DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

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

5 CCR 1001-9

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

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

I. Applicability

I.A.

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

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

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

I.A.1.c. The provisions of Sections V., VI.B.1. and 2., VII.C., XVII., and XVIII. apply statewide. The provisions of Sections XVII., XVIII., and any other sections marked by (State Only) are not federally enforceable, unless otherwise identified.

I.A.2. REPEALED

I.A.3. REPEALED

I.B. Sources

I.B.1. New Sources

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

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

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

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

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

I.B.1.c. This Section I.B.1. does not apply to oil and gas operations subject to Section XII., stationary and portable engines subject to Section XVI., or natural gas actuated pneumatic controllers subject to Section XVIII.

I.B.2. Existing Sources

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

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

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

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

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

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

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

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

I.B.2.f. On or before October 30, 1990, all existing sources located in what was previously designated as the 1-hour ozone nonattainment or attainment maintenance area shall submit to the Division a report containing the following:

I.B.2.f.(i) A list of sources of volatile organic compound emissions located at the stationary source. The list shall include a description, potential emissions, and actual emissions of each source.

I.B.2.f.(ii) Identification of each source subject to a Division Reasonably Available Control Technology (RACT) determination, and when a request for that determination will be made.

I.B.2.f.(iii) The owner or operator's expected RACT for each source and a description of how compliance will be achieved. If a source is subject to RACT requirements as stated in previous versions of this regulation, the report need only specify how compliance will be achieved for any revised provisions of the regulation.

I.B.2.g. On or before October 30, 1991, all existing sources shall update and submit the report required under Section I.B.2.f.. The updated report shall describe in detail all actions taken to comply with the RACT requirements, and when those actions were taken.

I.B.2.h. This Section I.B.2. does not apply to oil and gas operations subject to Section XII., or stationary and portable engines subject to Section XVI.

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

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

I.E. Materials incorporated by reference in this regulation are available for public inspection during regular business hours at the Commission's Office at 4300 Cherry Creek Drive South, Denver, Colorado. The regulation incorporates the materials as they exist at the date of the promulgation of this regulation and does not include later amendments to or editions of the incorporated materials.

II. General Provisions

II.A. Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

II.A.17. “Volatile Organic Compound (VOC)” means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions, except those listed in Section II.B. as having negligible photochemical reactivity. VOC may be measured by a reference method, an equivalent method, an alternative method, or by procedures specified under 40 CFR Part 60. 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 Section XII.L. and natural gas emissions standards in Sections XVIII.C.1. and XVIII.C.2. are used as indicators for the volatile organic compound emission reduction measures in Sections XII.L., XVIII.C.1., and XVIII.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 Sections XVII. and XVIII.

II.C. General Emission Limitation

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

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

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

II.C.1.a.(ii) The potential to emit of such sources shall be based on design capacity or maximum production rate, whichever is greater, 8760 hours/year operation, and before add-on controls.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

II.C.2. New Sources

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

II.D. Alternative Control Plans and Test Methods

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

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

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

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

II.E. REPEALED

II.F. Provisions for Specific Processes

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

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

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

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

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

III.B. Transfer (excluding Petroleum Liquids)

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

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

IV. Storage of Highly Volatile Organic Compounds

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

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

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

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

V. Disposal of Volatile Organic Compounds

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

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

VI. Storage and Transfer of Petroleum Liquid

VI.A. General Requirements

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

VI.A.2. Definitions

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

VI.A.2.a. Repealed.

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

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

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

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

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

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

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

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

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

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

VI.B. Storage of Petroleum Liquid

VI.B.1. Exemptions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VI.B.2.c.(ii)(A)(1) Equipment

VI.B.2.c.(ii)(A)(1)(a) Drains: roof drains which are designed to empty directly into the stored product shall be provided with slotted-membrane fabric covers or equivalent covers which cover at least 90 percent of the area of the opening.

VI.B.2.c.(ii)(A)(1)(b) Openings: except for automatic bleeder vents, rim space vents, and leg sleeves, all openings shall be equipped with:

VI.B.2.c.(ii)(A)(1)(b)(I) Projections into the tank which remain below the liquid surface at all times; and

VI.B.2.c.(ii)(A)(1)(b)(II) Covers, seals, or lids.

VI.B.2.c.(ii)(A)(2) Procedures

VI.B.2.c.(ii)(A)(2)(a) Covers, seals and lids shall be kept closed except when the openings are in actual use.

VI.B.2.c.(ii)(A)(2)(b) Automatic bleeder vents shall be kept closed at all times except when the roof is floated off or landed on roof leg supports.

VI.B.2.c.(ii)(A)(2)(c) Rim vents shall be set to open at the manufacturer's recommended setting or, alternatively, only when the roof is being floated off the leg supports.

VI.B.2.c.(ii)(B) Inspections

The operator of an EFR tank subject to this Section VI.B.2.c. shall:

VI.B.2.c.(ii)(B)(1) Perform routine inspections at least once every six months in order to ensure compliance with Section VI.B.2.c.(ii)(B)(2). The inspections shall include a visual inspection of the secondary seal gap if equipped with a secondary seal.

VI.B.2.c.(ii)(B)(2) Ensure that all seal closure devices meet the following requirements:

VI.B.2.c.(ii)(B)(2)(a) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; and

VI.B.2.c.(ii)(B)(2)(b) The seal(s) are intact and uniformly in place around the circumference of the floating roof and the tank wall.

VI.B.2.c.(ii)(C) Records

VI.B.2.c.(ii)(C)(1) Operators shall:

VI.B.2.c.(ii)(C)(1)(a) Maintain records of the average monthly storage temperature, the Reid vapor pressure of the liquid and the type of liquid stored for all EFR tanks lacking secondary seals and receiving petroleum liquids with a true vapor pressure of 1.0 psi (7.0kPa) or greater; and

VI.B.2.c.(ii)(C)(1)(b) Maintain records of the results of the inspections required herein.

