sector.

Pre-production and early production monitoring

The Commission adopted a new Section IV. that requires owners or operators to monitor air quality at and/or around pre-production operations (i.e., drilling, fracturing, drill-out, flowback) and early production operations (i.e., six months). The purpose of this air quality monitoring is multi-faceted in that the Commission anticipates the monitoring program will gather information about the evolving oil and gas monitoring technologies, data about potential emissions during pre-production and early production operations (e.g., ozone precursor emissions, greenhouse gas emissions, hazardous air pollutants), and inform future monitoring efforts. Owners or operators will also monitor air quality for ten days prior to beginning pre-production operations. The Commission recognizes that ten days does not provide a comprehensive or long-term baseline but intends that it cover day-of-week variability in surrounding activities and short-term meteorological variability, in order to provide a reference point for interpreting subsequent data.

Owners or operators must submit an air quality monitoring plan to the Division for approval prior to monitoring air quality. The Commission created a flexible air quality monitoring program that allows the operator to specify what pollutant(s) representative of pre-production and early production hydrocarbon emissions will be monitored and by what monitoring technology. The Commission anticipates that the additional elements of the air quality monitoring plan, such as monitor siting, frequency of measurements, monitoring equipment limitations, and ability to trigger or collect speciated samples, will vary based on the monitoring objectives and technology utilized.

The Commission also anticipates that the response level(s) will vary based on the monitoring technology, monitor placement, the pollutant(s) monitored, data collection and averaging times, and other factors. The response level may differ from a lower detection level established by the owner or operator that triggers an initial investigation of potential emissions at the facility. The Commission expects that the monitoring technology selected will have a detection ability sufficient to detect the pollutant(s) monitored at an appropriate level above area concentrations such that the monitoring objectives (e.g., detect ozone precursors, detect hazardous air pollutants, detect greenhouse gas emissions, associate elevated monitored values to an emission source within the monitored operations) are achieved. The Commission recognizes that not every elevated measurement constitutes a detection requiring a response but instead may be accompanied by analytics evaluating the measurements in comparison to an emission source or activity. The Commission also expects that placement of the monitors will be designed to be adequate to meet the objectives of the monitoring plan and that operators will select a monitoring technology that collects measurements at short-term intervals (e.g., 1 minute, 15 minutes, 1 hour) and appropriate sensitivity.

For example, concentrations at 2000-4000 feet away from the operations are likely to be low and, therefore, would require high-sensitivity instruments; monitors placed in close distance to the operations may need to be placed at variable heights to detect emissions from equipment of different heights; or monitors may need to be placed in both upwind and downwind locations, depending on the monitoring technology. In addition, the Commission expects the Division to work with operators in approving air quality monitoring plans to make sure that local jurisdiction air quality monitoring requirements and COGCC site preparation requirements are considered. The Commission expects the Division to consult with relevant local governments in reviewing monitoring plans, to obtain their input on local circumstances or concerns that may guide the Division's determinations on plan adequacy.

Owners or operators will also submit monthly reports of air quality monitoring to the Division. These monthly reports will include descriptions of activities that occurred during the monitoring period such that monitoring data can be understood in relation to activity onsite (e.g., accounting for engine emissions). The Commission recognizes that monitoring data often requires additional analysis to interpret the resulting data. Therefore, for this first oil and gas air quality monitoring program, the Commission expects that operators will make the raw data (e.g., monitor/sensor and meteorological readings prior to analysis or processing) available to the Division upon request (and expects the Division to make the raw data available to the relevant local government entities upon request) but submit the analyzed data results in the monthly reports. The Commission believes these reports will provide valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make the reports publicly available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. This flexible monitoring program is intended as an initial step to help inform future oil and gas monitoring efforts.

Recognizing that this pre-production emissions monitoring program represents a first step in understanding both pre-production emissions and the rapidly evolving technologies that may be used to monitor them, the Commission directs the Division to report back to the Commission no later than March 31, 2022 with an initial summary of activities to implement the rule since September, 2020; learnings and insights on monitoring technologies, including technologies for continuous methane monitoring; appropriate data summaries on observed emissions based on the monthly reports received; initial feedback on the adequate length of monitoring time during and possible identification of exemptions from monitoring for certain types of facilities.

Flowback vessels

The Commission also adopted in the new Section VI. a requirement for owners of operators of pre-production operations to control emissions from flowback vessels. After hydraulic fracturing, operators bring the frac fluids and entrained solids to the surface. EPA's NSPS OOOOa Section 60.5375a requires operators to route flowback during the initial flowback stage into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. During the separation flowback stage, NSPS OOOOa requires operators to route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into a well, or route the liquids to a collection system. NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to control well completion vessel emissions. Therefore, to build on the NSPS reduced emission completion requirements and further reduce pre-production tank emissions, owners or operators of pre-production operations must use enclosed flowback vessels after the drill-out phase, which the Commission recognizes has a high ratio of solids to liquids, and route emissions from flowback vessels to air pollution control equipment.

Class II disposal well facilities

The Commission added a new definition of class II disposal well facilities. This definition is based on EPA's Underground Injection Control Program: Criteria and Standard definition of class II well (see 40 CFR Section 146.5(b)(1)). The Commission did not include the element of EPA's definition concerning enhanced recovery of oil or natural gas as storage tanks related to those activities are considered part of the associated well production facility. The Commission recognizes that some class II disposal well facility operators interpret Part D, Section II.C. such that their storage tanks have not been subject to the storage tank control requirements. Although the Commission understands that the Division intended Part D, Section II.C. to apply to storage tanks serving class II disposal well facilities, the Commission also recognizes that a good faith argument existed under the prior rule language to support the alternative interpretation. The Commission intends for the Division to work with owners or operators to address implementation concerns that may arise including related to the May 1, 2021, state-wide compliance deadline for controlling emissions from storage tanks > 2 tpy and associated monitoring requirements as well as concerns related to the need for supplemental fuel to control emissions.

The Commission also expanded the hydrocarbon liquids loadout requirements in Part D, Section II.5. to hydrocarbon liquids loadout at class II disposal well facilities. Operators inject fluids, primarily brines, associated with oil and natural gas production into class II wells. Current regulatory requirements in the Safe Drinking Water Act for class II wells relate to the construction, operation, and monitoring of the well. The Safe Drinking Water Act does not require emissions reporting or storage tank or loadout emissions controls at class II disposal well facilities. Therefore, the Commission expanded the hydrocarbon liquids loadout requirements to class II disposal well facilities to reduce emissions from these operations.

The Commission directs the division to evaluate potential emission issues associated with load ins at class II disposal facilities

Annual emissions reporting

In 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, CO, ethane, and methane emissions to the Division on an annual basis. To further address and inform the GHG directives of Senate Bill 19-096 and House Bill 19-1261, the Commission expanded the reporting requirements to include the reporting of CO2 and N2O emissions from Colorado's oil and gas sector.

As described, the Safe Drinking Water Act does not require emissions reporting. Therefore, the Commission also clarified and expanded the annual emissions reporting requirements for class II disposal well facilities to better understand the emissions from these facilities and activities. Related to the fluids accepted for injection disposal, the Commission is requiring owners or operators to take periodic samples of the liquids to inform emission estimates. Acknowledging that fluid intake and facility designs may differ, the Commission expects the Division will work with owners and operators to develop sampling frequencies and protocols and to ensure accurate and consistent methods are used for emissions estimation and reporting. Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

<u>Incorporation by Reference</u>

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission includes reference dates to rules and reference methods incorporated in Regulation Number 7.

Community Engagement

Section 25-7-105(e) requires engagement with disproportionately impacted communities, other state agencies, stakeholders, and the public. The Division provided multiple ways for the public, local governments, industry, environmental groups, and other stakeholders to provide comment during the development of the proposed rules, including email and remote stakeholder meeting participation.

Additional Considerations

The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and Regional Haze Rule and requires Colorado to attain the NAAQS and reduce visibility. Therefore, the Commission adopted certain revisions to Regulation Number 7 to reduce VOC and NOx emissions in Colorado. In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including engines, pre-production operations, and class II disposal well facilities storage tanks and storage tank loadout. The proposed revisions also revise the annual oil and gas sector emissions inventory report to include GHGs and class II disposal well facilities. NSPS JJJJ, NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, NESHAP ZZZZ, and the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR Part 98 may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks then the NSPS and NESHAP, more engines than NESHAP JJJJ, and more facilities and operations than the GHGRP.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. The Regional Haze Rule was also not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. And, Colorado must improve visibility in accordance with Regional Haze. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits. And, the current revisions will improve visibility across the state, in particular in Colorado's class I areas.

(V) Colorado must attain the 2008 ozone NAAQS by July 20, 2021, and the 2015 ozone NAAQS by August 3, 3021, or risk being reclassified. Colorado must make reasonable progress toward improving visibility or risk EPA establishing a federal regional haze plan for Colorado. EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. EPA has established a Regional Haze SIP submittal deadline of July 1, 2021. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 address emissions from engines and the oil and gas sector in a cost-effective manner, as detailed in the Economic Impact Analysis, allowing for continued growth of Colorado's industry.

(VII) The revisions to Regulation Number 7 establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado continues to fail to achieve the NAAQS or make progress to reduce visibility, EPA may promulgate Federal Implementation Plans; thus potentially determining requirements for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing and revising annual oil and gas inventory reporting are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for hydrocarbon liquid loadout. Other revisions reflect changes in industry practice, such as for controlling emissions from flowback vessels.

(XI) The revisions adopted will reduce NOx, VOC, and methane, addressing both Colorado's ozone problems, making strides to reduce the impact of climate change, and making progress to improve visibility. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in greenhouse gases, ozone, VOC, NOx, other hydrocarbons, impacts to visibility, and nitrogen deposition to address Regional Haze, SB 19-181, and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements for the oil and gas sector. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in the need for much more stringent requirements to reduce nitrogen deposition in RMNP, improve visibility in Colorado's Class I areas, and reduce ozone across the state but particularly in the DMNFR.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

To the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

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

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

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

U. December 18, 2020 (Part D, Section II.; Part E, Sections II., IV., and V.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

On December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb. Therefore, to ensure progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to include reasonably available control requirements (RACT) for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy; specifically, for foam manufacturing, boilers, turbines, landfill gas and biogas fired engines, and wood surface coating.

Statutory Authority

The State Air Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants. Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information.

Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

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

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources (> 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, and including categorical RACT requirements.

The Commission is also clarifying requirements related to leak detection and repair (LDAR) inspections. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Major source RACT

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the Clean Air Act's (CAA) Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR. Therefore, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx including a NOx emission limit for boilers between 50 MMBtu/hr and 100 MMBtu/hr, a NOx emission limit for landfill gas or biogas fired engines, NOx emission limits for combustion turbines, categorical requirements to reduce VOC emissions related to foam manufacturing, and expanded categorical requirements to reduce VOC emissions related to wood surface coating.

Boilers

In 2019, the Commission expanded the combustion equipment requirements adopted in 2016 and 2018 for the 100 tpy major sources to the 50 tpy major sources. Specifically, for boilers, the Commission adopted provisions requiring boilers greater than or equal to 50 MMBtu/hr at 50 tpy major sources to comply with a 0.2 lb/MMBtu NOx emission limit. The Commission now further expands the categorical RACT requirements to require 50-100 MMBtu/hr boilers at 50 tpy major sources to comply with a 0.1 lb/MMBtu NOx emission limits. The owners or operators of these boilers will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Engines

In 2019, the Commission expanded the NOx emission limit requirements for compression ignition reciprocating internal combustion engines (RICE) and combustion process adjustment requirements for stationary RICE. The Commission now further expands the categorical RACT requirements for engines to include landfill gas and biogas fired RICE and require the engines to comply with the NOx emission limit in EPA's NSPS JJJJ for landfill/digester gas fired engines. The owners or operators of these engines will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Turbines

In 2019, the Commission adopted provisions requiring turbines constructed before February 18, 2005, to comply with NSPS GG and turbines construction after February 18, 2005, to comply with NSPS KKKK. During review of the submitted SIP RACT requirements, EPA questioned Colorado's reliance on EPA's NSPS GG as RACT and requested Colorado consider the NOx emission limits in EPA's NSPS KKKK for Colorado's NSPS GG and pre-NSPS GG turbines at major sources. While the Commission does not agree that NSPS GG is inappropriate as SIP RACT for Colorado's NSPS GG and pre-NSPS GG turbines, the Commission revised the requirements for turbines to reference NSPS KKKK NOx emission limits for the turbines constructed before February 18, 2005, but retain the testing and monitoring requirements of NSPS GG. Turbines with CEMS that are capable of operating in both combined and simple cycle modes are to show compliance with a 30-day average. Similar to EPA's discussion in the preamble to NSPS KKKK, the Commission recognizes turbines may have emission spikes during unit startup and that, therefore intends the turbine NOx emission limits to be implemented as under NSPS KKKK. See 71 Fed. Reg. 38,482 at 38,488-38,489 (July 6, 2006) "While continuous compliance is not required, excess emissions during startup, shutdown, and malfunction must be reported." All turbines will continue to comply with good air practices for minimizing emissions, combustion process adjustment, and recordkeeping requirements.

Wood coating

In 2018, the Commission adopted requirements for wood furniture surface coating based on recommendations in EPA's Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations CTG (Wood Furniture CTG) (1996), including topcoat and sealer VOC content limits, work practices, and recordkeeping requirements. Wood furniture is defined to mean "any product made of wood, a wood product such as rattan or wicker, or an engineered wood product such as particleboard," which is not inclusive of all wood products such as doors. However, in EPA's A Guide to the Wood Furniture CTG and NESHAP (1997), EPA states that "States may choose to extend their rules to other operations. For example, some States have developed rules for manufacturers of wood products so they may include limitations for manufacturers of items such as musical instruments or doors." Therefore, the Commission expanded the wood furniture surface coating requirements to the surface coating of other wood products such as doors, door casings, and decorative wood accents.

Foam manufacturing

The Commission adopted new VOC control requirements for foam manufacturing operations. The new provisions affect three foam manufacturing operations, although one of the sources is modifying their permit to more accurately reflect their actual emissions and will, therefore, have VOC emissions below 50 tpy. These new provisions include emission control requirements, work practices, monitoring, and recordkeeping requirements for foam manufacturing operations.

LDAR (Part D, Section II.)

The Commission also adopted clarifying revisions to the leak detection and repair (LDAR) provisions the Commission adopted in December 2019 including clarification to applicability and requirements for recordkeeping and reporting. The clarifications to Sections II.E.4.c. and II.E.4.d. ensure that operators continue to determine applicability in accordance with the storage tank or facility emissions as they have since the LDAR program was adopted in 2014. The inclusion of recordkeeping and reporting elements specific to increased inspections based on location from occupied areas ensure that the Commission can evaluate the efficacy of the LDAR program. The Commission acknowledges that not all operators will need to conduct a precise analysis concerning their location in relation to occupied areas (i.e., proximity analysis) based on their general distance.

However, the Commission believes it is important for operators to provide at least general documentation that they considered their location, even if to describe an extreme remote location. The Commission also acknowledges that some operators may elect to comply with the increased frequency inspections for certain facilities without conducting a proximity analysis. Documentation of this decision to comply with the increased inspection frequency satisfies the proximity analysis requirement.

The Local Community Organizations proposed an alternate rule to establish shorter repair deadlines for leaks discovered at well production facilities within 1,000 feet of an occupied area. The Local Community Organizations, industry, and the Division negotiated and agreed to the final language adopted by the Commission. For leaks identified at a well production facility located within 1,000 feet of an occupied area, operators must make a first attempt to repair the leak as soon as practicable, but no later than five working days after discovery of the leak. If repair cannot be completed within five days and the leak is not stopped using other means, the owner or operator must notify the local government with jurisdiction over the location and the Division. Reasons why an operator may be unable to attempt or complete repair within five days include, among other things, inclement weather that prevents a timely repair or repair attempt or delays in procuring necessary heavy equipment and workover rigs. The industry parties also raised the issue about local government or other agency requirements potentially delaying repair. Such impacts to repair schedules should be considered as the program is implemented.

The Commission notes that it will be the operator's responsibility to demonstrate the need for the delay beyond five working days, and the Commission expects that operators will be able to explain the types of reasonable efforts the operator undertakes to avoid the delay (e.g., reasonable efforts in procuring the equipment). If a leak is detected at a facility without a proximity analysis, operators may conduct a proximity analysis and may follow the repair deadlines in Section II.E.7.a. if there are no occupied areas within 1,000 feet.

Consistent with the existing LDAR program, leaks detected are not subject to enforcement by the Division so long as the operator complies with the repair and recordkeeping requirements of Section II.E. However, as the Commission noted in 2014 and again in 2017, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Part D, Sections I.C, II.B, or II.C (as applicable), including the requirements to minimize emissions and to operate without venting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the serious ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), CRS, the Commission determines

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including fugitive emissions from components. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more fugitive emissions components then the NSPS. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (> 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part B, Section I. and Part E, Sections II. and V. to include categorical regulatory RACT requirements. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 2008 NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 strengthen Colorado's SIP and state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections I. recognize practices currently utilized by wood coating operations. The revisions to Regulation Number 7, Part E, also consider specific existing major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C and Part E similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for component leaks. Other revisions reflect changes in industry practice, such as for wood coating and foam manufacturing. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

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

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

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

V. February 18, 2021 (Part D, Section III.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for the Commission. SB 19-181 revised the Air Quality Control Commission's directives in § 25-7-109, CRS, to consider pneumatic device requirements. Additionally, in HB 19-1261, the legislature mandated a 26% reduction in GHG by 2025, 50% by 2030, and 90% by 2050 (from a 2005 baseline), §§ 25-7-102(2)(g), 25-7-105(1)(e)(II), CRS.

Further, on December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb. Therefore, to further minimize emissions from the oil and gas sector and ensure progress towards attainment of the 2008 and 2015 ozone NAAQS and necessary greenhouse gas emission reductions, the Commission is adopting revisions to Regulation Number 7 to require non-emitting controllers in certain situations.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7- 109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7 and includes the technological and scientific rationale for the adoption of the revisions. The revisions also correct typographical, grammatical, and formatting errors found through the regulation. As discussed, SB 19-181 identifies specific requirements the Air Quality Control Commission should consider, including pneumatic controller requirements. In December 2019, the Commission expanded the pneumatic controller inspection and maintenance requirements, adopted in 2017, from nonattainment area applicability to statewide applicability.

As part of that rulemaking, the Commission directed the Statewide Hydrocarbon Emission Reduction (SHER) team and Pneumatic Controller Task Force (PCTF), stakeholder processes directed by the Commission in 2017, to continue their stakeholder processes and bring to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Both the SHER team and PCTF continued to meet through the spring of 2020. The stakeholder discussions from 2017-2020 informed the Commission's adopted provisions regarding non-emitting controllers. Non-emitting controllers are a broader category than no-bleed pneumatic controllers and can include, but are not limited to, air-driven controllers, mechanical controllers, electric controllers, self-contained controllers and controllers where exhaust gas is routed to a combustion device.

Definitions

The Commission took the opportunity to amend the definitions associated with pneumatic controllers to reflect more accurate and appropriate technical definitions. The definition of "intermittent pneumatic controller" is intended to include controllers that are not designed to have a continuous bleed rate. Although intermittent pneumatic controllers are not designed to emit between actuations, de minimis emissions may occur between actuations. Such de minimis emissions do not alter a controller's classification as "intermittent."

New Facilities and Certain Retrofits

The revisions to Regulation Number 7 adopted in this rulemaking require the use of non-emitting controllers at well production facilities and natural gas compressor stations that commence operations on or after May 1, 2021. The revisions also require retrofits of natural gas emitting pneumatic controllers to non-emitting controllers at well production facilities where a well first begins production or is recompleted or refractured on or after May 1, 2021 and at natural gas compressor stations that increase horsepower on or after May 1, 2021.

Company-wide plans

Additionally, the Commission has required operators with well production facilities or natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert some of such facilities to use non-emitting controllers. For purposes of Section III.C.4, retrofit refers to converting a natural gas emitting pneumatic controller to a non-emitting controller. Plugging and abandoning an existing well production facility constitutes an alternative method of compliance with retrofit requirements as described in Section III.C.4.c.(iii). Specifically, the Commission has adopted a program that requires owners or operators of well production facilities that commenced operations prior to May 1, 2021 to determine the percentage of their total liquids production at facilities with non-emitting controllers. Facilities that commenced operation prior to May 1, 2021 shall be included in the relevant (well production or compressor station) companywide plan, and the companywide plan shall reflect operations as of May 1, 2021. If any of the events described in Sections III.C.4.a.(ii) or (iii) occur on or after May 1, 2021 and before May 1, 2023, then the owner or operator may count, as applicable, the: (1) percentage of production allocated to that facility as of May 1, 2021 as retrofit for purposes of the well production facility companywide plan; or (2) the pneumatic controllers emitting to atmosphere as of May 1, 2021 as retrofit for purposes of the compressor station companywide plan.

Where facility production must be estimated pursuant to Section III.C.4.c.(ii)(A)(3), owners or operators will follow the same process that would be used to establish permit limitations on production throughput, such as summation of anticipated production curves. Of note, if a facility operating in 2019 was subsequently acquired by a new operator, then the facility (and its percent of production) is associated with the company-wide plan of the entity owning the facility as of May 1, 2021.

Based upon this percentage, operators will be required to retrofit facilities incrementally by May 1, 2022 and May 1 2023; the required retrofits correspond to an increasing percentage of each operator's total liquids production flowing through facilities with non-emitting controllers. The incremental percentage increases for well production facilities are found in Table 1. Operators that increase their total non-emitting facility percent production up to a specified threshold are not required to achieve the entire incremental percentage increase that would otherwise apply for that year. However, the minimum incremental increases and specified thresholds do not restrict operators from exceeding the requirements.

Each well production facility operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, its total liquids production, facilities with non-emitting controllers, total percentage of liquid production flowing through facilities with non-emitting controllers, and the facilities that the operator intends to retrofit or plug and abandon in order to achieve the incremental increases in total liquids production flowing through facilities with non-emitting controllers. This company-wide plan should be updated in July 2022, with a final company- wide plan reflecting all facilities that were retrofit or plugged and abandoned submitted in July 2023.

The Commission has also required operators of natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert pneumatic controllers at such facilities to non-emitting controllers. Specifically, the Commission has adopted a program that requires operators to determine the percentage of emitting and non-emitting pneumatic controllers and based upon that percentage, operators will be required to increase the percentage of non-emitting controllers incrementally by May 1, 2022 and May 1, 2023. The incremental percentage requirements for natural gas compressor stations are found in Table 2. As for well production facilities, operators that increase their total percentage of non-emitting controllers up to a specified threshold are not required to achieve the entire percentage increase for that year that would otherwise apply. The minimum percentage increases and specified thresholds do not restrict operators from exceeding these requirements.

Each operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, total controllers, percentage of emitting and non-emitting controllers, the required incremental increases in non-emitting controllers, and the pneumatic controllers that the operator intends to retrofit or remove from service to achieve the incremental increases in non-emitting controllers.

For well production facilities and natural gas compressor stations, an owner or operator may elect to combine facilities with other owners or operators that are owned or operated by the same parent company in complying with company-wide compliance plan requirements.

At this time, operators will not be subject to the requirement to retrofit pneumatic controllers if they have facilities that on a company-wide basis, and taking into account only wells that produced oil or gas or both in calendar year 2019, averaged 15 barrels of oil and gas equivalent ("BOE") or less per day per well. However, in 2021, the Commission plans to consider additional emission reductions for the oil and gas sector that would enable the state to meet its ambitious climate goals as set forth in HB 19-1261. The Commission directs the Division to consider whether additional requirements to reduce emissions at the sites not subject to retrofit pursuant to Section III.C.4.c.(iv), including retrofit of pneumatic controllers, should be included in that rulemaking.

The requirement to submit an acknowledgement or certification under Sections III.C.4.c.(v) and III.C.4.d.(v) (regarding sale or transfer) does not apply to well production facilities or natural gas compressor stations that, at the time of sale or transfer are not intended to and will not be used to achieve the Total Required Non-Emitting Facility Percent Production or Total Required Non-Emitting Percent Controller target, as applicable. The following are each an acceptable means of ensuring compliance with Section III. following transfer through which owners or operators shall satisfy their obligations under Section III.C.4.c.(v) or Section III.C.4.d.(v), as applicable:

Example 1: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61%. Operator A is required to achieve an additional 5% of non-emitting facility percent production by May 1, 2022, and an additional 10% by May 1, 2023, with a Total Required Non-Emitting Facility Percent Production target of 76%. Operator A achieves the additional 5% of non-emitting facility percent production by May 1, 2022. In 2023, prior to May 1, Operator A transfer's ownership to Operator B of two well production facilities that Operator A had intended to retrofit with non-emitting controllers or plug and abandon in order to achieve its Total Required Non-Emitting Facility Percent Production. Retrofitting or plugging and abandoning those two facilities would have comprised half of the additional production required by May 1, 2023 (*i.e.*, 5% of Total Required Non-Emitting Facility Percent Production).

Scenario 1: Notwithstanding the transfer, Operator A may find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non-Emitting Facility Percent Production. In this case, Operator A does not need to submit an acknowledgement or certification upon transfer, but shall include this information in its next update to the Company-Wide Plan. This example would apply equally to transfers of assets subject to a Company-Wide Compressor Station Pneumatic Controller Compliance Plan.

Scenario 2: Operator A submits an acknowledgement, on a Division-approved form, that it will ensure the transferred asset is retrofit by May 1, 2023. Under this scenario, either Operator A or Operator B may undertake any necessary retrofitting (or plugging and abandonment) of the asset to allow Operator A to take credit for retrofit of the 5% of Total Historic Production, provided, however, that Operator A will remain responsible for retrofit of that asset to achieve its Total Required Non-Emitting Facility Percent Production. This means that if retrofit of the asset is not completed for whatever reason, Operator A would have to find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non- Emitting Facility Percent Production by May 1, 2023.

Scenario 3: Operator A submits an acknowledgement, on a Division-approved form, that it plans to use the transferred asset to achieve its Total Required Non-Emitting Facility Percent Production and Operator B certifies, on a Division-approved form, that it will retrofit the transferred asset by May 1, 2023. Upon certification by Operator B, Operator A shall receive credit for the retrofit of the 5% of Total Historic Production towards its applicable targets under Section III.C.4. The Division-approved form must include a statement that Operator B assumes Operator A's Section III.C.4 obligations with respect to the transferred asset and is, therefore, subject to the Division's enforcement authority in the event of noncompliance. Acquisition of the asset does not alter the calculation of Operator B's compliance with the percentage thresholds specified in Table 1 or 2 for its own Company-Wide Plan, if applicable.

Example 2: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61% and a Total Required Non-Emitting Facility Percent Production target of 76%. Operator B has a Total Historic Non-Emitting Facility Percent of 21% and a Total Required Non-Emitting Facility Percent Production target of 56%. Operator A and Operator B merge (or one entity acquires the other) in 2023, prior to May 1. Despite the merger, the resulting ownership of Operators A and B must continue to separately comply with the respective Company-Wide Plans and Total Required Non-Emitting Facility Percent Production targets of Operator A and Operator B that existed prior to merger.

Exemptions for Specific Controllers

The Commission has recognized that there are appropriate circumstances where even non-emitting facilities may need to use pneumatic controllers that emit natural gas to the atmosphere. Section III.C.4.e.(i)(A) authorizes use of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas. Starting May 1, 2021, new well production facilities or facilities where a well first begins production or is recompleted or refractured, and new compressor stations or stations that increase horsepower, must submit a justification for any safety or process exemption to the Division for approval 45 days prior to installation of the emitting device or retrofit of the facility. Owners or operators that intend to rely on this exemption to maintain emitting controllers at facilities that are retrofit under a company-wide plan must submit a justification to the Division 45 days prior to retrofit of the facility.

The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities and natural gas compressor stations commencing operation or taking actions described in Sections III.C.4.a.(ii) or (iii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(A)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Sections III.C.4.a.(ii) or (iii) occur. Section III.C.4.e.(i)(A), the requirement to seek Division approval is not applicable for: (1) well production facilities that qualify as contributing to Historic Non-Emitting Facility Percent Production, as defined in Section III.C.4.c.(ii)(D)(1) to (2), or (2) compressor stations that commenced operation before May 1, 2021.

Section III.C.4.e.(i)(B) authorizes use of pneumatic controllers that emit natural gas for activities that occur prior to the end of flowback and well abandonment activities. In addition, Section III.C.4.e.(i)(C) allows owners or operators, upon notice to the Division, to use temporary and portable equipment with pneumatic controllers that emit natural gas for sixty days for purposes other than increasing the throughput of the facility. The Commission directs the Division to develop a streamlined mechanism for filing these notifications, including evaluating the potential for electronic notification. Owners or operators must request Division approval to extend the sixty-day timeframe and must do so at least fourteen days prior to the end of the exemption period. Owners or operators utilizing temporary or portable equipment with pneumatic controllers that emit natural gas must conduct AVO and AIMM inspections of those controllers on the same schedule as the associated well production facility or compressor station under Section II.E., and must comply with the repair, recordkeeping, and reporting requirements of Sections II.E.6 through 9.

The requirement to use non-emitting pneumatic controllers at sites that commenced operations on or after May 1, 2021, or where one or more wells first begin production or are recompleted or refractured on or after May 1, 2021 does not apply in certain applications at some wellheads located away from the associated production facilities. Additionally, operators that have or retrofit well production facilities to be non-emitting pursuant to the company-wide plan may not be required to use non-emitting controllers in certain applications at some wellheads located away from the associated production facilities.

As set forth in Section III.C.4.e.(i)(D), operators may use natural gas actuated pneumatic controllers that emit to the atmosphere to control emergency shutdown devices or artificial lift control at a wellhead if the wellhead is located more than one quarter of a mile from the associated well production facility for well production facilities commencing operations on or after May 1, 2021, or for wellheads not located on the same surface disturbance for well production facilities commencing operations prior to May 1, 2021. Any other pneumatic controllers (e.g. those not used as emergency shutdown devices or for artificial lift control) located at the wellheads within the specified distance from the associated production facilities must be non-emitting, unless the operator submits a justification for use of an emitting controller to the Division for approval at least 45 days prior to installation of the emitting device or retrofit of the facility or by July 1, 2021 for well production facilities that commenced operations prior to May 1, 2021 and the operator intends to be reflected as non-emitting in the company-wide plan.

The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities commencing operation or taking actions described in Section III.C.4.a.(ii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(D)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Section III.C.4.a.(ii) occur. The one quarter mile measurement associated with distance from the wellhead to the well production facility shall be measured from the wellhead to the closest equipment associated with the well production facility.

To qualify for the exemption in Section III.C.4.e.(i)(D), the operator must use an approved instrument monitoring method and AVO to detect leaks at the wellhead at the same frequency as the associated well production facility as set forth in Table 3 of Section II.E.4, which sets forth the frequency of component inspections, or no less than once per year, whichever is greater. For facilities that commenced operations prior to May 1, 2021, this monitoring requirement will begin on May 1, 2022, or the date the facility is converted to a site with only non-emitting controllers, whichever is later. The Commission recognizes that wellheads may sometimes be difficult to inspect due to land access issues or severe weather and has adopted provisions allowing operators to delay inspections until access is restored. Owners or operators also may utilize OGI camera-equipped aerial drones to perform these wellhead inspections to provide frequent leak detection and further promote the advancement of leak detection methodologies - both of which are foundational to Colorado's find and fix approach to leak detection. At the same time, the Commission believes this application of OGI requires rethinking of the methodology generally used for land based OGI applications.

Thus, the provisions of Section III.C.4.e.(i)(D)(3) allowing for the use of OGI camera-equipped aerial drones to inspect wellhead equipment apply on a limited basis, as state-only provisions and do not by themselves authorize the use of drones to inspect other equipment or constitute approval of drones as alternative AIMM. Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request. The methodology must include, at a minimum, procedures for: determining maximum wind speed during which the inspection can be performed; determining the maximum viewing distance from the equipment; how the operator will ensure an adequate thermal background is present to view potential leaks; how the operator will deal with adverse monitoring conditions, such as wind; and how the operator will deal with interferences. At a minimum, any drone inspection must ensure line of sight from the drone to all wellhead equipment and components and take place when the drone-mounted camera is close enough to the wellhead equipment and components to achieve sensitivity for detection of emissions similar to the sensitivity commonly achieved during OGI inspections carried out with hand-carried infrared cameras. Furthermore, the Commission directs the parties to this rulemaking that wish to participate to jointly recommend an OGI camera-equipped aerial drone usage methodology to the Division's Alternative AIMM Team by May 2022, for further review and consideration.