VI.B.2.c.(ii)(C)(2) Copies of all records specified by this Section VI.B.2.c.(ii)(C) shall be retained by the operator for a minimum of two years after the date on which the record was made.

VI.B.2.c.(iii) Secondary Seal Requirements

VI.B.2.c.(iii)(A) General

No owner or operator of an EFR tank (storing petroleum liquids) not specifically exempted in Section VI.B.2.c.(i)(B) shall store that petroleum liquid unless such vessel is equipped with a continuous secondary seal extending from the rim of the floating roof to the tank wall (i.e., a rim-mounted secondary seal).

VI.B.2.c.(iii)(B) Vapor-Mounted Seals

For EFR tanks required to have a secondary seal and which have a vapor-mounted primary seal:

VI.B.2.c.(iii)(B)(1) An annual inspection shall be made of the total gap area between the secondary seal and the wall of the tank in accordance with the method in VI.B.2.c.(iii)(B)(3).

VI.B.2.c.(iii)(B)(2) This total gap area shall not exceed 21.2 cm2/meter diameter (1.0 in2/ft. diameter).

VI.B.2.c.(iii)(B)(3) Method to determine gap area:

VI.B.2.c.(iii)(B)(3)(a) Physically measure the length and width of all gaps around the entire circumference of the secondary seal in each place where a 0.32 cm (1/8 in.) uniform diameter probe passes freely (without forcing or binding against the seal) between the seal and the tank wall; and,

VI.B.2.c.(iii)(B)(3)(b) Sum the area of the individual gaps.

VI.B.3. Storage of petroleum liquid in tanks of or less than 151,412 liters (40,000 gallons) capacity

VI.B.3.a. Tanks or containers used to store liquids with true vapor pressure at 20oC of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) at 20oC are exempt from the provisions of this Section VI.B.3.

VI.B.3.b. The owner or operator of storage tanks at a gasoline dispensing facility (service station) or other facility not addressed in Sections VI.C.2. or VI.C.3., which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and the vapors displaced from the storage tank during filling are processed by a vapor control system, if the tank:

VI.B.3.b.(i) Has a rated manufacturer's capacity of 2,082 liters (550 gallons) or more and was installed after November 7, 1973, (except for storage tanks below 550 gallon capacity used exclusively for agricultural use; however, these must have a submerged fill pipe), or

VI.B.3.b.(ii) Has a rated manufacturer's capacity of 7,571 liters (2,000 gallons) or more and was installed before November 7, 1973.

VI.B.3.b.(iii) A vapor balance system shall be deemed “approved” if its design and operation are in accordance with the applicable provisions of Appendices A and B.

VI.B.3.c. Tanks equipped with a submerged fill pipe shall meet the specifications of Appendix B.

VI.B.3.d. The vapor control system shall include one or more of the following:

VI.B.3.d.(i) A vapor-tight line from the storage tank to delivery vessel (i.e. an approved control system).

VI.B.3.d.(ii) A refrigerator-condensation system or equivalent designed to recover at least 90 percent by weight of the organic compounds in the displaced vapor.

VI.B.3.e. The owner or operator shall ensure that operating procedures are used so that gasoline cannot be transferred into the tank unless the vapor control system is in use.

VI.B.3.f. The vapor balance system shall meet the specifications of Appendix B.

VI.B.3.g. The vapor balance system and the vapor control system shall meet the requirements of Section XV.

VI.B.3.h. Control devices shall meet the applicable requirements, including recordkeeping, of Sections IX.A.3.a., b., c., and e., and IX.A.8.a. and b.

VI.B.3.i. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 shall be used to determine the efficiency of control devices.

VI.C. Transfer of Petroleum Liquid

VI.C.1. Exemptions

Transfer operations involving petroleum liquid with true vapor pressures at 20oC of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) shall be exempt from the provisions of this Section VI.C.

VI.C.2. Loading Facilities Classified as Terminals

VI.C.2.a. A terminal is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of more than 76,000 liters of gasoline (20,000 gallons), which is loaded directly into transport vehicles. A rolling, 30-day average of throughput shall be used to determine the applicability of this Section VI.C.2.

VI.C.2.b. The owner or operator of a terminal subject to this section shall equip the terminal with proper loading equipment and shall follow the loading procedures listed:

VI.C.2.b.(i) Install dry-break loading couplings to prevent petroleum liquid loss during uncoupling from vehicles.

VI.C.2.b.(ii) Install a vapor collection and disposal system which gathers vapor transferred from vehicles being loaded. The system shall include devices to prevent the release of vapor from vapor recovery hoses not in use.

VI.C.2.b.(iii) Use operating procedures to ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

VI.C.2.b.(iv) Provide for the prevention of overfilling of transport vehicles with loading pump shut-offs, set stop meters, or comparable equipment.

VI.C.2.b.(v) Operate all recovery and disposal equipment at a back pressure less than the pressure relief valve setting of transport vehicles.

VI.C.2.b.(vi) Prevent the release of petroleum liquid on the ground from transport vehicles. Provision shall be made to remove any undelivered petroleum liquid with closed drainage devices.

VI.C.2.b.(vii) Maintain and operate final recovery and disposal equipment or devices in the vapor control system (i.e., control devices) so as to emit no more than 80 milligrams of volatile organic compounds per liter of gasoline being loaded. Such disposal devices shall be approved by the Division.

VI.C.2.b.(viii) Prevent loading of petroleum liquid into transport vehicles which do not have valid leak-tight certification as required in Section VI.D. No truck shall be loaded unless a valid certification sticker is displayed, or a certification letter is carried in the truck.

VI.C.2.b.(ix) Follow all control procedures to prevent leaks as specified in Section XV.

VI.C.2.c. Control devices shall meet the applicable requirements, including recordkeeping of Sections IX.A.3.a., b., c., and e., and IX.A.8.a. and b.

VI.C.2.d. The applicable methods of 40 CFR 60. 503, or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 shall be used to determine the efficiency of control devices.

VI.C.2.e. The method set forth in Appendix A of EPA-450/2-77-026, “Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals” shall be used to test emission points other than control devices.

VI.C.3. Loading Facilities Classified as Bulk Plants

VI.C.3.a. A bulk plant is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of 76,000 liters of gasoline (20,000 gallons) or less, which is loaded directly into transport trucks. (As used herein, "bulk plant" does not include service stations nor separate operations within petroleum liquid distribution facilities which pump only into fuel tanks fueling motor vehicles. Both such operations are regulated by Section VI.B.3.). A rolling 30-day average of throughput shall be used to determine the applicability of this regulation.

VI.C.3.b. The owner or operator of a bulk storage plant subject to this section shall install an approved vapor balance system to return vapors to the incoming transport trucks during the filling of tanks controlled under Section VI.B.3. (A vapor balance system shall be deemed "approved" if its design and operation is in accord with the provisions of Appendix C.)

VI.C.3.c. The owner or operator of a bulk plant which serves storage tanks which are required to collect and recover vapor as prescribed in Section VI.B.3. shall:

VI.C.3.c.(i) Install and operate vapor collection and return equipment on any transport vehicles used to deliver to controlled tanks, and

VI.C.3.c.(ii) Install and operate vapor collection and return equipment at loading facilities to collect vapors during loading of tank compartments of outbound transport trucks and return these vapors to the bulk plant storage tanks, using an approved vapor balance system.

VI.C.3.c.(iii) Assure that transport trucks and loading facilities conform to the applicable provisions of Sections VI.C.2. and VI.C.4.

VI.C.3.d. The owner or operator of a bulk plant which serves only storage tanks exempted from the provisions of Section VI.B.3.b. by reason of their small size or location in an attainment area shall load outbound transport trucks using equipment that provides for top loading of the petroleum liquid into the vehicle tank compartments through an extended fill tube which reaches within 15.24 cm (6 in.) of the bottom of the tank compartment.

VI.C.3.e. The owner or operator of a bulk plant subject to this section shall ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

VI.C.3.f. The owner or operator of a bulk plant subject to this section shall follow all procedures to prevent leaks as specified in Section XV.

VI.C.4. Transport Vehicles

VI.C.4.a. Rail cars shall be loaded only at facilities which allow for the following:

VI.C.4.a.(i) A submerged fill pipe which reaches within 15.24 cm (6 in.) of the bottom of the tank.

VI.C.4.a.(ii) Vapor collection and/or disposal equipment designated and operated to recover vapors displaced during the loading of the rail car.

VI.C.4.a.(iii) A vapor-tight seal around the tank car hatch and the loading equipment.

VI.C.4.b. The owner or operator of petroleum transport trucks which serve locations required to be equipped with vapor recovery equipment shall load only at facilities capable of disposing of collected vapors. The owner or operator shall assure that such vehicles possess the proper equipment and that work practices are followed so that:

VI.C.4.b.(i) Dry-break loading and unloading nozzles are used and are compatible with those required at loading facilities.

VI.C.4.b.(ii) Vapor recovery hoses are connected at all times during unloading or loading of petroleum distillate.

VI.C.4.b.(iii) Transport trailers and vehicle tanks are operated and maintained to prevent detectable hydrocarbon vapor loss during loading, transport and delivery.

VI.C.4.b.(iv) Compartment dome lids are closed and locked during transfers of petroleum liquid. Such lids may be opened for the purpose of certifying the accuracy of a delivery only prior to and after such delivery.

VI.C.4.b.(v) Hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loading or unloading.

VI.D. Control of Volatile Organic Compound Leaks from Gasoline Transport Trucks

VI.D.1. General Provisions

VI.D.1.a. Applicability

This section is applicable to all gasoline transport trucks equipped for gasoline vapor collection which receive or dispense gasoline at terminals, bulk plants, or gasoline dispensing facilities located in the nonattainment areas.

VI.D.1.b. Definitions

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

VI.D.1.b.(i) "Gasoline Transport Truck" means a tank truck or tank trailer equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants, or gasoline terminals.

VI.D.1.b.(ii) "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into a vessel being unloaded or into a vapor control system or vapor holding tank.

VI.D.1.b.(iii) "Vapor Control System" means a system that is designed to control the release of volatile organic compounds displaced from a vessel during transfer of gasoline.

VI.D.2. Provisions for Specific Processes

VI.D.2.a. No terminal operator, when monitoring the gasoline loading operation and no owner or operator of a gasoline transport truck shall allow a gasoline transport truck subject to this Section VI.D. to be filled with a VOC with Reid Vapor Pressure of 4.0 or greater unless the gasoline tank truck:

VI.D.2.a.(i) Is tested annually according to the test procedure referenced in Appendix E. Testing shall be completed prior to the onset of the summer ozone season (test October through April). In addition, the visual inspection detailed in Appendix E, paragraph B, shall be performed at least once every six months. Trucks which have not been previously certified (new gasoline transport trucks) may be tested May through September as set forth in Section VI.D.4.d.(iv).

VI.D.2.a.(ii) Sustains a combined absolute pressure change of no more than 5.6 torr (3 inches of H2O) in five-minute test periods when pressurized to a gauge pressure of 33.6 torr (18 inches of H2O), then evacuated to a gauge pressure of minus 11.2 torr (minus 6 inches of H2O), during the testing required in Section VI.D.2.a.(i) (i.e., the sum of the absolute pressure change determined by the pressure test plus the absolute pressure change determined by the vacuum test shall not exceed 3 inches of water); and

VI.D.2.a.(ii)(A) Sustains a leak rate of no more than 5.6 torr (3 inches H2O) in five minutes when the internal vapor valves are tested according to procedures in Appendix E, paragraph E

VI.D.2.a.(ii)(B) Passes a retest within twenty (20) days if it does not meet the criteria of Section VI.D.2.a.(ii) and Section VI.D.2.a.(ii)(A).