Finally, operators may not use this exemption where equipment with natural gas emitting pneumatic controllers other than the wellhead, such as a separator, is located at the wellhead site. Under those circumstances, emitting pneumatic controllers used for emergency shut down control may still qualify for the safety and process exemption under Section III.C.4.e.(i)(A) where the necessary conditions and approvals for that exemption are met.

Tagging of Controllers

In order to assist in ease of identification of pneumatic controllers that are authorized to emit natural gas to the atmosphere, the Commission has required operators to tag pneumatic controllers that are authorized to emit natural gas to the atmosphere pursuant to the specified exemptions in Section III.C.4.e.(i) at wellhead production facilities which are non-emitting and at natural gas compressor stations that have one or more non-emitting controllers. Natural gas compressor station operators must differentiate between emitting pneumatic controllers that are exempt under Section III.C.4.e.(i) and those that are not identified as non-emitting controllers in the company-wide plan and are, thus, not required to retrofit. The requirement to tag pneumatic controllers that emit natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) does not apply at well production facilities that are not required to be non-emitting or elected to be non-emitting pursuant to the company-wide plan requirements. In each instance where the regulation references a requirement to use non-emitting controllers, such reference is limited by the exemptions allowing the use of pneumatic controllers to emit natural gas to atmosphere as set forth in the regulation.

Recordkeeping

Operators of well production facilities or natural gas compressor stations must keep the following records for five years, and make them available to the Division upon request: (1) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date the natural gas compressor station pneumatic controllers were retrofit or it is taken out of service, (2) If claiming an exemption for an emitting pneumatic controller, records for each controller demonstrating the exemption applies, (3) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans, (4) For any operator utilizing III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies under that provision, and (5) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time, other than those revising definitions currently in the SIP.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7- 110.5(5)(b), CRS, the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including natural gas-driven pneumatic controllers. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more natural gas-driven pneumatic controllers than the NSPS.

(II) The Federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations.

(III) The revisions to Regulation Number 7 strengthen Colorado's state-only provisions. These revisions currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(IV) The revisions to Regulation Number 7, Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(V) Where necessary, the revisions to Regulation Number 7 include monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(VI) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for pneumatic controllers.

(VII) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(VIII) Alternative rules could also provide reductions in ozone, VOC, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19- 181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements related to pneumatic devices. The Commission determined that the alternate proposal was reasonable and cost-effective.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

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

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

(II) Evidence in the record support the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

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

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

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

W. July 16, 2021 (Part C, Section I., Part D, Section III., Part E, Section II.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

<u>Basis</u>

On December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. Currently, the DMNFR is also designated as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

To ensure progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to include reasonably available control requirements (RACT) for process heaters at major sources of NOx emissions and metal parts surface coating.

<u>Statutory Authority</u>

The State Air Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a) and (2) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources and emission control regulations pertaining to nitrogen oxides and hydrocarbons.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rationale for the adoption of the revisions. The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for process heaters at major sources of NOx emissions and metal parts surface coating. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Metal parts coating

The Commission has previously adopted requirements for metal surface coating based on recommendations in EPA's Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VI: Surface Coating of Miscellaneous Metal Parts and Products (1978), including VOC content limits, work practices, and recordkeeping requirements. However, EPA published a subsequent metal coating CTG, Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings (Metal Coating CTG), in 2008 that recommends expanding the coatings VOC content limits from four to fifty, including work practices, application methods, and recordkeeping. Therefore, in response to EPA's concern with Colorado's existing metal parts coating requirements as based on EPA's 1978 CTG, the Commission revised the metal surface coating requirements to correspond to the recommendations in the 2008 Metal Coating CTG.

Pneumatic controllers

In February 2021, the Commission adopted a consensus alternate proposal to reduce emissions from existing pneumatic controllers at well production facilities and natural gas compressor stations, in addition to the proposed emission reductions from pneumatic controllers at new and modified facilities. The Commission now adopts a revision correcting an inadvertent incorrect citation.

Major source RACT

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the Clean Air Act's (CAA) Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR. Therefore, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for process heaters at major sources of NOx emissions, specifically NOx emission limits for natural gas-fired and refinery gas-fired process heaters with a heat input rate greater than or equal to 5 MMBtu/hr.

The Commission also adopted performance testing requirements, and associated recordkeeping, for natural gas-fired and refinery gas-fired process heaters greater than or equal to 100 MMBtu/hr and natural gas-fired process heaters greater than or equal to 50 MMBtu/hr but less than 100 MMBtu/hr. The owners or operators must comply with the applicable NOx emission limits by May 1, 2022, except where the process heater requires a permitting action or facility shut-down, in which case owners or operators must comply by May 31, 2023. The May 31, 2023, later compliance deadline for facility shut-downs is intended to provide additional time where a substantial shutdown is required to comply with the NOx limits in Table 2, even if the entire plant is not shut down. The owners or operators of subject process heaters will continue to comply with the combustion process adjustment and associated recordkeeping requirements. The Commission also expanded these provisions to process heaters at sources that emit, or have the potential to emit, 25 tpy NOx, in anticipation of a reclassification to Severe nonattainment. While expanding these requirements to 25 tpy sources in advance of the reclassification differs from the past timing approaches for including RACT for major sources, this expansion is limited in scope (i.e., process heaters) and the Commission does not anticipate expanding SIP RACT requirements in advance of a reclassification to become a regular practice.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone serious nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations. These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), CRS, the Commission determines:

(I) The revisions to Regulation Number 7 address process heaters operated by refineries and the oil and gas sector. NSPS J, NSPS Ja, NSPS XX, MACT CC, and MACT UUU may also apply to petroleum refinery equipment and operations. However, the revisions to Regulation Number 7 apply on a broader basis to more process heaters.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply.

(III) The CAA establishes the 2008 NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's ozone nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established Colorado's SIP-RACT implementation deadlines. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 strengthen Colorado's SIP. These sections currently address emissions from process heaters and metal parts coating in a cost-effective manner, allowing for continued growth of Colorado's industry.

(VII) The revisions to Regulation Number 7, Parts C and E establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for metal parts coating. The revisions concerning major sources of NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, and NOx to help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the ozone nonattainment area requirements. However, to the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of VOCs and NOx 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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

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

X. December 17, 2021 (Revisions to Part D, Sections I., 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.

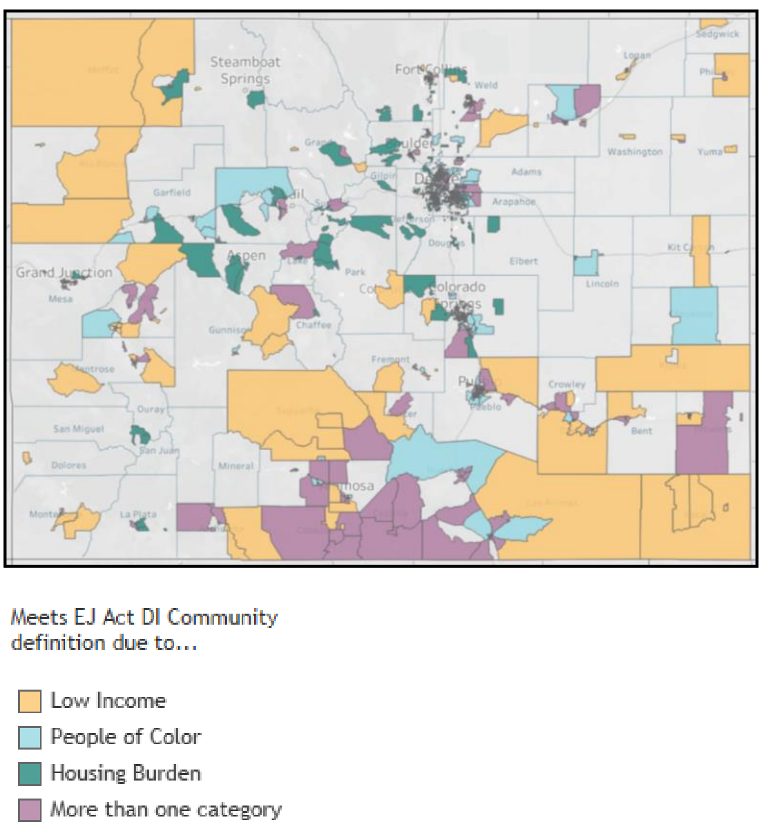
Basis

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 oil and gas 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 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. § 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. § 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. § 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.

§ 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. § 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.

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.

SIP revisions to address the Oil and Gas CTG: Section I.

As a moderate ozone nonattainment area, Colorado was required to revise its State Implementation Plan (SIP) to address Clean Air Act (CAA) moderate ozone nonattainment area requirements as forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone National Ambient Air Quality Standard (NAAQS) (See 80 Fed. Reg. 12264 (March 6, 2015)), including revising its SIP to include reasonably available control technology (RACT) requirements for each category of volatile organic compound (VOC) sources covered by a Control Technique Guideline (CTG) for which Colorado had sources in the Denver Metro North Front Range (DMNFR) ozone nonattainment area. EPA finalized the Oil and Gas Control Techniques Guidelines (Oil and Gas CTG) on October 27, 2016. In a 2017 rulemaking, the Commission carefully considered what recommended provisions to include in Colorado’s SIP. The Commission considered its discretion in adopting recommendations in a CTG, and Colorado’s already existing emission control requirements that addressed most of the same sources covered by EPA’s Oil and Gas CTG but were not identical to the recommendations in the Oil and Gas CTG. The Commission submitted SIP revisions addressing the Oil and Gas CTG to EPA in May 2018.

In June 2021, EPA proposed to approve these SIP revisions (see 86 Fed. Reg. 32656). However, in September 2021, as a result of public comments received on the proposed approval, EPA requested that Colorado strengthen associated monitoring requirements for combustion devices controlling storage vessels and wet seal centrifugal compressors. In this action, the Commission adopted targeted revisions to Section I. to further align with EPA's Oil and Gas CTG. Specifically, the Commission adopted performance testing, or demonstration of manufacturer testing, for combustion equipment used to control emissions from storage vessels, as defined in EPA's Oil and Gas CTG, and wet seal centrifugal compressors.

The Commission adopted language corresponding to the recommendations in the EPA's Oil and Gas CTG and provides the following clarifications as related to purpose, intent, and terminology. Concerning the purpose of the performance test, EPA's Oil and Gas CTG recommends the performance test to demonstrate compliance with the recommended level of control, which is a 95% reduction of VOC emissions from storage vessels and a 95% reduction of VOC emissions from centrifugal compressor wet seal fluid degassing systems. As EPA discusses in the Oil and Gas CTG, if an owner or operator complies with the recommended RACT by using a combustion device, initial and periodic performance testing of the device is recommended. The performance test will demonstrate that the combustion device reduces the mass content of VOC in the gases vented to the device by at least 95% by weight.

Concerning the terms “potential for VOC emissions” and “(controlled actual emissions)” in the storage vessel applicability provision, the Commission adopted language corresponding to the recommended applicability provision in EPA's Oil and Gas CTG, which is based on EPA's NSPS OOOO and OOOOa. The Commission included the phrase “(controlled actual emissions)” in recognition of more extensive storage tank control requirements in Section I., as related to the recommendations in EPA's Oil and Gas CTG for storage vessels, and not to allow and operator to use a different calculation methodology than that used to determine the storage vessel's potential for VOC emissions. The Commission intends for the Division to determine whether storage vessels are subject to the performance testing requirement adopted in this December 2021 rulemaking, in the same manner the Division currently determines whether a storage vessel is subject to NSPS OOOO, including averaging emissions across the number of storage vessels in the battery as included in EPA's NSPS.

Concerning “generally accepted model or calculation methodology,” “30-day period of production,” and “legally and practically enforceable limit,” the Commission also intends these phrases to be applied as the Division already applies them for NSPS OOOO. The Commission recognizes that the Division provides guidance on acceptable calculation methods and has issued guidance, “Interpretation of “Practically Enforceable” Limits for Storage Vessels Addressed under NSPS OOOO” (Oct. 15, 2013), clarifying where operators may take credit for permit required controls. The Commission intends for the Division to apply the applicability provision in Section I.E.3.a., which is the CTG recommended applicability and based on EPA's NSPS OOOO and OOOOa, as the Division currently applies such applicability provisions under NSPS OOOO.

<u>Definitions: Section II.A.</u>

The Commission has adopted definitions for new terms to facilitate implementation of the new regulatory programs. 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 intended to define “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. The Commission has included, in the definition of this term, a reference to the climate equity data map at which more detail can be seen of the boundaries of the disproportionately impacted communities addressed by this rulemaking. The Commission has also referenced a list of the census block groups by 12-digit FIPS code covered by the map incorporated into the definition, identifying what census blocks are disproportionately impacted communities as of the date of this rulemaking. The Commission intends that the Division will preserve a copy of the map and the accompanying list in place at the time of this rulemaking such that sources may use the map and list as a guide for understanding the applicability of requirements.

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 enclosed combustion equipment (or a bank of enclosed combustion devices) used as 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, comparing flow rates against the high end flow limitations of the enclosed combustion device used to ensure that the enclosed combustion device is being operated within the design parameters. 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 (or other Division-approved parameter) to air pollution control equipment for those situations in which flow meters are less effective or accurate. Where an operator has submitted a plan for the use of an alternate parameter under Section II.B.2.g.(iii)(C), the Commission directs the Division to promptly review and approve or deny appropriate alternative monitoring mechanisms or parameters to ensure operators may meet the applicable deadlines in Section II.B.2. However, the burden remains on the operator to comply with the regulation or, where approved, the provisions of the alternative approval. The Commission intends that if the flow meter is not connected to automation to continuously record flow, it should be capable of storing at least two weeks of data.

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 emitted from equipment controlled in accordance with requirements in Regulation Number 7, Part D, Sections I.D., II.C.1., II.D., or II.F. (Note: this requirement is not intended to include performance testing for combustion of pilot light gas only.) In Section II.B.2.h.(i)(H), the Commission does not require retesting if an enclosed combustion device is replaced with a newly manufactured enclosed combustion device. However, the Commission intends that this apply only where the issue causing the failing test would be addressed by replacement of the device itself, and the failing test was not due to some other cause.

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 enclosed combustion devices 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 SIP, 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, and corresponding improvement in performance, of higher capacity or older enclosed combustion devices, especially those in disproportionately impacted 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 disproportionately impacted 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 and directs the Division to consider publishing that protocol on its website as a pre-approved test protocol for enclosed combustion device 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. Given the evolving and innovative work and study in this area to evaluate the performance of enclosed combustion devices, the Commission recognizes that protocols may be developed, subject to Division approval, that don't result in a strictly numeric destruction efficiency evaluation, such as a traditional stack test, and those may be approvable protocols, in which case, the protocol will identify the metric by which the testing will be considered passing or failing.

The Commission understands that development of performance testing protocols is important to meeting the performance testing deadlines and directs the Division to develop, by August 1, 2022, a standard protocol framework for performance testing to allow operators to meet the required testing timelines, and by October 31, 2022, an alternative protocol to a traditional stack test for low-flow ECDs where appropriate. The Commission further directs the Division to review proposed companywide performance testing protocols within six months of receipt of the proposal or, where approval or denial cannot be accomplished in that time frame and where the protocol was submitted with adequate time to implement testing after Division approval, to consider approving alternative testing schedules. However, the inability of the Division to develop standard protocols or to approve a performance test protocol within the time frames provided does not relieve the operator of the duty to comply with this regulation.

Performance testing requirements under Regulation Number 7 do not limit the division's authority to otherwise require performance tests under Common Provisions, Section II.C. including those required as the outcome of approving a construction permit.