VI.D.2.a.(ii)(C) At all times carries an unexpired certification sticker (pursuant to Sections VI.D.4.c. and VI.D.4.d.).

VI.D.2.b. Monitoring

VI.D.2.b.(i) The Division may, at any time, monitor a gasoline tank truck vapor collection system, or vapor control system, by the method referenced in Section VI.D.3.c to confirm continued compliance with Section VI.D.2.a..

VI.D.2.b.(ii) Within fifteen (15) days after an exceedance is detected a tank shall pass:

VI.D.2.b.(ii)(A) A pressure/vacuum test per Appendix E; or

VI.D.2.b.(ii)(B) A test with combustible gas detector using procedures referenced in Section VI.D.3.c. such that no leak over 60% of the propane lower explosive limit (LEL) exists.

VI.D.3. Testing and Monitoring

VI.D.3.a. The owner or operator of a gasoline transport truck shall at their own expense, demonstrate compliance with Section VI.D.2, by methods of Appendix E. All tests shall be made by, or under the direction of, a person qualified by training and/or experience in the field of air pollution testing or gasoline transport truck maintenance.

VI.D.3.b. The owner or operator of a gasoline transport truck subject to this regulation must notify the Division of the date and location of a certification test at least forty-eight (48) hours before an anticipated test date, except that for the first truck tested by a given transport company and for the first test by a given testing facility, five (5) days' notice must be given the Division: or alternatively, a designated individual within the Division may orally waive the notice requirements and allow a shorter notice period before the test.

VI.D.3.c. Monitoring to confirm the continuing existence of leak tight conditions shall be consistent with the procedures described in Appendix B. of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," EPA-450/2-78-051.

VI.D.4. Recordkeeping and Reporting

VI.D.4.a. The owner or operator of a gasoline transport truck subject to this Section VI.D. shall maintain records of all certification testing and repairs. The records shall identify the gasoline transport truck, the date of the test or repairs and, if applicable, the type of repair and the date of retest. The written record shall include entries of any pre-test repairs, adjustments, or modifications. These shall also include the part name, number, and vendor name of any part removed and of any part installed. The records shall be maintained in legible, readily available form for at least two (2) years after the date the testing or repair was completed and shall be made available to the Division for inspection upon request.

VI.D.4.b. The records of certification tests required by Section VI.D.2.a. shall, as a minimum, contain all of the following entries:

VI.D.4.b.(i) The gasoline transport truck/tank identification number;

VI.D.4.b.(ii) The following data for each test trial:

VI.D.4.b.(ii)(A) The initial test pressure and the time of the reading.

VI.D.4.b.(ii)(B) The final test pressure and the time of the reading.

VI.D.4.b.(ii)(C) The initial test vacuum and the time of the reading.

VI.D.4.b.(ii)(D) The final test vacuum and the time of the reading.

VI.D.4.b.(ii)(E) For the vapor valve test, the initial test-pressure and time of reading; and

VI.D.4.b.(ii)(F) The final test-pressure and the time of the reading.

VI.D.4.b.(iii) The size of each of the compartments within the tank and whether such compartment was manifolded or was tested separately during pressure and vacuum tests.

VI.D.4.b.(iv) At the top of each report page shall be the company name and the date and location of the test results recorded on that page; and

VI.D.4.b.(v) Name and title of the person conducting the test.

VI.D.4.c. The owner or operator of a gasoline transport truck subject to this regulation must annually certify to the Division that the gasoline transport truck has been tested by an applicable method referenced in Section VI.D.3. The application for certification shall include:

VI.D.4.c.(i) The name and address of the company and the name and telephone number of responsible company representative over whose signature the certification is submitted; and,

VI.D.4.c.(ii) A copy of the information recorded to comply with Section VI.D.4.b.

VI.D.4.d. Certification

VI.D.4.d.(i) Except as stated in Sections VI.D.4.d.(ii), (iii), and (iv), upon receipt of an application for certification that meets the requirements, the Division shall issue a sticker and a letter of certification to be valid for 380 days after the most recent, successfully completed pressure/vacuum test, except that the expiration date shall not fall within the months of May through September. The certification shall be valid for less than 380 days if necessary to remain within the allowable test period of October through April.

VI.D.4.d.(ii) Owners or operators of gasoline transport trucks with certificates that expire May 1, 1990 (1991) through July 31, 1990 (1991) shall renew their certificates in March or April, 1990 (1991).

VI.D.4.d.(iii) Owners or operators of gasoline transport trucks with certificates that expire August 1, 1990 (1991) through September 30, 1990 (1991) shall renew their certificates in October or November 1990 (1991). Certificates which expire August 1, 1990 (1991) through September 30, 1990 (1991) shall be valid until November 30, 1990 (1991).

VI.D.4.d.(iv) Owners or operators of previously uncertified trucks (new gasoline transport trucks) subject to this section may obtain initial certification May 1 through September 30, if necessary. Certification for such trucks certified May 1 through July 31 shall be valid for 270 days. Certification for such trucks certified August 1 through September 30 shall be valid for 430 days. All expiration dates for such certificates shall fall within the allowable testing period of October through April.

VI.D.4.d.(v) This certification shall be revoked if monitoring detects an exceedance which is not corrected within fifteen (15) days of initial detection, or if the exceedence is judged so severe as to warrant immediate revocation (i.e., no seal is maintained during transfer).

VI.D.4.e. The certification letter shall be kept with the tank or at the transport company office at all times and shall be shown to Division personnel upon their request. Copies of all records and reports required by the provisions of this Section VI.D. shall be made available to the Division upon oral or written request. The tank shall at all times prominently display a valid sticker when containing gasoline in the ozone nonattainment area.