Section II.B.2.h.(i)(D) sets forth requirements for flow meter installation for each enclosed combustion device subject to Section II.B.2.h. Flow meters are necessary for certain performance test methodologies, specifically for inlet and outlet testing protocols. Therefore, while permanent flow meters are required for individual or banks of enclosed combustion devices under Section II.B.2.g., a temporary or permanent flow meter must be installed for the time period of performance testing on each individual enclosed combustion device. Where the Division approves an alternate protocol or methodology that doesn't require a flow meter for accurate determination of control efficiency, owners or operators will not need to install a flow meter in accordance with this requirement.

In Section II.B.2.h.(i)(E), 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, the enclosed combustion device fails the test, a retest is conducted on July 1, and the enclosed combustion device passes the retest, the operator should use the results of the failing performance test for emission calculations from January 1 through June 30, and may use the results of the passing performance test from July 1 through December 31 of that year.

In Sections II.B.2.i and II.B.2.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 enclosed combustion device 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 thirty (30) days of a failing test. The Commission intends that for reporting under Section II.B.2.j.(i), owners or operators will submit with the notice of the failing test the monthly emissions of methane and VOC and monthly throughput (production or throughput of either natural gas or oil to the equipment being controlled) back to the beginning of the calendar year of the failed test. The Commission intends that operators will still comply with the Division's Compliance Test Protocol.

The Commission directs the Division to gather additional information about ECDs to better understand the life cycle of the devices. For example: the degradation of the devices over time, appropriate testing schedules, efficiency over time, and characteristics of the failure rate. The Commission also requests that the Division report back to the Commission with this information within 24 months.

<u>Rod packing at natural gas processing plants: Section II.B.3.</u>

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 New Source Performance Standard (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.

Owners or operators are required to change reciprocating compressor rod packing on or before 26,000 hours of operation. Owners or operators may elect to change the rod packing every 36 months instead of monitoring compressor operating hours. However, the owner or operator must begin measuring hours or months on February 14, 2022, and then change the rod packing on the applicable schedule of the parameter the owner or operator elects to measure. While this provision builds upon current reciprocating compressor rod packing requirements where this schedule was understood, the Commission now clarifies that owners or operators must utilize one measurement parameter per rod packing replacement cycle.

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.

<u>Leak Detection and Repair: Sections II.E. and II.I.</u>

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 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 statewide, in proximity to occupied areas, and in disproportionately impacted communities (see map 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 also increased inspection frequencies for most well production facilities with emissions below 50 tpy (or below 20 tpy for tankless facilities) and created a new Table 5 which will inform required LDAR frequencies beginning January 1, 2023. The new table includes increased inspection frequencies at well production facilities in disproportionately impacted communities and within 1,000 feet of occupied areas.

The Commission does want to encourage the use of alternative design techniques and 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 also requests that the Division work with stakeholders and parties to this rule in 2022 to consider the opportunities to employ advanced screening and/or continuous monitoring as alternative AIMM.

The Commission has also recognized two scenarios where well production facilities need not conduct AIMM inspections in accordance with the newly increased frequencies. 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 constructs a tankless well production facility (i.e., no hydrocarbon liquid storage tanks except for a maintenance or surge tank) with automation to provide operational feedback, non-emitting pneumatic devices, and without gas-fired engines for compression or primary power generation. For the first scenario, 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. In the second scenario, AIMM inspections must be completed on a semi-annual basis. For both scenarios, if an operator were to cease using any of these scenarios, the facility would immediately revert to a monthly AIMM schedule or schedule based upon Table 5, as applicable.

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.

In Sections II.E.7.a.(iv) and II.I.1.b., the Commission considered requirements for leaking equipment and components that are placed on delay of repair and, specifically, required operators to mitigate emissions from leaking components on delay of repair and document the efforts. At natural gas processing plants, the Commission would like to encourage operators to consider drill and tap as a method of fixing component leaks while reducing equipment blowdowns, where feasible. The Commission also understands that low-e valves are cost effective and beneficial in reducing fugitive emissions from components and recommends that operators consider low-e valves as they replace and repair leaking equipment and construct new facilities.

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 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 Section 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.1.c. 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. As another 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.

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. The Commission has established thresholds at which well liquids unloading activities must be controlled. These capture or control requirements apply as of January 1, 2023; however, the Commission does not intend that the "counting" of unloads will begin on January 1, 2023. Instead, for determining whether control is required as of January 1, 2023, the operator must look back over the preceding 12 months - i.e. calendar year 2022 - to consider if any of the thresholds are met.

The regulation speaks to well production facilities that "have" wells with specified numbers of unloading events. The regulation includes all wells producing into that well production facility - the wellhead itself need not be physically located within the boundaries of the well production facility. Most of the thresholds speak to well production facilities where operators conduct a specified number of unloading events - unless explicitly otherwise stated, the Commission intends this to account for unloading events from all wells producing into that facility. For example, under Section II.G.1.d.(ii)(A), capture or control is required if the number of unloading events at the well production facility totals six or more; at a well production facility with 3 wells, this threshold is reached where each well is unloaded to the atmosphere twice in that six-month period.

The Commission's existing regulation in Section II.G.2.b. requires operators to maintain, among other things, the date, time, and duration of unloading events resulting in emissions to the atmosphere. The Commission intends that the failure to keep required records leads to a presumption that control would have been required for such events.

The Commission understands that, infrequently, a nearby hydraulic fracturing event (i.e., an “offset frac”) can cause a well to fill up with water, necessitating the unloading of that well to remove the water. The Commission believes that such unloading events - so long as they are limited in scope and duration - should not be counted toward the applicability thresholds of this rule, which is directed at wells that can be expected to have routine or predictable unloading operations (with emissions to atmosphere). The timing of the notice of the offset frac in Section II.G.1.d.(iii) is intended to be consistent with the COGCC rule addressing the same notification. The Commission intends that if the Division later determines the claim of offset frac was not valid for a particular event or series of events, the operator bears the risk of not having employed capture or control techniques. Further, the Commission emphasizes that it expects this to be a "limited-use" exemption, subject to removal from the rule if overused.

For recordkeeping and reporting purposes, the Commission intends that operators directly measure the volume of gas emitted during liquids unloading events and report that information to the Division annually. The Commission included this measurement and reporting requirement due to the uncertainty regarding the reliability of estimated volumes reported to EPA under GHGRP and reported to the Division under Regulation Number 7 annual emission reporting. However, the Commission encourages the Division to work with operators on using direct measurement of volumes vented during unloading to, as appropriate, develop updated calculation methodologies or emission factors to use in reporting emissions from well liquids unloading.

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 or blowing down compressors and other equipment in natural gas gathering operations can emit VOCs. Emissions associated with the removal of oxygen from equipment to place equipment into service after a blowdown are not subject to Section II.H. in order to safely operate the equipment. This gas released from pigging and blowdown 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 owners or operators capture and recover gas from pigging and blowdown 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 Commission has a strong preference for capture and recovery established in this regulation, but does allow for control or use of a closed vent system. The Commission intends that the reference to closed vent system here is consistent with the requirements of Part D, Section I. and NSPS OOOOa, 40 CFR 60.481a.

The Commission adopted requirements to require capture or control of emissions from pigging operations in all cases where the pigging unit is attached to a pigging pipeline with an outside diameter of 12 inches or more and with a normal operating pressure greater than or equal to 500 psig. The Commission defined normal operating pressure by reference to the annual average operating pressure. However, if an operator makes an engineering adjustment to the pigging pipeline that lowers the operating pressure to below the 500 psig threshold (assuming that this engineering adjustment is not truly temporary in nature), the Commission does not intend that the operator has to wait a year for the annual average operating pressure to drop before falling out of applicability. Additional requirements to capture or control are dependent on emission thresholds of both VOC and methane, and the thresholds are the most stringent in disproportionately impacted communities. The Commission included thresholds for both constituents because of the difference in gas composition between the front range and the rest of the state. The Commission is establishing the specific thresholds and performance standards on pigging units and blowdowns in the midstream sector based on specific operational and emissions data associated with the midstream segment in Colorado.

Further, the Commission is requiring capture or control of emissions from pigging operations that commence operation after the effective date of this rule, where the pigging unit is attached to a high-pressure pipeline (regardless of diameter) and at certain specified emission thresholds. In addition, to encourage innovative engineering of and practices at future natural gas compressor stations, natural gas processing plants, and standalone pigging stations, the Commission adopted Section II.H.1.d., which requires an operator to analyze and implement engineering technologies and capabilities and operational practices that maximize the capture and recovery of hydrocarbon emissions from pigging operations and other equipment and piping that are routinely blown down. The Commission intends that this analysis be undertaken at the time of initial facility design and development. Similarly, to minimize emissions associated with the equipment necessary to power the capture and control equipment, the Commission adopted Section II.H.3.b. This section provides that where a natural gas compressor station or natural gas processing plant is connected to the electrical grid, the operator should use that electric grid as the source of power for the equipment required for capture and recovery techniques, where technically and economically feasible.

The Commission intends that this analysis be undertaken at the time the pigging unit or piping and equipment must comply with Section II.H., whether by January 1, 2023, or sometime after that initial compliance date. For example, if an operator adds a pigging unit in 2024, and the operator intends to use gas recovery equipment to capture the emissions, the operator must conduct an evaluation of whether it is technically and economically feasible to power that gas recovery equipment through grid power. In order to demonstrate compliance with Sections II.H.1.d. and II.H.3.b., the operator must retain the record of that determination and the basis therefor. Under both these provisions, it is not the Commission's intent that the Division second-guess the reasonable engineering, design, and business judgment of the operator. The Commission recognizes that these analyses may contain confidential business information.

In Sections II.H.1.a.(iii) and II.H.1.a.(iv), the Commission understands that capturing or controlling emissions from small blowdown events, either from compressors or other equipment, is often cost prohibitive (when looked at on a per-blowdown or per-equipment basis) and may result in more emissions from the capture and control efforts than what is reduced based upon the fuel source for the capture or recovery equipment. Therefore, the Commission has included that blowdown events from compressors or equipment, where between isolation valves the total volume is less than 50 cubic feet, do not need to be included in emission calculations toward the thresholds nor do they need to be captured or controlled. However, the Commission feels it is important to better understand the frequency and number of such events. If an owner or operator is found not to be keeping the required records relating to blowdown events greater than 1 cubic foot and under 50 cubic feet, the regulatory presumption is that capture or control was required for equipment blowdown events, and noncompliance is not a simple recordkeeping violation.

Further, in Sections II.H.1.c.(vii) and II.H.1.c.(viii), the Commission provided that when a source previously not subject to capture or control has emissions that meet or exceed the applicability thresholds, that source will have sixty (60) days from the first day of the month after meeting/exceeding the thresholds to comply with the capture or control requirements. The Commission believes that operators should be tracking emissions such that they can generally predict when a source will exceed thresholds and should prepare accordingly. However, the Commission understands that sometimes unforeseeable events will cause an emissions increase. Under such circumstances, the Commission encourages operators to reach out to the Division prior to missing a compliance deadline, and directs the Division to work with those operators to ensure capture and recovery begins as soon as practicable, which may be more than 60 days.

The Commission also provided, in Sections II.H.3.e and II.H.3.f, that capture and recovery is not always required. Capture and recovery is only required during normal operations - i.e. not during malfunctions. And capture and recovery is not required during emergency shutdown systems testing, such as would be required under OSHA's Process Safety Management standard. Further, in Section II.H.3.g, the Commission provided that capture or recovery is not required on certain vessels; however, uncontrolled actual emissions from blowdowns of these vessels (if greater than 50 cf) must be included in the calculations for purposes of the general applicability of control requirements. Operators must look at uncontrolled actual emissions from blowdowns - if a piece of equipment is blown down and the emissions are controlled, the uncontrolled actual emissions from that blowdown event still count toward the applicability threshold. The Commission does not intend that its requirements for capture and control place operators in a situation to choose between compliance with this program and compliance with federal regulatory programs for leak detection. Thus, to the extent there are limited situations where an operator cannot reasonably capture or control the blowdown emissions necessary to fix a leak within the timelines required by federal programs, and under those same federal programs would be prohibited from placing that leak on delay of repair, operators must keep records of these events, and include information about these events on the annual emission reports submitted pursuant to Section V. Under these limited circumstances, compliance with the federal rules will generally not be deemed non-compliance with Section II.H. The Commission further directs the Division to consider whether future revisions to this program are necessary to address this type of conflict or others that may arise in the implementation.

The Commission, in addition to the capture and control requirements for pigging and blowdowns, also requires the use of certain best practices to reduce either the need or frequency of pigging and blowdown events or reduce the emissions from those activities. The Commission understands that not all best practices are viable for every location, however, and so in Section II.H.4.c., the Commission requires certain best practices to be used unless not feasible. For economic feasibility, operators bear the burden of demonstrating to the Division, upon request, that a particular decision not to use this best practice was not economically feasible, including providing specifics as to the costs used in the evaluation. Such costs do not appropriately include all indirect costs, such as internal overhead or administrative costs.

The Commission mandated recordkeeping and reporting requirements in Sections II.H.6. and V. applicable to pigging operations and blowdown activities to ensure compliance with and to track the efficacy of the established emission reduction measures. Emissions from pigging and blowdowns must be separately included in Regulation Number 7, Part D, Section V. annual reports. The records for pigging activities must include the total number of pigging events, even if not subject to capture or control.

The records must outline the location, date, time, and duration of the blowdown emissions, including records of the date, location, and equipment for which there are blowdown events where the volume between isolation valves is less than 50 cubic feet (but greater than 1 cubic foot for piping and equipment). Where Section II.H.5.b.(i) requires recordkeeping of the pressure of the pigging unit before and after capture and recovery (if applicable) and immediately before emissions to the atmosphere, the Commission is seeking information regarding the volume of gas emitted. Therefore, where capture and recovery techniques are employed, the Commission is seeking the starting pressure of the pigging unit prior to capture and recovery and the pressure of the pigging unit after capture and recovery but before the emission of the residual gas. As an example, if the pigging unit is at 900 psig before sending the gas to a low-pressure line by jumper line and at 50 psig where the remaining residual volume of gas is emitted to atmosphere, the operator would report a starting pressure of 900 psig and an ending pressure of 50 psig. Then, the emissions from the release to atmosphere of the remaining 50 psig down to 0 psig would be recorded as actual emissions as required by Sections II.H.5.b.(ii) and V. Where no capture and recovery techniques are employed, the Commission understands that the ending pressure will always be 0 psig.

The Commission also updated Sections 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.

<u>Pneumatic Controller Revisions: Section III.</u>

The Commission also expanded the applicability of natural gas-fired pneumatic 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 non-emitting pneumatic 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).

In Section III.F., the Commission aligned the inspection schedules for natural gas-driven pneumatic controllers with the revised inspection schedules for components in Section II.E.

<u>Annual Emissions Reporting: Section V.</u>

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 recognizes that some equipment is reported to EPA in the aggregate, while reported individually to the Division. The Commission intends that the operator provide sufficient information to enable the Division and the public to understand the differences in an operator's calculation methods; the Commission does not hereby require that operators educate the Division or the public on the differences between the federal and state reporting programs. 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. The Commission directs the Division to work with operators to conduct representative sampling, where appropriate. The Commission has set the frequency for sampling at five years, which aligns with APEN update frequencies. The Commission does not intend that operators can wait five years to conduct their first gas composition analysis; in adopting a schedule that aligns with APEN updates, the Commission intends to generally align the sampling schedule with APEN updates.

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 1 cubic foot. The Commission notes its interpretation that the 50 cubic foot exemption adopted in 2019 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 less 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 1 cubic foot can be difficult. Therefore, the Commission directs the Division to accept appropriate actual and approximated reported volumes for this subcategory of blowdowns. For the revised exemption of blowdowns where the physical volume is less than 1 cubic foot, the Commission requires operators to maintain a list of the equipment and blowdown activities that have volumes less than 1 cubic foot so that the Division can maintain oversight of those blowdowns and revisit the availability of this more limited exemption as appropriate.

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.

Annual Information Reporting: Section V.D.

In 2020, the Colorado Oil and Gas Conservation Commission adopted COGCC Rule 904(a), which was designed to facilitate information sharing between the COGCC and CDPHE. COGCC Rule 904(a) mandates an annual report by the COGCC Director to the COGCC, and expresses an intent that the COGCC Director collaborate with the Division to include certain specified information. Stakeholders requested that this Commission adopt a counterpart to that rule, to ensure that the information necessary to that COGCC Rule 904 report is timely provided. The Commission agrees and has adopted Section V.D. to facilitate that information sharing by the Division. The Commission has specified that several annual reports already required to be presented to this Commission will be provided thereafter to the COGCC, including the annual ozone report and the annual GHG Roadmap progress report (and the more formal biennial GHG Roadmap inventory update and progress report).

The Commission encourages meaningful and frequent collaboration between the Division and the COGCC, to ensure that the state can meet its air quality goals, including reducing greenhouse gas emissions, striving towards ozone attainment, and reducing “cumulative impacts” of oil and gas development. The Commission anticipates the agencies sharing information regarding evolving or new innovative technologies or measures that may provide innovative methods to reduce emissions; identifying areas for further study; and annual reporting to both this Commission and the COGCC will ensure that collaboration is ongoing and effective.

<u>Miscellaneous</u>

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.

The Commission directs the Division to consider extending the schedule for the company-wide non-emitting controller program, and to consider additional requirements to retrofit pneumatic controllers at sites not currently subject to retrofit pursuant to Section III.C.4.c.(iv), coincident with the oil and gas section rulemaking planned for the first half of 2023.

<u>Incorporation by Reference</u>

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

<u>Additional Considerations</u>

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

As some of these revisions exceed and may differ from the federal rules under the federal act, in accordance with § 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 additional proposals to address greenhouse gas emissions from oil and gas equipment, but EPA's proposal will not address the particular situations addressed by the Commission's revisions here.

CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission in 2017. The revisions adopted by the Commission in this rulemaking strengthen the previously adopted requirements and are comparable to the Oil and Gas CTG's recommendations.

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 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. These revisions 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 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.

The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. Neither the ozone NAAQS nor EPA's Oil and Gas CTG addressed concerns unique to Colorado.

(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.

The SIP revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommendations in its Oil and Gas CTG as RACT.

(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.

EPA is under a mandated deadline to act on Colorado's SIP revisions as related to EPA's Oil and Gas CTG and has requested that Colorado expeditiously adopt the SIP revisions included in this rulemaking in order to complete that approval action.

(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.

Further, if EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan, thus potentially determining RACT for Colorado's sources and subjecting others to increased costs.

(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 § 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, 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, 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. In addition, the CAA requires that Colorado’s Ozone SIP must include RACT requirements for each category of VOC sources covered by a CTG. EPA requested that Colorado strengthen associated monitoring requirements for combustion devices controlling certain equipment to further align with EPA’s Oil and Gas CTG. Based on conversations with EPA, the revisions further align Colorado’s Ozone SIP RACT requirements with the recommendations in EPA’s Oil and Gas CTG. Alternative rules may not align with the recommendations in the Oil and Gas CTG, thereby failing to qualify as necessary SIP RACT resulting in an unapprovable SIP. Because EPA has requested these changes be made expeditiously, a no-action alternative would likely result in an unapprovable SIP. The Commission determined that the Division’s proposal was reasonable.

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 alternative 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.

Y. December 17, 2021 (Removed from Regulation Number 22 and placed in Regulation Number 7 April 20, 2023)

Revisions to Regulation Number 22, Part B, Sections III. and IV.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-101, C.R.S., et seq., the Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 C.C.R. §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 (OGCC) and this Commission. In the same session, the General Assembly adopted House Bill 19-1261 (HB 19-1261), setting statewide greenhouse gas (GHG) reduction goals. The General Assembly declared in 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.

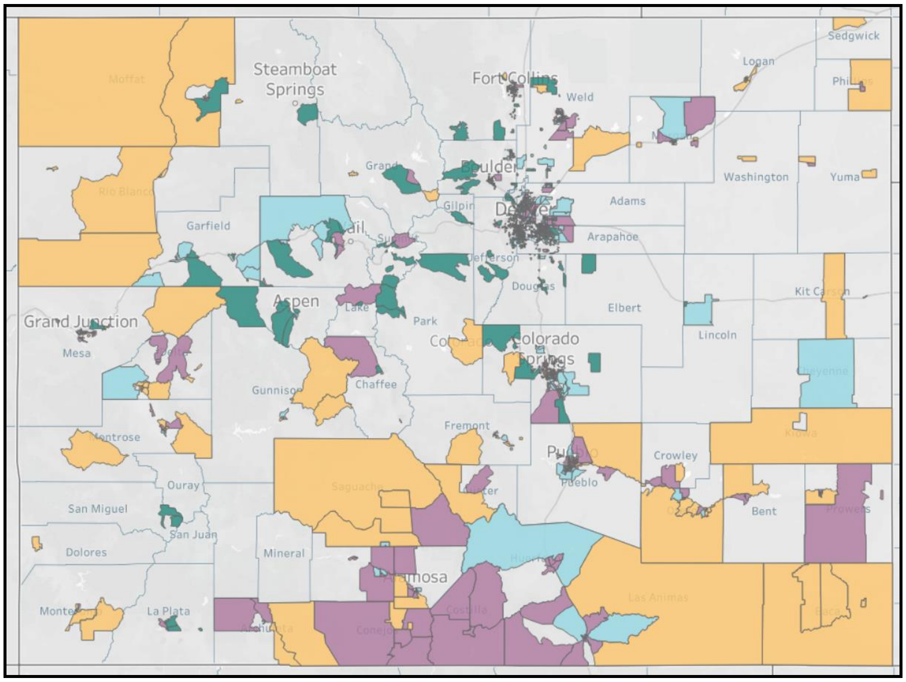
The goals set in HB 19-1261 seek a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels. The GHG Pollution Reduction Roadmap ("GHG Roadmap") developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the baselines from which these reduction percentages are to be estimated.

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) CO_2e by 2025 and 8 MMT CO_2e by 2030). Commission targets for the sector including industrial combustion emissions (Industrial Sector) include a 20% reduction from 2015 numbers by 2030. House Bill 21-1266 (HB 21-1266), signed into law on July 2, 2021, memorializes these percentage reductions in statute, and provides additional requirements for the rulemakings to achieve these goals.

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. Most 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, the emissions from fuel combustion at oil and gas sources in the upstream and midstream segments are largely found in the "RCI Sector" of the GHG Roadmap (specifically in the "industrial" category, which is the subject of specific requirements in 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. In this action, 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. Senate Bill 21-264 (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 also 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 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:



Meets EJ Act DI Community definition due to…

- Low Income
- People of Color
- Housing Burden
- More than one category

<u>Specific Statutory Authority</u>

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 provides the Commission broad authority to regulate air pollutants, including GHG and its constituent gasses (particularly carbon dioxide, methane, and nitrous oxide).

§ 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. § 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. § 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. § 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 in the GHG Roadmap (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 ensure that the state meets its statutory goals. These revisions to Regulation Number 22 will, taking into account other relevant laws and rules (including the revisions to Regulation Number 7 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.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 22, and includes the technological and scientific rationale for the adoption of the revisions. The Commission recognizes that a task force on Carbon Capture, Utilization, and Storage (CCUS) has been convened as part of the GHG Roadmap implementation, with a report to the Governor due in January 2022. The Roadmap recognizes CCUS may play an important role over a longer time horizon in meeting the HB 19-1261 targets, but that uncertainties make modeling CCUS contributions difficult at this time. The Commission encourages the Division to evaluate ways to incorporate GHG emission reductions generated from CCUS projects into existing or contemplated regulatory programs such as the fuel combustion program or the GHG intensity program discussed.

Definitions: Sections III.A. and IV.A.

In Sections III.A. and IV.A., the Commission included several defined terms from Regulation Number 7 and intends that the same terms have the same meaning in both regulations unless otherwise specified (i.e., unless the regulation states that a term is defined specifically for purposes of that regulation). The Commission intends that terms used in Sections III. or IV., even if only defined in one of those Sections, have the same meaning.

The Commission defined both the midstream segment and the upstream segment of the oil and gas industry. The upstream segment is not intended to necessarily be co-extensive with the use of the term "exploration and production operations" in Regulation Number 7. The Commission recognizes that there is some "compression" undertaken at well production facilities, and intends that those operations are part of the upstream segment, not the midstream segment (even if they would otherwise fall under the gathering and boosting segment as that term is used in the EPA's Greenhouse Gas Reporting Program). The Commission directs the Division to consider how centralized oil facilities, such as those receiving hydrocarbon liquids from tankless well production facilities, should be classified for purposes of these programs. The Commission has also defined the oil and natural gas compression segment to reflect the above; to clarify, if equipment is operated by the upstream operator at a well production facility, the equipment is not part of the oil and natural gas compression segment. However, if an emission point is located at a well production facility but operated by a midstream operator, that emission point is part of the oil and natural gas compression segment.

The Commission has defined "disproportionately impacted community" consistent with the definition in HB 21-1266. However, the statute does not call out 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 this program - and therefore the communities in which provisions of this program apply - are identified in the map. The Commission has included, in the definition of this term, a reference to the climate equity data map at which more detail can be seen of the boundaries of the disproportionately impacted communities addressed by this rulemaking. The Commission has also referenced a list of the census block groups by 12-digit FIPS code covered by the map incorporated into the definition, identifying what census blocks are disproportionately impacted communities as of the date of this rulemaking.

The Commission intends that the Division will preserve a copy of the map and the accompanying list in place at the time of this rulemaking such that sources may use the map and list as a guide for understanding the applicability of requirements. The Commission added the definition of natural gas processing segment, which is intended to mirror the applicability of sources reporting to EPA in the Greenhouse Gas Reporting Rule, 40 CFR Part 98, as the natural gas processing segment. The Commission added a definition of “preproduction emissions” and “production emissions”. It is the intent of the Commission that all emissions from the well, wellhead equipment (both permanent and temporary), the well production facility, and the piping between the wellhead and the well production facility – everything “upstream” of the midstream segment – are accounted for in one of these two definitions.

Midstream Steering Committee for Fuel Combustion Equipment: Part B, Section III.

The Commission recognizes that emissions from midstream fuel combustion equipment are a significant portion of the midstream segment’s greenhouse gas emissions. Emissions from fuel combustion equipment covered by this program include not only the carbon dioxide emissions, but also the methane and other greenhouse gases from that same equipment. For example, “methane slip” from engines, meaning the methane that is not combusted and that escapes unburnt into the atmosphere, is included in this program. The Commission also recognizes that reducing emissions from fuel combustion equipment, particularly as it involves electrification of large combustion equipment, will need to be carefully coordinated to ensure the continued reliability of Colorado’s power grid. As a result, the Commission established the Midstream Steering Committee to develop guidance for operators on how to develop each operator’s company-specific emission reduction plan, addressing the mechanisms and timetable for reducing greenhouse gas from fuel combustion equipment. The Commission adopted minimum requirements for participation on the steering committee. To the extent that more than one representative of a disproportionately impacted community participates on the steering committee, the Commission intends that more than one disproportionately impacted community would be represented. Recognizing that the Commission does not have the authority to require participation by the Colorado Energy Office or Public Utilities Commission staff but that their participation will be valuable, the Commission intends that the Division include them on the steering committee if they are willing.

The rules adopted by the Commission mandate that midstream segment owners and operators submit certain specified information to the steering committee by July 31, 2022. This information must include an identification of all fuel combustion equipment owned or operated by each midstream segment operator. There is no de minimis equipment that should not be identified, though not all equipment may end up in the operator’s ERP or the segment ERP.

This information should also allow the steering committee to easily understand what equipment - and how much emissions - are located within disproportionately impacted communities. Owners and operators must all include an estimate of the total annual power demand required for use of all midstream combustion equipment owned or operated by each midstream segment operator. When reporting this estimate, the owners and operators should identify whether such equipment is required to run continuously or whether operation of certain equipment is intermittent or interruptible. Owners and operators are also required to seek an estimate of existing transmission and/or distribution capacity to serve the estimated electric load (i.e. total power demand) at the specific locations of the midstream segment fuel combustion equipment, and provide that information to the steering committee.

Transmission and/or distribution capacity should be obtained from the appropriate electric utility, transmission, or distribution service provider and reported to the steering committee when made available by the utility or utilities. Owners and operators should evaluate whether their midstream segment fuel combustion equipment operations require firm or non-firm transmission service. Should an owner or operator consider potential electrification, the Commission intends the owner or operator will continue to engage with the appropriate electric utility, transmission, or distribution service provider.

If the midstream steering committee determines that it needs additional information, it may request it from the midstream segment operators. The rules provide that such additional information should be requested by April 30, 2022; however, this does not limit the Division's authority to use existing statutes and regulatory authority to require the submittal of additional information to the Division. The Division must preserve trade secrets and other confidential business information, if provided to the Division, as required by the Colorado Open Records Act. The Commission intends that the midstream steering committee work with electric utilities as well as regulatory agencies that have the information in publically available files. To the extent the midstream steering committee seeks voluminous information available from the PUC, the Commission encourages the midstream steering committee to first seek to obtain such information from the PUC directly. The Commission intends the electric utilities work collaboratively with the midstream steering committee to assist the committee in locating and, if necessary, clarifying such information. The Commission does not intend that the Division will provide, or that the steering committee will seek confidential or trade secret information from utilities, such as pricing information. The Commission intends that the electric utilities will work collaboratively with the midstream steering committee to assist the steering committee in locating and, if necessary, clarifying requested information.

The Division will provide the steering committee with the 2015 baseline for industrial greenhouse gas emissions, from which the midstream segment needs to achieve a twenty-percent (20%) reduction by 2030. While the Commission intends that reductions should be achieved as quickly as possible, the Commission does not demand a linear reduction in emissions between 2025 and 2030. Further, the emissions reductions considered in this 20% reduction requirement include only emissions from the fuel combustion equipment in the Industrial Sector of the GHG Roadmap. Emissions from the power sector (generally referred to as "Scope 2 emissions") that could result from electrification of midstream fuel combustion equipment, are considered under another portion of the GHG Roadmap.

The midstream steering committee will prepare a guidance document (or series of documents) to help midstream segment owners and operators in preparing their own company-specific emission reduction plans. The guidance document is not intended to be an independent analysis of electric grid availability or a forecast of available resources; it is designed to assist operators in identifying the issues they must consider when preparing their company ERPs. The Commission has asked that utilities participate on the midstream steering committee to help inform the issues that must be addressed in considering electrification as an emission reduction strategy, but this committee is not designed to perform independent analysis such as that performed by individual operators, utilities, or the PUC. The Commission intends that the guidance document will specify methods for calculating emissions from fuel combustion equipment, and that the Division must approve of the calculation methods before they can be included in the guidance.

Specifically, the Commission directs the Division to evaluate calculation methods used in the annual emission reports to the Division under Regulation Number 7, Part D, Section V., compare those with methods used to report to the U.S. EPA under the greenhouse gas reporting program and other available calculation methods, and determine the appropriate methods to be used by operators. The Commission expects consistency in the calculation and reporting methods used by operators, as much as practicable. The Commission directs the Division to ensure that midstream steering committee work product, like the guidance document, is translated into Spanish and made available with the draft guidance. The Commission also intends that the Division hold public meetings to receive feedback on the midstream steering committee work production (both the guidance and the midstream segment ERP), and that notice of these meetings be made at least thirty (30) days prior and that the notice and agenda be translated into Spanish.

Operators must submit company emission reduction plans to the steering committee in accordance with the requirements of Section III.D.4. and containing the information specified in the guidance and regulation. The Commission intends that the Division will prepare emission reduction requirements for any midstream owner or operator that does not timely submit its company ERP; however, if a company ERP is submitted late, the Division may nonetheless approve of inclusion of that company ERP into the segment ERP.

The Commission structured the rule such that the midstream steering committee submits a proposed regulatory package - with supporting analysis - to the Division instead of directly to the Commission. The Commission intends that the Division will review the steering committee's proposal, and use its independent judgment as to whether the proposal will ensure compliance with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. - i.e. achieves a 20% reduction in CO2e from the 2015 baseline - for the midstream segment. The midstream segment emission reduction plan submitted by the Division to the Commission will therefore be based on the segment-wide emission reduction plan developed by the midstream steering committee, but will consider the public comments received and the Division's evaluation of whether the steering committee's emission reduction plan will achieve the state's goals for CO2 reductions from midstream segment fuel combustion equipment.