VII. Crude Oil

VII.A. General Exemptions

VII.A.1. Storage tanks of 151,412 liters (40,000 gallons) or less used to store crude oil is exempt from the provisions of this section.

VII.A.2. Storage tanks with capacities of less than 1,590 cubic meters (10,000 barrels) used to store crude oil and condensate prior to lease custody transfer are exempt from the provisions of this Regulation Number 7 other than Sections XII. and XVII.

VII.B. Equipment

Pumps and compressors handling crude oil shall be subject to the provisions of Section VI.A.

VII.C. Storage

Except as provided in Section VII.A.2., crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Sections VI.B.1.b. and VI.B.2.

VIII. Petroleum Processing and Refining

VIII.A. Wastewater (Oil/Water) Separators

VIII.A.1. Definitions

VIII.A.1.a. "Forebays" mean the primary sections of a wastewater separator.

VIII.A.1.b. "Wastewater (oil/water) separator" means any device or piece of equipment which utilizes the difference in density between oil and water to remove oil and associated chemicals from water, or any device, such as a flocculation tank, clarifier, etc., which removes petroleum derived compounds from wastewater.

VIII.A.2. The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall:

VIII.A.2.a. Equip the forebays and separator sections of the wastewater separators with one or more of the following emission control devices, ensuring that such device is properly installed, in good working order and properly maintained:

VIII.A.2.a.(i) A solid cover with all openings sealed and the liquid contents totally enclosed.

VIII.A.2.a.(ii) A pontoon-type or double-deck type floating roof, or internal floating cover. The floating roof or cover must rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and the wall(s) of the compartment.

VIII.A.2.a.(iii) A vapor recovery system consisting of a vapor gathering device capable of collecting the volatile organic compound vapors discharged and a vapor disposal device capable of processing such volatile organic vapors so as to prevent their emission into the atmosphere.

VIII.A.2.a.(iii)(A) Control devices shall meet the applicable requirements, including recordkeeping, of Sections IX.A.3.a., b., c., and e., and IX.A.8.a. and b.

VIII.A.2.a.(iii)(B) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 shall be used to determine the efficiency of control devices.

VIII.A.2.b. Equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized.

VIII.B. Emissions from Petroleum Refineries

VIII.B.1. Definitions

VIII.B.1.a. "Firebox" means the chamber or compartment of a boiler or furnace in which materials are burned but does not mean the combustion chamber of an incinerator.

VIII.B.1.b. "Turnaround" means the procedure of shutting a refinery unit down after a run to do necessary maintenance and repair work and then putting the unit back on stream.

VIII.B.2. Process unit turnarounds

The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for:

VIII.B.2.a. Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency;

VIII.B.2.b. No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and

VIII.B.2.c. Recordkeeping of the following items. Records shall be kept for at least two years and shall be made available to the Division for review upon request.

VIII.B.2.c.(i) Every date that each process unit is shut down,

VIII.B.2.c.(ii) The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere, and

VIII.B.2.c.(iii) The approximate total quantity of volatile organic compounds emitted to the atmosphere.

VIII.B.3. Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

VIII.B.4. Vacuum-Producing Systems

VIII.B.4.a. The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensible volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by:

VIII.B.4.a.(i) Venting the noncondensible vapors to a flare or other combustion device, or,

VIII.B.4.a.(ii) Compressing the vapors and adding them to the refinery fuel gas.

VIII.B.5. All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access.

VIII.B.6. Control devices shall meet the applicable requirements, including recordkeeping, of Sections IX.A.3.a., b., c., and e., and IX.A.8.a. and b.

VIII.B.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60, shall be used to determine the efficiency of control devices.

VIII.C. Petroleum Refinery Equipment Leaks

VIII.C.1. Definitions

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

VIII.C.1.a. "Accessible Component" means a component which can be reached, if necessary, by safe and proper use of portable ladders such as are acceptable to OSHA, as well as by built-in ladders and walkways. "Accessible" also includes components which can be reached by the safe use of an extension on the monitoring probe.

VIII.C.1.b. "Component" means any piece of equipment, which has the potential to leak volatile organic compounds when tested in the manner described in Section VIII.C.3. These sources include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open ended pipes. Excluded from these sources are valves which are not externally regulated.

VIII.C.1.c. "Gaseous Service" means equipment which processes, transfers or contains a volatile organic compound or mixture of volatile organic compounds in the gaseous phase.

VIII.C.1.d. "In Heavy VOC Liquid Service" means that the piece of equipment is not in gaseous service or in light VOC liquid service.

VIII.C.1.e. "In Light Liquid VOC Service" Equipment is in light liquid service if the following conditions apply:

VIII.C.1.e.(i) the true vapor pressure of one or more of the components is greater than 0.3 kPa at 20°C. True vapor pressures may be obtained from standard reference texts or may be determined by ASTM D-2879.

VIII.C.1.e.(ii) the total concentration of the pure components have a true vapor pressure greater than 0.3 kPa at 20°C, is equal to or greater than 20 percent by weight; and

VIII.C.1.e.(iii) the fluid is a liquid at operating conditions.

VIII.C.1.f. "Refinery Unit" means a set of components which are a part of a basic process operation, such as, distillation, hydrotreating, cracking, or reforming of hydrocarbons.

VIII.C.1.g. "Water Draw" means a routinely used valve or system employing a valve which allows non-VOC material (usually water) to be separated from VOC.

VIII.C.2. Provisions for Specific Processes

VIII.C.2.a. The owner or operator of a petroleum refinery complex subject to this regulation shall:

VIII.C.2.a.(i) Develop a monitoring program consistent with the provisions in Section VIII.C.3.

VIII.C.2.a.(ii) Conduct a monitoring program consistent with the provisions in Section VIII.C.4.a.

VIII.C.2.a.(iii) Record all leaking components which have a VOC concentration exceeding 10,000 ppm when tested according to Section VIII.C.3., and place an identifying tag on each component consistent with the provisions in Section VIII.C.4.a.(iii).

VIII.C.2.a.(iv) Repair and retest leaking components, as defined in Section VIII.C.2.a.(iii), as soon as possible, but no later than fifteen (15) days after the leak is found, excepting those specified in Sections VIII.C.2.a.(v) and VIII.C.2.a.(vi).

VIII.C.2.a.(v) Identify all leaking components as defined in Section VIII.C.2.a.(iii), which cannot be repaired until the unit is shut down for turnaround, and repair and retest as in Section VIII.C.2.a.(iv) when the unit is back on stream.

VIII.C.2.a.(vi) When a component leak cannot be fixed within fifteen (15) working days solely because parts are not available, the following shall be noted in an “awaiting parts log:”

VIII.C.2.a.(vi)(A)component identification and tag number

VIII.C.2.a.(vi)(B)date part was ordered

VIII.C.2.a.(vi)(C) date part was received

VIII.C.2.a.(vi)(D) date repair was made

VIII.C.2.b. Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use.

VIII.C.2.c. The Division, at its discretion, may require early unit turnaround based on the number and severity of tagged leaks awaiting turnaround provided:

VIII.C.2.c.(i) The requirement does not exceed reasonable available control technology due to cost per ton of emissions reduction achieved by the early turnaround or other reasonable analysis.

VIII.C.2.c.(ii) The Division provides the owner or operator of a petroleum refinery with written notification at least 180 days before requiring an early turnaround. The owner or operator will have 30 days from the date of the Division's notification to contest the requirement by submitting a demonstration that the requirement is beyond reasonable available control technology. If no demonstration is made, it will be assumed the requirement is reasonable. If a demonstration is submitted by the owner or operator, the Division will either approve the demonstration or disapprove the demonstration with a justification regarding the disapproval within 30 days of the date the demonstration is submitted to the Division.

VIII.C.2.c.(iii) The requirement is not contested by the owner or operator. Should the requirement be contested, the requirement for early unit turnaround will be delayed until 180 days after the demonstration discussed in Section VIII.C.2.c.(ii) is disapproved by the Division.

VIII.C.2.d. Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly.

VIII.C.3. Testing and Monitoring Procedures

Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60. The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound.

VIII.C.4. Monitoring, Recordkeeping, Reporting

VIII.C.4.a. Monitoring

VIII.C.4.a.(i) The owner or operator of a petroleum refinery subject to this regulation shall conduct a monitoring program consistent with the following provisions:

VIII.C.4.a.(i)(A) Monitor yearly by the method referenced in Section VIII.C.3., all:

VIII.C.4.a.(i)(A)(1) Pump seals; and

VIII.C.4.a.(i)(A)(2) Piping valves in light liquid VOC service; and

VIII.C.4.a.(i)(A)(3) Process drains; and

VIII.C.4.a.(i)(A)(4) Heat-exchanger body flanges; and

VIII.C.4.a.(i)(A)(5) Other accessible flanges in VOC service.

VIII.C.4.a.(i)(A)(6) Components in heavy liquid VOC service are exempt from requirements of this Section VIII.C.4.a.(i)(A).

VIII.C.4.a.(i)(B) Monitor quarterly by the method referenced in Section VIII.C.3., all:

VIII.C.4.a.(i)(B)(1) Compressor seals; and

VIII.C.4.a.(i)(B)(2) Piping valves in gaseous service; and

VIII.C.4.a.(i)(B)(3) Pressure relief valves in gaseous service.

VIII.C.4.a.(i)(C) Monitor at least weekly by visual methods all pump seals.

VIII.C.4.a.(i)(D) Monitor within 24 hours with a VOC detector and make record of any component from which VOC liquids are observed leaking.

VIII.C.4.a.(i)(E) Components in heavy liquid VOC service shall be monitored by the method referenced in Section VIII.C.3. within five days if evidence of a potential leak is found by visual, audible, olfactory, or any other detectable method.

VIII.C.4.a.(ii) Inaccessible valves and flanges shall be monitored annually or, as a minimum, at unit shutdown using the procedures of VIII.C.2.a.(v). Pressure relief devices which are connected to an operating flare header or vapor recovery device, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Section VIII.C.4.a.(i).

VIII.C.4.a.(iii) The owner or operator of a petroleum refinery, upon the detection of a leaking component as defined in Section VIII.C.2.a.(iii), shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired. In addition, the owner or operator shall log the leak (including those leaks immediately repaired), per the requirements of Sections VIII.C.4.b.(i) through (iii).

VIII.C.4.b. Recordkeeping

VIII.C.4.b.(i) The owner or operator of a petroleum refinery shall maintain a leaking components monitoring log which shall contain at a minimum, the following data:

VIII.C.4.b.(i)(A) The name of the process unit where the component is located.

VIII.C.4.b.(i)(B) The type of component (e.g., valve, seal).

VIII.C.4.b.(i)(C) The tag number of the component.

VIII.C.4.b.(i)(D) The date on which a leaking component is discovered.

VIII.C.4.b.(i)(E) The date on which a leaking component is repaired.

VIII.C.4.b.(i)(F) The date and instrument reading found during the recheck procedure subsequent to repairing a leaking component.

VIII.C.4.b.(i)(G) A record of the calibration of the monitoring instrument.

VIII.C.4.b.(i)(H) Those leaks that cannot be repaired until turnaround.

VIII.C.4.b.(i)(I) The total number of components checked and the total number of components found leaking.

VIII.C.4.b.(i)(J) The total number of components subject to Section VIII.C.2.a.(v) which upon retest were still leaking as defined in Section VIII.C.3.