<u>Upstream Greenhouse Gas Intensity: Part B, Section IV.</u>

In these revisions, the Commission has set targets for greenhouse gas intensity that step-down over time to achieve the GHG reductions required of upstream segment operations to meet the requirements of HB 21-1266. There is currently no regulatory greenhouse gas intensity program in the United States of which the Commission is aware. However, there are a number of voluntary programs, including ONE Future, the Natural Gas Sustainability Initiative, etc. Multiple Colorado operators are already participating in voluntary methane intensity programs.

While this program is new from a regulatory standpoint, the Commission feels it is an important program to guarantee - as much as possible - the emissions reductions needed from oil and gas upstream operations to meet the requirements of HB 21-1266. The Commission has adopted many regulations specific to oil and gas operations since 2005, including several since 2019 that are still in the process of being implemented. The regulations already adopted, in conjunction with other laws and regulations and the new direct regulations being adopted in this same rulemaking process in Regulation Number 7, Part D, will all provide the necessary emissions reductions. If existing and new measures are still not enough to ensure the emission reduction targets are met, this intensity program will require additional enforceable emission reduction actions from operators above their intensity targets. The Commission believes that the direct regulations adopted as part of this rulemaking along with those adopted and still being fully implemented will achieve or very nearly achieve the emission reductions required, and this intensity program will create an enforceable mechanism to ensure that any remaining required reductions are realized.

Notwithstanding the foregoing, in the event that the annual emissions inventories or other data collected by the Division reveals that the intensity program is not achieving the reductions necessary to achieve either the state's 2025 or 2030 greenhouse gas goals for these sectors, the Commission directs the Division to - consistently with the requirements of § 25-7-105(1)(e)(VII), C.R.S. - propose requirements that include additional direct regulation. The Commission intends that the same operator that accounts, in the intensity program, for the production under Section IV.D. and the emissions in the intensity calculation, is the operator that accounts for the emissions under Regulation Number 7 reporting requirements. For the purposes of this intensity program, this operator is referred to as the "Intensity operator," as defined in Regulation Number 22, Section IV.A.12.

Calculating Intensity

The Commission, for consistency across Colorado operations, determined that in converting natural gas production to barrels of oil equivalent, owners and operators should use the conversion factor of 5800 standard cubic feet of natural gas per barrel of oil equivalent. To clarify the calculation for intensity, which requires use of oil and natural gas production in thousand barrels of oil equivalent (kBOE), as well as the common units used for reporting natural gas production of million standard cubic feet (MMscf), operators should divide natural gas production reported in MMscf by 5.8 MMscf/kBOE.

The equation for calculating total production in kBOE is:

TP (kBOE) = [NGP (MMscf)/5.8 (MMscf/kBOE)] + [OP (bbl)/1000 (bbl/kBOE)]

Where:

TP (kBOE) = total annual production of natural gas and oil in the units of kBOE

NGP(MMscf) = annual natural gas production in the units of million standard cubic feet

OP (bbl) = annual oil production in the units of barrels of oil

The Commission set greenhouse gas intensity targets to cover all preproduction emissions and production emissions from upstream oil and gas operations. The intensity program covers emissions in both the “Industrial” sector and the “Oil and Gas” sector in the GHG Roadmap. The Commission recognizes that these sectors have different statutory targets for GHG reductions; the “Industrial” sector must meet a 20% reduction from the 2015 baseline by 2030, and the “Oil and Gas” sector must meet a 36% reduction from the 2005 baseline by 2025 and a 60% reduction from the 2005 baseline by 2030. The Commission adopted the projected throughput from the GHG Roadmap inventory work for purposes of setting these targets. However, the Commission understands that some stakeholders may sponsor a study of production forecasts to further inform and refine the established intensity targets. The Commission is willing to consider the results of such a study, and directs that the Division consider the results of any such study in the 2023 verification rulemaking (as discussed) and propose updating targets as appropriate. The Commission determined that it was appropriate to set more stringent intensity targets for the larger producers in the state (i.e., “majority producers”), than for the smaller producers (i.e., “minority producers”). The threshold set by the Commission for determining majority producers was based on accounting for the operators representing at least 80% of the state’s oil and natural gas production. The Commission recognizes that the smaller producers - that largely operate wells with declining production - have less opportunity to reduce intensity than the larger operators. However, the Commission does not intend that older facilities with declining production should just be permitted to operate with ever-increasing intensities, and directs the Division to study a potential facility-specific maximum allowable intensity and propose it as part of the 2023 verification rulemaking, if appropriate.

Acquisitions

The Commission adopted provisions providing how to adjust operator-specific reduction requirements upon the occurrence of asset transfer or other business realities. The Commission does not intend that operators may meet their greenhouse gas intensity targets simply by selling low-performing facilities, and the provisions for sales and acquisitions are designed to ensure both statewide emission reductions and greenhouse gas intensity targets are achieved. Generally, if an owner or operator sells its interest in a well or facility at some point during a calendar year, the owner or operator will report the production and emissions for the time period of its ownership, and the purchasing entity will report the production and emissions for the time period of its ownership, triggered by the closing date of the transaction. However, because majority and minority operators have different targets, the Commission clarifies how those situations should be addressed.

First, if a majority operator acquires assets from a minority operator, the majority operator would have some time before the acquired assets would be subject to the majority operator intensity targets. During the year of the acquisition, the majority operator need only demonstrate that the emissions and production from the acquired assets meet the minority operator targets – for the time period subsequent to the date of closing of the transaction.

However, in the calendar year after the acquisition, the majority operator would include the emissions and production from the acquired assets in its company-wide intensity calculation and need to meet the majority operator targets. Second, if a minority operator acquires assets from a majority operator, for the year of and the year following the acquisition, those assets need to meet the minority operator target for the acquired assets and would be included in the company-wide intensity calculation subject to the minority operator target. Under these situations, the Commission recognizes that there may be limited reasons why some additional time could be necessary. The Commission encourages operators to timely reach out to the Division if more time is required, and for the Division to work with operators that demonstrate equivalent or better emission reductions would be achieved. However, the timing of the acquisition itself, or the failure to conduct environmental due diligence prior to the acquisition, are not such limited reasons that the Commission intends the Division use its discretion to accept.

If, at any point, a minority operator has production over 10,000 kBOE, or if a minority operator increases its production by 2,500 kBOE over the prior calendar year production - then in the calendar year after the acquisition, the minority operator would become a majority operator and be subject to those targets (and other rules applicable to majority operators). Otherwise, if a minority operator acquires assets (or merges with) a minority operator, the minority targets must be met in the year of the acquisition for all assets, including the acquired assets. If a majority operator sells assets, the majority operator targets must still be met, even if that operator's production falls below 10,000 kBOE. If a new to market operator acquires the assets of a minority operator, the new to market operator becomes a minority operator and the minority operator targets apply; similarly, if a new to market operator acquires the assets of a majority operator, the majority operator targets apply.

New Facility Intensity

The Commission also determined that it was necessary to set a "new facility intensity" target, to recognize that operators of new well production facilities must continue to improve their performance, and reduce GHG emissions associated with new production. The Commission relied upon studies of intensity at oil and gas operations to determine that a new facility GHG intensity should be approximately 78.5% of the majority operator greenhouse gas intensity target. These new facility targets are in addition to the majority operator/minority operator targets in Section IV.B. So, a majority operator who constructs a new well production facility in 2027 must meet: (1) the greenhouse gas intensity target in Section IV.B.3.a. for all its upstream segment operations including the newly constructed well production facility (and subsequent majority operator targets in Section IV.B.); (2) the new facility intensity target in Section IV.C.3. for calendar year 2027 for the newly constructed well production facility; and (3) the new facility intensity target in Section IV.C.4. for calendar year 2028 for the newly constructed well production facility.

Greenhouse Gas Intensity Plans

In Section IV.E, the Commission requires that owners or operators submit greenhouse gas intensity plans. The primary purpose of these plans is for owners or operators to demonstrate to the Division how they intend to meet the 2025, 2027, and 2030 greenhouse gas intensity targets in Sections IV.B.2. through IV.B.4. The Commission determined to require submittal of site-specific plans that identify at which sites emission reductions will be achieved to ensure that the greenhouse gas intensity targets are met, all the way through the 2030 targets. The Commission intends that operators be permitted to update their plans after submittal, but the greenhouse gas intensity plan in effect must always demonstrate that the targets will be achieved.

The Commission is also requiring annual verifications identifying what actions were taken, consistent with the plans. In addition to annual verifications to the intensity plans, the Commission has required submittal of asset transfer plan updates specific to any assets a company purchases. These assets transfer plans are to ensure that operators do not purchase high-intensity sites from another operator without making any improvements to those sites that would have been made if the sites had not been transferred. The Commission adopted this requirement to protect the integrity of the program and ensure emission reductions are realized as expected.

Verification

In Section IV.F., the Commission directs the Division to develop a mechanism to track progress towards meeting the state's GHG reduction goals and to evaluate compliance with the greenhouse gas intensity targets and new facility intensity targets in Sections IV.B. and IV.C. The Commission determined that it was advisable to give the Division time in 2021 and 2022 (1) to evaluate the annual emission reports submitted in 2021 and 2022, (2) to evaluate different calculation and emission quantification methodologies for different emitting activities and equipment, and (3) to consider the impact and results of the aerial and ground-based survey work being conducted by the Division (and contractors) in 2021 (because this data will not be fully available until the spring of 2022) as well as other relevant surveys. In 2023, the Commission expects that the Division will propose a verification plan after considering the current status of oil and gas GHG emissions, based on Regulation Number 7 reporting and top-down monitoring results, production increases or decreases based on data reported to the OGCC, the aerial and ground-based survey work, and other important considerations, such as the availability, reliability, and cost-effectiveness of direct measurement techniques as appropriate. This 2023 rulemaking may also address other aspects of the intensity program, including evaluating progress towards the reduction targets for oil and gas in § 25-7-105(1)(e)(XII).

Disproportionately Impacted Communities

The Commission recognizes the critical need for emission reductions - and in particular emission reductions of GHG co-pollutants - within disproportionately impacted communities. The Commission also included the definitions of "co-benefits" and "harmful air pollutants." These terms are used in Sections III. and IV. to ensure that the midstream segment emission reduction plan and operators' greenhouse gas intensity plans achieve and prioritize reductions of co-pollutants in disproportionately impacted communities. In Section III., the Commission has included a requirement that operators prioritize and quantify reductions of co-pollutants within disproportionately impacted communities in their ERPs. In Section IV, the Commission required that greenhouse gas intensity plans identify the facilities in disproportionately impacted communities and demonstrate how co-pollutant emission reductions will be prioritized therein. The Commission is further requiring that annual verifications to intensity plans demonstrate that emission reductions were prioritized in disproportionately impacted communities, and must quantify the reductions of harmful air pollutants. The Commission intends that where the same or similar technological and economic considerations apply to reductions that can be achieved in a disproportionately impacted community or elsewhere, as it pertains to determining at which facilities or which activities to reduce emission, reductions within disproportionately impacted communities must be prioritized over other GHG reduction options. The 2023 verification rulemaking may also include regulatory provisions addressing how the Division will evaluate compliance with the requirement to prioritize reductions in disproportionately impacted communities.

The Commission also directs the Division to work with the Environmental Justice Unit at CDPHE to ensure access to GHG Intensity Plan information – and the impact of GHG Intensity Plans on DI Communities – by the residents of those communities. The Commission has also included, in related revisions to Regulation Number 7, Part D, Section VI., a direction that the Division report out on these issues to the Commission on an annual basis.

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:

§ 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 § 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 no federal regulations applicable to the situations covered by the provisions of Part B, Sections III and IV. However, 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 (40 CFR Part 98) and New Source Performance Standards (30 CFR Part 60) Subparts KKK, OOOO, and OOOOa. Part B, Sections III and IV do not conflict with any applicable current federal regulations. 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. EPA also asks states to consider environmental justice as part of their actions, though there are no specific 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 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 Part B, Sections III and IV. 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 programs will ensure that the regulated community can achieve required GHG emissions reductions in cost-effective ways by giving covered entities options to reduce emissions through direct regulation and development of company-specific plans to ensure compliance with state targets.

(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.

(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. The rules adopted by the Commission establish a new midstream steering committee to assist in analyzing the technical feasibility and economic reasonability of future means of reducing emissions in this segment. The midstream steering committee will prepare a guidance document (or series of documents) to help midstream segment owners and operators in preparing their own company-specific emission reduction plans, thus allowing for additional time to achieve compliance. The upstream intensity program also accommodates uncertainty, by allowing for an additional year (at least) to consider and develop a verification program.

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

With respect to any sources already operating within the upstream segment, the rule establishes reasonable equity because it takes into account the size of the operator, the percentage of ownership each operator claims, and the location of the facility. With respect to any new well production facilities subject to the upstream statewide intensity program requirements, the rule establishes reasonable equity as requirements are the same for each source type based on age of the production well. This is also demonstrated for the midstream segment with the establishment of the midstream steering committee to ensure equity across operators based on location and utility provider.

(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 Part B, Sections III. and IV. 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 § 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.

(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, 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, 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.

<u>Findings of Fact</u>

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 alternative 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.

Z. December 15, 2022 (Revisions to Part A, Sections I., II., and Appendix A; Part B, Sections IV. and VI.; Part C, Sections I., II., III., and IV.; Part D, Sections I., II., and III.; and Part E, Sections I., II., III., IV., VI., VII., and VIII.)

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

On October 7, 2022, EPA reclassified the Denver Metro/North Front Range (DM/NFR) to severe for the 2008 8-hour Ozone National Ambient Air Quality Standard of 75 parts per billion (ppb) (2008 NAAQS), after 2019-2021 ozone data failed to show attainment. See Fed. Reg. 60926. Separately, EPA has also designated the DM/NFR as marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, effective August 3, 2018 (83 Fed. Reg. 25776 (June 4, 2018)). On November 30, 2021, EPA expanded the boundary of the 2015 ozone nonattainment area to include all of Weld County, effective December 30, 2021 (86 Fed. Reg. 67864). On October 7, 2022, EPA reclassified the DM/NFR and northern Weld County to moderate, after 2019-2021 ozone data failed to show attainment. See Fed. Reg. 60897. To ensure progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission adopted revisions to Regulation Number 7 to include reasonably available control requirements (RACT) for major sources of volatile organic compounds (VOC) or nitrogen oxides (NOx) in the nonattainment areas, specifically for combustion equipment, wood coating, solvent use, bakery operations, digital printing, poultry waste processing, oil stabilization facilities, class II injection well facilities, and industrial waste; to include state only provisions in the SIP concerning specific oil and gas sector engines, pneumatic controllers, and liquids loadout as SIP strengthening measures; to clarify the applicability of requirements to newly classified ozone nonattainment areas; to include provisions corresponding to recommendations in EPA's Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings (Miscellaneous Metal CTG) concerning motor vehicle materials; and to include provisions establishing VOC content limits on automotive coatings. The Commission also adopted revisions to expand gasoline tank truck testing requirements.

Statutory Authority

The State Air Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants. Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a) and (2) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources and emission control regulations pertaining to nitrogen oxides and hydrocarbons.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rationale for the adoption of the revisions. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Major Source RACT

Due to the reclassifications to severe and moderate, Colorado must submit revisions to its SIP to address the Clean Air Act's (CAA) ozone nonattainment area requirements, as set forth in CAA §§ 172, 182(b), 182(d), and the final SIP Requirements Rules. Severe and Moderate SIPs must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., sources in a severe nonattainment area that emit or have the potential to emit 25 tpy or more and sources in a moderate nonattainment area that emit or have the potential to emit 100 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the nonattainment area.

Therefore, to address the severe nonattainment area requirements under CAA § 182(d), the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 25 tpy major sources of VOC and/or NOx including expanding the combustion equipment requirements; expanding wood coating requirements; expanding solvent use requirements; incorporating requirements in the SIP for oil stabilization and class II injection well facilities; and developing new categorical rules for bakery operations, digital printing, poultry waste, and industrial waste. To address the moderate nonattainment area requirements under CAA § 182(b), the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 100 tpy major sources of VOC and/or NOx in northern Weld County including clarifying the applicability of SIP provisions to any ozone nonattainment area, in contrast to the specified 8-hour ozone control area; expanding the combustion equipment requirements; and expanding requirements for oil and gas operations and equipment. The Commission also adopted revised requirements for glass melt furnaces.

Boilers

In 2019, the Commission expanded the combustion equipment requirements adopted in 2016 and 2018 for the 100 tpy major sources to the 50 tpy major sources. The Commission now further expands the categorical RACT requirements to boilers at 25 tpy major sources in the 8-hour ozone control area and at 100 tpy major sources in northern Weld County. The Commission also adopted an emission limit for wood fired boilers at 25 tpy major sources. The owners or operators of these boilers will comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Engines

In 2019, the Commission expanded the NOx emission limit requirements for compression ignition reciprocating internal combustion engines (RICE) and combustion process adjustment requirements for stationary RICE. The Commission now further expands the categorical RACT requirements for engines at 25 tpy major sources in the 8-hour ozone control area and at 100 tpy major sources in northern Weld County. The owners or operators of these engines will continue to comply with the specified NOx emission limit or applicable NSPS NOx limit, combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Turbines

In 2019, the Commission adopted provisions requiring turbines constructed before February 18, 2005, to comply with NSPS GG and turbines construction after February 18, 2005, to comply with NSPS KKKK. In 2020, the Commission adopted revisions to require all turbines to comply with emission limits in NSPS KKKK. The Commission now further expands the categorical RACT requirements to turbines at 25 tpy major sources in the 8-hour ozone control area and at 100 tpy major sources in northern Weld County. As with the previous adoption of the NSPS KKKK limits, the Commission intends the limits to apply as EPA has written in the rule. The Commission also adopted specific requirements for one facility based on the permitted emission limits and monitoring requirements. All turbines will continue to comply with good air practices for minimizing emissions, combustion process adjustment, and recordkeeping requirements.

Process heaters

In 2021, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for process heaters at major sources of NOx emissions, specifically NOx emission limits for natural gas-fired and refinery gas-fired process heaters with a heat input rate greater than or equal to 5 MMBtu/hr. The Commission also expanded these provisions on a state-only basis to process heaters at sources that emit, or have the potential to emit, 25 tpy NOx, in anticipation of a reclassification to severe nonattainment. The Commission now removes the state-only designation to include these requirements in the SIP. The Commission also expanded the categorical RACT requirements to process heaters at 100 tpy major sources in northern Weld County.

Glass melt furnaces

In 2018, the Commission adopted requirements for glass melt furnaces at 100 tpy major sources in the 8-hour ozone control area. In this rulemaking, the Commission revised those requirements to address concerns expressed by EPA about start-up and shut-down operations that were excluded from the NOx emission limit, as adopted based on applicable federal requirements. The revised limit now applies during all periods except for initial startup where the owner or operator must account for startup emissions by calculating emissions from fuel consumption.

Wood coating

In 2020, the Commission adopted requirements for wood surface coating based on recommendations in EPA's Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations CTG (Wood Furniture CTG) (1996) and EPA's A Guide to the Wood Furniture CTG and NESHAP (1997). The Commission now expands the wood surface coating requirements to the surface coating of other wood products 25 tpy major sources in the 8-hour ozone control area.

Solvent use

In 2019, the Commission adopted a new categorical rule regarding general solvent use operations. The Commission now expands the solvent use requirements to operations at 25 tpy major sources in the 8-hour ozone control area.

Bakery operations

The Commission adopted a new categorical rule for bakery ovens and bakery scrap recycling at 25 tpy major sources in the 8-hour ozone control area. The primary VOC associated with baking is ethanol, produced when yeast reacts with sugars in bread dough. VOC emissions also result from the drying of bakery scrap product. The new requirements reduce VOC emissions through the use of work practices and by routing bakery oven emissions to a control device. One potentially subject facility is newly installing such control device and the adopted requirements provide an appropriate implementation time period for such installation. The applicable work practices and recordkeeping requirements will continue to apply.

Digital printing

The Commission adopted a new categorical rule for digital printing operations at 25 tpy major sources in the 8-hour ozone control area. The adopted work practice and recordkeeping requirements are similar to those adopted in other ozone nonattainment areas and will reduce fugitive VOC emissions from printing.

Poultry waste processing

The Commission adopted a new categorical rule for poultry waste dryers at 25 tpy major sources in the 8-hour ozone control area. The adopted work practices will reduce VOC emissions from the drying of poultry waste (i.e., manure and spent hens).

Solid waste facilities

The Commission adopted a new categorical rule for solid waste disposal at 25 tpy major sources in the 8-hour ozone control area. The adopted work practices and recordkeeping requirements will reduce VOC emissions from facilities that dispose of oil and gas wastes. The Commission does not intend at this time for these provisions to apply to municipal solid waste landfills, produced water disposal facilities, or oil and gas operations that generate oil and gas waste.

Oil and gas sources

The Commission expanded the applicability of specific existing oil and gas SIP provisions in Part D, Section I. to oil stabilization facilities and class II injection well facilities at 25 tpy major sources in the 8-hour ozone control area. The expanded requirements are currently applicable on a state-only or permit basis but may require additional recordkeeping. The Commission notes that the definition of centralized oil stabilization facility currently only applies to one facility and is not intended to apply to facilities that receive combined produced water and condensate/crude oil that flows from a wellhead to a production or centralized tank battery.

Automotive

Automotive materials

In 2021, the Commission revised the metal surface coating requirements in Regulation Number 7 to update the provisions based on EPA's 1978 CTG and correspond to the recommendations in EPA's 2008 Metal Coating CTG. The Commission did not, at that time, propose to incorporate the VOC content limits for certain motor vehicle materials used at facilities that are not automobile or light-duty truck assembly coating facilities due to the overlap with EPA's national rule, National Volatile Organic Compound Emission Standards for Automobile Refinish Coatings (40 CFR Part 59 Subpart B).

EPA has since raised concerns about the differing definitions concerning motor vehicle materials, and thus potential applicability, between EPA's Metal Coating CTG and EPA's National Automobile Rule. Therefore, the Commission now incorporates the motor vehicle materials VOC content limits and associated work practices into Regulation Number 7.

Automotive coatings

The Commission adopted VOC content limits, and associated work practices and recordkeeping, as contingency measures for the Moderate SIP. The California Air Resources Board (CARB) developed a Suggested Control Measure for Automotive Coatings (SCM) that achieves additional reductions of VOCs from automotive coatings beyond EPA's national automobile refinish rule. The adopted requirements will apply to anyone who sells, supplies, offers for sale, or manufacturers specified automotive coatings and any person who applies or solicits the application of specified automotive coatings should Colorado fail to attain the 2015 ozone NAAQS by the applicable moderate attainment date.

NAA applicability

The Commission adopted revisions to Regulation Number 7 to clarify the applicability of Regulation Number 7 to "an ozone nonattainment" area. Regulation Number 7, Part A, Sections I.B.2.d. and II.C.1.d.(iii) require existing sources in any ozone nonattainment area to comply with applicable requirements in Regulation Number 7, whereas the other applicability provisions in Regulation Number 7 apply to sources in the 8-hour ozone control area. The 8-hour ozone control area, as defined, does not include the northern portion of Weld County recently included by EPA in the 2015 ozone NAAQS nonattainment area. These provisions in Part A, Sections I. and II. were adopted in 2008 on a state-only basis during the expansion of Regulation Number 7 requirements to sources outside of the historic 1-hour ozone nonattainment area (i.e., the remaining portion of the 8-hour ozone control area under the 75 ppb standard). However, the implementation timeframes in Sections I.B.2.b. and II.C.1.d.(iii) conflict, particularly in relation to the description from the adoption of the provisions that "existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements."

Therefore, the Commission aligned and clarified the timelines for implementation of applicable requirements in Regulation Number 7 to existing sources in the northern portion of Weld County. Specifically, the Commission adopted revisions to clarify that, broadly, existing sources in northern Weld County must comply with applicable requirements within three years from the date of nonattainment designation (i.e., December 31, 2024), and, more specifically, that existing oil and gas sources must comply beginning February 14, 2023, (i.e., the effective date of adoption) to recognize that many oil and gas operations were already subject to state-only requirements that are the same and/or similar to the SIP requirements. The Commission recognizes that Weld County has challenged EPA's expansion of the 2015 ozone nonattainment area boundary and directs the Division to evaluate the use of the term "northern Weld County" as related to the ozone nonattainment area following the conclusion of the litigation, as necessary. The Commission does not use the term "northern Weld County" to indicate any particular culpability of Weld County as related to the ozone nonattainment classification but selected that term for consistency, clarity for potentially impacted sources, and necessary alignment of implementation timeframes, as discussed above. The Commission also updated the maps and chronology in Appendix A.

Inclusion of state-only provisions in the SIP

As SIP-strengthening measures, the Commission adopted state-only requirements into the SIP. Specifically, the Commission adopted requirements for specific 1,000 hp engines (requirements adopted in 2020), requirements for new well production facilities and natural gas compressor stations to use non-emitting pneumatic controllers (requirements adopted in 2021), and requirements to control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles (requirements adopted in 2019). The engine tables A and B in Part E, Section I.D.4.c were built based on operator engine reporting that began in 2021.

As part of that reporting, operators identified engines fleet-wide that could achieve emission reductions through permitted emissions reductions, installation of additional controls, and engine replacement. The listing of specific engines in Table A does not preclude operators the ability to replace an engine in accordance with an authorized Alternative Operating Scenario (AOS) contained in a permit provided that the replacement engine meets or exceeds the applicable emission standard of the engine being replaced, in accordance with Sections I.D.5.b.(vi)(A) or I.D.5.b.(vi)(B). These requirements for pneumatic controllers, loadout, and specific engines now apply in the SIP for subject owners or operators in the ozone nonattainment area. In providing different compliance schedules for the provisions as included in the SIP as compared to the compliance schedules adopted with as state-only, the Commission does not intend to provide a gap in compliance for owners or operators already complying with the state-only provisions but includes compliance dates for SIP applicability purposes.

Gasoline tank truck testing

The Commission expanded the gasoline tank truck testing provisions to encourage the use of emission controls and support year-round testing. The testing provisions, based on EPA's CTGs, in particular the Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (1978), limited testing to October through April. Neither EPA's CTGs nor the required Method 27 limit the calendar time during which testing must occur but both direct that gasoline vapors be purged from the gasoline tank truck before conducting the leak-tightness test to avoid residual gasoline vapors causing testing inconsistencies. Because these provisions are in Colorado's SIP, Colorado must demonstrate that revising the provisions will not cause an interference with Colorado's ability to attain or maintain the NAAQS. See CAA 110(l). The estimated uncontrolled emissions from the testing of 1,800 gasoline tank trucks (tests in 2021) are 80 tpy.

Currently, there are four testing facilities located in the DM/NFR, four located outside the DM/NFR, and two remote testing facilities. Controlling the purged vapors that occur as part of the testing procedure would result in an emissions reduction of 76 tpy, if all testing facilities chose the proposed testing schedule option. To use this year-round testing schedule option, testing facility operators must also control vapor purge emissions that occur for other reasons, such as gasoline tank truck repair, which would result in additional controlled emissions reductions. The Commission also adopted combustion device inspection and monitoring requirements to maintain equipment, improve performance, and reduce emissions. As with a similar provision adopted in 2019, the Commission does not intend that owners or operators should shut-in the combustor for the sole purpose of performing the inspection of the burner tray. Further, owner or operators need only inspect those portions of the burner trays that are visible without shutting-in the combustor. Therefore, the option allowing year-round testing so long as the testing facility operator controls all vapor purge emissions from testing or other purging will reduce emissions and will not interfere with attainment or maintenance of the NAAQS.

Clean-up

The Commission adopted revisions to reflect the intended reporting time frame in Part E, Section I.D.5., correcting the reporting start year from 2022 to 2023. The reporting requirement in Part E Section I.D.5.g.(iii) is for monitoring that did not begin until 2022. Operators are supposed to report monitoring information from the "previous calendar year."

The Commission corrected typographical errors in Part D, Section II.H., specifically in Section II.H.3.c. to correct numbering, in Section II.H.2.f.(i) to correct a citation, and in Section II.H.1.c.(vii) to correct applicability, and in Section II.H.5.c. to correct a numbering error.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7.

Supplemental Information

Improving air quality in Disproportionately Impacted (DI) Communities is critical and the Commission is committed to advancing Environmental Justice. Though these SIP revisions may not have strategies that limit emissions in DI Communities specifically, the Commission is committed to doing so in future hearings. The ozone reductions garnered by these SIP revisions will improve the health of DI and other communities.

The Commission intends to continue to reduce ozone precursors that are so often emitted in or near DI Communities. These precursors and the ozone they form and other pollutants can have serious health impacts. It is anticipated that EPA will have Environmental Justice Guidance soon and the Commission encourages the Division to use this guidance and the CDPHE's Environmental Justice Action Task Force recommendations, and to continue the work it is doing and to prepare regulations that will improve Air Quality and health in DI Communities. Consistent with its mandates to expeditiously attain the ozone NAAQS, reduce greenhouse gases, and protect disproportionately impacted communities, the Commission expects the Division to work with the Regional Air Quality Council to commence stakeholder processes in 2023 to evaluate ozone reduction strategies, and their benefits and impacts on the Division's other air quality and equity goals, and propose to the Commission for rulemaking those beneficial and cost-effective strategies needed to achieve attainment of the 2008 and 2015 ozone standards.

The stakeholder process should evaluate ozone reduction strategies across a broad range of ozone precursor sources, which should include, at a minimum:

- Prohibitions on gasoline-powered lawn and garden equipment sales, and further incentives for the conversion of gas-powered equipment to electric;
- Additional non-road equipment reduction strategies;
- Building and appliance efficiency standards;
- Residential auto maintenance incentives;
- Commercial diesel best practices initiatives;
- Advanced Clean Cars II standards;
- Strengthening the vehicle inspection and maintenance program;
- Mobile source credits as part of nonattainment new source review;
- Additional/permanent funding for VMT reducing strategies such as zero-fare transit, increased transit services, and bicycle and walking infrastructure;
- Emission reduction approaches for indirect sources;
- Additional industrial source emission reduction requirements, such as flaring minimization requirements at applicable sources, episodic and seasonal restrictions on industrial and commercial activities, oil and gas pre-production activities, rules to reduce emissions from gas-fired reciprocating internal combustion engines (RICE) in the oil and gas sector, requiring emission offsets or aggregation of wellhead and production facility equipment when permitting oil and gas sector minor sources, and zero-emitting retrofits for all existing pneumatic devices;
- and any other measures that the Division determines would assist in attainment of the ozone NAAQS.

In the case of the Colorado Clean Cars rule, the Commission expects that the Division will make a proposal consistent with the State's 2023 Electric Vehicle Plan. Per its 2019 resolution, the Commission expects the Division to report on the impacts and benefits of proposed ozone reduction strategies on achieving the state's nitrogen deposition reduction goals in Rocky Mountain National Park as part of future ozone reduction rulemakings.

<u>Additional Considerations</u>

Colorado must revise Colorado's ozone SIP to address the severe and moderate ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's nonattainment area obligations. These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), CRS, the Commission determines:

(I) The revisions to Regulation Number 7 address process heaters, boilers, turbines, engines, ceramic kilns, dryers, furnaces, wood coating, solvent use, industrial waste, bakery operations, poultry waste operations, digital printing, gasoline tank trucks, automotive materials, and the oil and gas sector. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NSPS IIII, NSPS JJJJ, NSPS GG, MACT KK, MACT DDDDD, MACT JJJJJJ, MACT BBBBBBB, MACT CCCCCC, MACT ZZZZ, MACT YYYY, MACT HH, MACT HHH, and 40 CFR Part 59 Subpart B may also apply to and the above listed equipment and operations. However, the revisions to Regulation Number 7 apply on a broader basis.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply.

(III) The CAA establishes the 2008 and 2015 NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's ozone nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established Colorado's SIP-RACT implementation deadlines. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 strengthen Colorado's SIP. These sections currently address emissions from combustion equipment, wood coating, solvent use, industrial waste, bakery operations, poultry waste operations, digital printing, gasoline tank trucks, automotive materials, and the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's industry.

(VII) The revisions to Regulation Number 7 establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable. The revisions concerning major sources of NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, and NOx to help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the ozone nonattainment area requirements. However, to the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of VOCs and NOx 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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

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

AA. April 20, 2023

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-101, C.R.S., et seq., the Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 C.C.R. §1001-1.