VIII.C.4.b.(ii) Copies of the monitoring log shall be retained by the owner or operator for a minimum of two (2) years after the date on which the record was made or report prepared.

VIII.C.4.b.(iii) Copies of the monitoring log shall be made available to the Division upon oral or written request.

VIII.C.4.c. Reporting

The owner or operator of a petroleum refinery, upon the completion of each yearly and/or quarterly monitoring procedure, shall:

VIII.C.4.c.(i) Submit a report to the Division by the 15th day of February, May, August, and November that lists all leaking components that were located during the previous three (3) calendar months (quarter), but not repaired within fifteen (15) working days, all leaking components awaiting unit turnaround, the total number of components inspected, and the total number of components found leaking.

VIII.C.4.c.(ii) Submit a signed statement with the report attesting to the fact that, with the exception to those leaking components listed in Section VIII.C.4.b.(i)(H), all monitoring and repairs were performed as stipulated in the monitoring program.

IX. Surface Coating Operations

IX.A. General Provisions

IX.A.1. Definitions

IX.A.1.a. “Coating” means a protective, functional or decorative film applied in a thin layer to a surface. This term often applies to paints such as lacquers or enamels, but is also used to refer to films applied to paper, plastics, or foils.

IX.A.1.b. “Coating Applicator” means an apparatus used to apply a surface coating.

IX.A.1.c. “Coating Line” means an operation which includes both (1) a coating applicator and (2) device(s) and/or area(s) to accomplish one or more of the following processes: flash-off, drying, curing, heat-setting and/or polymerization.

IX.A.1.d. "Coating Solids" means that portion of a surface coating, which remains after volatile components have escaped.

IX.A.1.e. "Final Repair Application" means that application of surface coating specifically intended to repair damage and imperfections in existing surface coats.

IX.A.1.f. "Finished Coating Solids" means those coating-solids that remain on a coated substance after completion of all production processes.

IX.A.1.g. "Flash-off Area" means the space between the application area and the oven.

IX.A.1.h. "Prime Coat" (also termed "primer") means the first film of coating applied in a multiple-coat operation.

IX.A.1.i. "Single Coat" means a single film of coating applied directly to the metal substrate, omitting the primer application.

IX.A.1.j. "Surface Coating" means a liquid, liquefiable, or mastic composition which is converted to a solid (or semi-solid) protective, decorative, or adherent film or deposit after application as a thin layer or by impregnation.

In a machine which has both coating and printing units, all units shall be considered as performing a printing operation. Such a machine is subject to the standards governing graphic arts, and thus is not covered by coating standards.

IX.A.1.k. "Surface Coating Oven" means a chamber within which heat is used to bake, cure, polymerize, and/or dry a surface coating.

IX.A.1.l. "Topcoat" means the final film of coating applied in a multiple-coat operation.

IX.A.2. Abbreviations

IX.A.2.a. Kg/lc shall be the abbreviation for: kilograms of solvent VOC per liter of coating (minus water and "exempt" solvents, as defined in Section II.B.).

IX.A.2.b. Lb/gc shall be the abbreviation for: (avoirdupois) pounds of solvent VOC per gallon of coating (minus water and "exempt" solvents, as defined in Section II.B.).

IX.A.3. Test Methods and Procedures

IX.A.3.a. The owner or operator of any VOC source required to comply with this section shall, at their own expense, demonstrate compliance using EPA reference method 24 of 40 CFR Part 60 for surface coatings, and reference method 25 and reference methods I through 4 for add-on controls.

IX.A.3.b. The test protocol should be in accordance with the requirements of the Air Pollution Control Division Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No test shall be conducted without prior approval from the Division.

IX.A.3.c. The Division may use independent tests to verify test data submitted by the source operator or owner. The test methods shall be those listed in Section IX.A.3.a. and the Division test results shall take precedence.

IX.A.3.d. The Division may accept, instead of the testing required in this section, a certification by the manufacturer of the composition of the coatings if supported by actual batch formulation records. The owner or operator of the VOC source required to comply with this section shall obtain certification from the coating manufacturer(s) that the test method(s) used for determination of VOC content meet the requirements specified in Section IX.A.3.a. The owner or operator shall have this certification readily available to Division personnel, in order to allow the results to be used in the daily compliance calculations specified in Section IX.A.10.

IX.A.3.e. The performance of add-on control device equipment shall be established with the required test methods of IX.A.3.a. at equipment startup, and after major modification to the control equipment. Baseline operating parameters shall be established during the satisfactory (i.e. in-compliance) operation of the control equipment, including operation during all anticipated ranges of process throughput. During subsequent process operation, the owner or operator shall maintain the operating conditions of the add-on controls as close to these baseline conditions as possible. If serious operational problems with an add-on control system are evidenced from the daily monitoring required by Section IX.A.8.b. (such problems may be indicated by changes from baseline conditions), repeat performance tests may be required by the Division, as necessary.

IX.A.4. Sampling

To determine compliance with applicable surface coating standards, samples shall be taken from the coating as freshly delivered to the reservoir of the coating applicator.

IX.A.5. Alternative compliance methods for processes and operations

For each process specified in Sections IX.B. through IX.N. the emission limits designated for that process shall be achieved by::

IX.A.5.a. Use of coatings with proportions of VOC less than or equal to the maximums specified by the applicable section of this regulation; or

IX.A.5.b. Use of the specified equipment and procedures prescribed by the applicable section of this regulation; or

IX.A.5.c. Use of an alternative means of control which satisfies the requirements of Section IX.A.5.e., IX.A.5.f., and Section II.D.; or

IX.A.5.d. Use of crossline averaging. The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met. In addition, the following requirements apply:

IX.A.5.d.(i) The actual reduction shall be equivalent to the actual reduction that would be achieved on a line-by-line basis.

IX.A.5.d.(ii) Credit shall not be received for downtime, however, credit is allowed for enforceable production limits.