<u>Basis</u>

To improve the readability and usability of Regulation Number 7 and Regulation Number 22, the Commission adopted revisions restructuring and reorganizing the parts and sections.

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 § 25-7-103.3, directs rule-making agencies, such as the Commission, to review their rules and consider whether the rule is necessary; whether the rule overlaps or duplicates other rules of the agency or with other federal, state, or local government rules; whether the rule is written in plain language and is easy to understand; whether the rule has achieved the desired intent and whether more or less regulation is necessary; whether the rule can be amended to give more flexibility, reduce regulatory burdens, or reduce unnecessary paperwork or steps while maintaining its benefits; whether the rule is implemented in an efficient and effective manner, including the requirements for the issuance of permits and licenses; whether a cost-benefit analysis was performed by the applicable rule-making agency; and whether the rule is adequate for the protection of the safety, health, and welfare of the state or its residents. Based on this review, the rule-making agency will determine whether the existing rules should be continued in their current form, amended, or repealed.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7. The Commission reorganized Regulation Number 7 into four regulations: Part B became Regulation Number 24; Part C became Regulation Number 25; Part D remained in Regulation Number 7; and Part E became Regulation Number 26. The upstream oil and gas intensity and midstream combustion program provisions currently in Regulation Number 22 moved to Regulation Number 7. The manufacturing sector greenhouse gas provisions in Regulation Number 22 became a new Regulation Number 27.

To assist in tracking the history of the regulatory revisions, associated statements of basis and purpose, and restructured location, the Commission provides the following tracking table.

Year of rule adoption	Date of rule adoption	Summary of rule(s) adopted	Regulation 7 Section (pre-2019 numbering)	Regulation 7 Section (numbering as of 12.2022)	Rule & Section (as of 4.2023)
1995	Dec. 21	Clarify substances that are negligibly reactive VOCs.	Section II.B.	Part A, Section II.B.	Regulations 7 and 24-26, Part A
1996	Mar. 21	Revisions related to the maintenance demonstration.	Sections I.A.1. through I.A.4.; II.D.; II.E.	Part A, Sections I.A.1. through I.A.4.; II.D.; II.E.	Regulations 7 and 24-26, Part A
1996	Nov. 21	Updated NRVOC list. Removed control of VOC emissions from dry cleaning facilities using perchloroethylene.	Section XII.	NA	NA
1998	Oct. 15	Revisions specific to Gates Rubber Company.	Section II.F.	NA	Regulation 24-25, Part A
2001	Jan. 11	Correct discrepancies in posted versus adopted provisions.	Sections III.C.; IX.L.2.c.(1); X.D.2. through XI.A.3.	Part B, Section I.; Part C, Section I.; Part C, Sections II. through III.	Regulation 24, Part B; Regulation 25, Part B (fkna Part C)
2003	Nov. 20	Repealed provisions establishing a procedure for granting exemptions for de minimis sources and for approving alternative compliance plans.	Sections I.A.2. through I.A.4.; II.D.; II.E.	Part A, Sections I.A.1. through I.A.4.; II.D.; II.E.	Regulations 7 and 24-26, Part A
2004	Mar. 12	Revisions adopted in conjunction with the early action compact ozone action plan – control of emissions from condensate operation at oil and gas	Sections I.A.; I.B.; XII.; XVI.	Part A, Section I.A.; Part A, Section I.B.;	Regulations 7 and 24-26, Part A

Year of rule adoption	Date of rule adoption	Summary of rule(s) adopted	Regulation 7 Section (pre-2019 numbering)	Regulation 7 Section (numbering as of 12.2022)	Rule & Section (as of 4.2023)
		facilities, emissions from internal combustion engines, emissions from gas processing plants, and emissions from oil and gas operations dehydrators.		Part D, Section I.; Part E, Section I.	
2004	Dec. 16	Revisions adopted in response to EPA comments (re practical enforceability) on the ozone action plan adopted 3/2004.	Sections I.A.; II.A.; XII.; XVI.;	Part A, Section I.A.; Part A, Section II.A.; Part D, Section I.; Part E, Section I.	Regulations 7 and 24-26, Part A
2006	Dec. 17	Expanding oil and gas condensate tank emission controls.	Section XII.	Part D, Section I.	Regulation 7, Part B (fkna Part D)
2006	Dec. 17	Reduce emissions from oil and gas operations and natural gas fired engines.	Sections I.A.1.b.; XVII.	Part A, Section I.A.; Part D., Section II. & Part E. Section I. (for engines)	Regulation 7, Part A and Part B (fkna Part D); Regulation 26, Part A and Part B (fkna Part E)
2008	Dec. 12	Expand VOC RACT requirements for 100 tpy sources and clarify how RACT requirements in Regulation Numbers 3 and 7 interact in the ozone nonattainment area. Make typographical and formatting changes. Revise oil and gas condensate tank and pneumatic controller requirements.	Title; Sections I.; II.; VI. through XIII.; XVII.; XVIII.; and Appendices A through F	Part A, Section I.; Part A, Section II.; Part B, Sections IV. through VI. & Part C, Sections I. through IV. & Part D, Section I.; Part D, Section II. and Part E, Section I. (for engines); Part D, Section III.; Part A, Appendix A. & Part B, Appendices B and C & Part C, Appendices D and E (formerly Appendix F)	Regulation 24, Part B; Regulation 25, Part B (fkna Part C); Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E)
2011	Jan. 7	Include engine requirements in the Regional Haze SIP.	Outline; Sections I.; XVII.	Part A, Section I.; Part E, Section I.	Regulation 26, Part B (fkna Part E)
2012	Dec. 20	Address EPA comments on the June 2009 submittal. Revise state-only requirements for consistency.	Sections II.; XII.; XVII.	Part A, Section II.; Part D, Section I.; Part D, Section II.	Regulation 7, Part B (fkna Part D)
2014	Feb. 23	Adopt additional oil and gas emission reduction requirements – auto-igniters,	Sections II.; XVII.; XVIII.	Part A, Section II.;	Regulation 7, Part B (fkna

Year of rule adoption	Date of rule adoption	Summary of rule(s) adopted	Regulation 7 Section (pre-2019 numbering)	Regulation 7 Section (numbering as of 12.2022)	Rule & Section (as of 4.2023)
		expand condensate tank controls, limit storage tank venting, expand dehydrator control, establish leak detection and repair program, limit venting during well maintenance and liquids unloading, expand pneumatic controller requirements.		Part D, Section II.; Part D, Section III.	Part D)
2016	Nov. 17	Adopt RACT requirements for industrial cleaning solvents, lithographic and letterpress printing, and specific major sources. Including existing combustion device auto-igniter and storage tank inspection requirements in the SIP. Adopting major source combustion equipment combustion process adjustment requirements and incorporate by reference NSPS and NESHAP for specific major sources.	Sections I.; X.; XII.; XIII.; XVI.; XIX.	Part A, Section I.; Part C, Section II.; Part D, Section I.; Part C, Section IV.; Part C, Section V.; Part E, Section III.	Regulation 25, Part B (fkna Part C); Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E)
2017	Nov. 16	Adopt provisions based on recommendations in EPA's Oil and Gas Control Techniques Guideline. Revise state-only requirements for consistency.	Sections II.; XII.; XVII.; XVIII.	Part A, Section II.; Part D, Section I.; Part D, Section II.; Part D, Section III.	Regulation 7, Part B (fkna Part D)
2018	July 19	Adopt requirements for existing major source boilers, turbines, lightweight aggregate kilns, glass melting furnaces, engines.	Sections XVI.; XIX.	Part E, Section II., Part E, Section III.	Regulation 26, Part B (fkna Part E)
2018	Nov. 15	Adopt requirements for major source breweries and wood furniture manufacturing. Address EPA concerns with requirements for industrial cleaning solvents, metal furniture surface coating, and miscellaneous metal surface coating. Updated incorporation by reference dates.	Sections I.; II.; VI.; VIII.; IX.; X.; XII.; XIII.; XVI.; XVII.; XIX.; XX.; XXI.	Part A, Section I.; Part A, Section II.; Part B, Section IV; Part B, Section VI.; Part C, Section I.; Part C, Section X.; Part D, Section I.; Part C, Section IV.; Part C, Section V.; Part D, Section II.; Part E, Section III.; Part E, Section IV. Part F	Regulation 24, Part B; Regulation 25, Part B (fkna Part C); Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E); Regulation 23 (fkna Part F)
2019	Dec. 19	Reorganized into Parts A through F. Replaced the SIP system-wide condensate tank control program with a fixed threshold storage tank control program. Increased state-only, state-wide storage tank controls. Adopted oil	Sections I. through XX. and Appendices A through F	(see reorganization cross walk)	

Year of rule adoption	Date of rule adoption	Summary of rule(s) adopted	Regulation 7 Section (pre-2019 numbering)	Regulation 7 Section (numbering as of 12.2022)	Rule & Section (as of 4.2023)
		and gas storage tank measurement system, hydrocarbon liquids loadout, leak detection and repair, well plugging, and pneumatic controller requirements. Adopted an oil and gas transmission and storage segment methane intensity program. Adopted an annual oil and gas inventory program. Expanded SIP requirements to 50 tpy sources. Aligned gasoline tank truck testing requirements with federal requirements as SIP clean-up.			
2020	Sept. 23	Adopted requirements for natural gas fired 1,000 horsepower engines. Adopted flowback vessel control requirements and pre- and early-production monitoring requirements. Expanded hydrocarbon liquids loadout requirements to class II disposal well facilities.		Part D, Sections II.; IV.; V.; VI.; Part E, Section I.	Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E)
2020	Dec. 18	Adopted requirements for major source foam manufacturing, boilers, turbines, landfill and biogas fired engines, and wood surface coating.		Part D, Section II.; Part E, Sections II.; IV.; V.	Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E)
2021	Feb. 18	Adopted non-emitting pneumatic controller requirements for new facilities and existing pneumatic controller retrofit requirements for existing facilities.		Part D, Section III.	Regulation 7, Part B (fkna Part D)
2021	July 16	Adopted requirements for metal parts surface coating and major source process heaters.		Part C, Section I.; Part D, Section III.; Part E, Section II.	Regulation 25, Part B (fkna Part C); Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E)
2021	Dec. 17	Adopted SIP revisions to address EPA concerns with the EPA Oil and Gas CTG. Adopted oil and gas combustion device performance testing requirements. Expanded reciprocating compressor rod packing, leak detection and repair, and pneumatic controller requirements at natural gas processing plants. Expanded leak detection and repair, separator, and well maintenance requirements. Adopted pigging and blowdown requirements.		Part D, Sections I., II., III., V., VI.	Regulation 7, Part B (fkna Part D)
2022	Dec. 15	Adopted requirements for major source combustion equipment, wood coating, solvent use, bakery operation, digital printing, poultry waste processing, oil stabilization facilities,		Part E, Sections I., II., III., VI., VII., and VIII., Part C., Sections I.,	Regulation 24, Part B (fkna Part B); Regulation 25, Part B (fkna

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		class II injection well facilities, and industrial waste; included state only provisions as SIP strengthening measures; clarified the applicability of requirements to newly classified ozone nonattainment areas; included requirements for motor vehicle materials and automotive coatings; expanded gasoline tank truck testing requirements.		II., and IV., and Part D, Section II.; Part D, Sections II., ; Part A, Sections I. and II.; Part C, Section I.; and Part B, Section IV.	Part C); Regulation 7, Part B (fkna Part D); Regulation 26, Part B (fkna Part E)

The Commission also made typographical, grammatical, and formatting corrections throughout the regulations.

Incorporation by Reference

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

Additional Considerations

These revisions are administrative in nature and, therefore, do not exceed or differ from the requirement of the federal act or rules. Therefore, § 25-7-110.5(5)(a) does not apply.

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 alternative 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.

Editor's Notes

History

Entire rule eff. 01/30/2009.

Rules I.A.1, XVII, XIX.L eff. 02/14/2011

Rules II.D, XII.D XII.H, XVII.D, XIX.M eff. 02/15/2013.

Rules II.B, VI.B.2.a.(i)(E), IX.A.12.a.(x), XVII XVIII, XIX.B, XIX.N eff. 04/14/2014.

Rules I.A.1., X.A, X.E, XII.A.3, XII.C.1, XII.C.2.a(ii)(B), XII.E, XII.F.3.d, XII.F.5.a, XII.G, XII.H.3-6, XII.I, XIII, XVI, XIX, XX, XX.O eff. 01/14/2017.

Entire rule eff. 12/30/2017.

Rules XVI, XIX, XX.Q eff. 09/14/2018.

Entire rule eff. 01/14/2019.

Entire rule eff. 02/14/2020.

Part D rules II, IV-VI, Part E, Part F rule T eff. 11/14/2020.

Part B rule IV.B 3, Part C rules I.1.A.1-1.A.11, I.O, Part D rules II.E.4, II.E.6-II.E.9, Part E rules II.A, III.A-III.B, Part F rule U eff. 02/14/2021.

Part D rules III.B, III.C.3.a, III.C.4, Part F rule V eff. 04/14/2021.

Part C rules I.A.6.b, I.L.1.a, I.L.1.b, I.L.1.c, I.L.2-I.L.5, Part D rule III.C.4.e.(i)(D)(3)(b), Part E rules II.A.1.c, II.A.2.e-f, II.A.3.p, II.A.4, II.A.4.b.(iii), II.A.4.e.(ii), II.A.4.g, II.A.5, II.A.6.a.(iii), II.A.6.b.(viii)(C)-(E), II.A.6.c.(ii), Part F rule W eff. 09/14/2021.

Part D rules I.E.3, I.J.1.g-k, II.A, II.B.1, II.B.2.f-j, II.B.3.b-d, II.C.1.d.(ii)-(v), II.C.2.a, II.C.2.b.(ii)(I), II.C.3.b, II.E.3.a.(iii), II.E.3.c-e, Table 3, II.E.4.a-b, II.E.4.d-g, Tables 4, 5, II.E.6.e, II.E.6.g, II.E.7.a.(iv), II.E.7.b, II.E.8.c, II.E.8.i.(iii)-(iv), II.F- II.I.1.b, III.C.3.a, III.C.3.d, III.C.4.e.(i)(D), III.D- III.F, V.B.1, V.C.2-V.D.3, VI.C.2.b.(x), Part F rule X eff. 01/30/2022.

Part D rules II.C.1.d.(ii)-(v), II.C.3.e repealed eff. 02/14/2022.

Part A rules I.A.1, I.B.1, I.B.2, II.A.13-17, II.C.1, Appendix A, Part B rules IV.B.2.a.(i)(D), IV.B.3.h, IV.C.2.d, IV.D.2.a.(i), IV.D.2.c, VI.A.2.a.(iii)(B), VI.B.7, VI.C.3, Part C rules I.A.3.a, I.L.4, I.N.7, I.O.2, I.P, II.D.2.a, II.E.3.b.(iii)(A)-(B), II.F.1, II.F.5.c.(i)(A)-(B), IV.A.4, IV.B.5.c.(iii)(A)-(B), IV.C, Part D rules I.A, I.B.7-33, I.D.1-I.D.3, I.E, I.E.2.c.(ix), I.E.3.a, I.F-I.H, I.J.1.a, I.J.1.h, I.J.2.a-I.J.2.b, I.K.1, I.K.2, I.L.1-I.L.2, I.L.7, I.M, II.B.5, II.C.5.a, II.H.1.c.(vii), II.H.3.c, II.H.3.f.(i), III.B.10, III.B.12, III.B.14, III.C.1, III.C.2, III.D, III.E, Part E rules I.D.1.b, I.D.4.a.(i)(B), I.D.4.c, I.D.5.d.(ii), I.D.5.e.(iv)(D), I.D.5.g.(iii), II, II.A.1, II.A.2.e, II.A.2.f, II.A.4, II.A.4.a.(v)- II.A.4.a.(vii), II.A.4.b.(ii), II.A.4.d, II.A.4.e, II.A.4.g.(iii), II.A.5.a.(iv), II.A.5.a.(v), II.A.5.b, II.A.6.a, II.A.6.b.(viii)(C)-(G), II.A.6.c.(ii), II.A.7.f.(iii), III.C, V.A.6.b, VI-VIII, Part F rule Y eff. 02/14/2023.

Entire rule, Part C rules Y, Z eff. 06/14/2023.