IX.A.5.d.(iii) Crossline averaging shall be used only across lines in the same control technique guidance group.

IX.A.5.d.(iv) The emission trading policy shall be met on a daily weighted average.

IX.A.5.d.(v) Sources subject to best available control technology (BACT) and lowest achievable emission rate (LAER) requirements shall not use cross line averaging.

IX.A.5.d.(vi) VOC emissions shall be expressed as lbs/gallons solids to determine reduction over baseline (lb VOC/lb solids for graphic arts).

IX.A.5.d.(vii) Organisol and plastisol coatings shall not be used to bubble emissions from vinyl surface or automobile topcoating operations.

IX.A.5.d.(viii) Before crossline averaging may be used, the control methodology shall be approved as a revision to the State Implementation Plan.

IX.A.5.e. The design, operation and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Unless the capture system meets the requirements for a total enclosure as specified in the New Source Performance Standard for the Magnetic Tape Manufacturing Industry, 53FR38892, October 3, 1988, or unless Division approved material balance techniques are used to adequately determine overall VOC capture and destruction/recovery efficiency, the efficiency of the capture system shall be determined by test methods approved as a revision to the State Implementation Plan. Testing for capture efficiency shall be performed on a case-by-case basis as required by the Division. The requirements of Sections IX.A.3.e. and IX.A.8.b. shall apply to the capture and control device system. When capture and control device efficiency must be independently determined, the overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

IX.A.5.f. Sources which use add-on controls, crossline averaging, or an approved alternative control strategy instead of low solvent technology to meet the applicable emission limit shall meet the equivalent VOC emission limit, on the basis of solids applied (lb VOC/gal solids applied, or lb VOC/lb solids applied, for graphic arts sources). Appendix F sets forth the procedure for converting emission limits and lists equivalent limits for various coating operations.

IX.A.5.g. Owners or operators of sources which use a carbon adsorption system shall provide for the proper disposal or reuse of all VOC recovered.

IX.A.6. Exemptions

IX.A.6.a. The requirements of this Section IX. do not apply to sources used exclusively for chemical or physical analysis or determination of product quality and commercial acceptance, provided;;

IX.A.6.a.(i) the operation of the source is not an integral part of the production process; and

IX.A.6.a.(ii) the emissions from the source do not exceed 363 kilograms (800 lbs.) in any calendar month; and

IX.A.6.a.(iii) the exemption is approved in writing by the Division.

IX.A.6.b. The requirements of Sections IX.C., D., E., F., G., H., I., L. and M. are not applicable to sources whose actual emissions, including fugitive emissions, before add-on controls, are less than 6.8 kilograms (15 lbs.) per day and less than 1.4 kilograms (3 lbs.) per hour. Emissions from all sources within the same control technique guidance group shall be totaled to determine actual emissions.

IX.A.7. Fugitive emission control

IX.A.7.a. Control techniques and work practices shall be implemented at all times to reduce VOC emissions from fugitive sources. Control techniques and work practices include, but are not limited to:

IX.A.7.a.(i) tight-fitting covers for open tanks;

IX.A.7.a.(ii) covered containers for solvent wiping cloths;

IX.A.7.a.(iii) proper disposal of dirty cleanup solvent.

IX.A.7.b. Emissions of organic material released during clean-up operations, disposal, and other fugitive emissions shall be included when determining total emissions, unless the source owner or operator documents that the VOCs are collected and disposed of in a manner that prevents evaporation to the atmosphere.

IX.A.8. Recordkeeping, Reporting, and Monitoring

IX.A.8.a. If add-on control equipment is used, continuous monitors of the following parameters shall be installed, calibrated, and operated at all times that the associated control equipment is operating:

IX.A.8.a.(i) exhaust gas temperature of all incinerators;

IX.A.8.a.(ii) temperature rise across a catalytic incineration bed;

IX.A.8.a.(iii) breakthrough of VOC on a carbon adsorption unit;

IX.A.8.a.(iv) any other monitoring and/or recording device, maintenance and/or control-media-replacement schedule(s) specified on a case-by-case basis by the Division.

IX.A.8.b. If add-on control equipment is used, in addition to the requirements of Section IX.A.8.a., the following information and any other necessary information, as determined applicable for each source by the Division, shall be monitored and recorded daily in order to assure continuous compliance. The substitution of continuous recordings for daily recording may be allowed by the Division.

IX.A.8.b.(i) For the capture system: fan power use, duct flow, duct pressure.

IX.A.8.b.(ii) For carbon adsorbers: bed temperature, bed vacuum pressure, pressure at the vacuum pump, accumulated time of operation, concentration of VOC in the outlet gas, solvent recovery.

IX.A.8.b.(iii) For refrigeration systems: compressor discharge and suction pressures, condenser fluid temperature, solvent recovery.

IX.A.8.b.(iv) For incinerator systems: exhaust gas temperature, temperature rise across a catalytic incinerator bed, flame temperature, accumulated time of incinerator.

IX.A.8.c. Recordkeeping procedures shall follow the guidance in “Recordkeeping Guidance Document for Surface Coating Operations and the Graphic Arts Industry,” July 1989, EPA 340/1-88-003.

IX.A.9. Required and Prohibited Acts

IX.A.9.a. No owner or operator of a source of VOCs subject to this section shall operate, cause, allow or permit the operation of the source, unless:

IX.A.9.a.(1) For each category of surface coating as specified in Sections IX.B. through IX.M., the owner or operator of a surface coating line or facility subject to that section does not cause, allow or permit the discharge into the atmosphere of any VOCs in excess of the specified emission limit, calculated as delivered to the coating applicator or as applied to the substrate, whichever is greater.

IX.A.10. Compliance Calculation Procedures

IX.A.10.a. Compliance with this section shall be determined on a daily basis. Sources may request a revision to the State Implementation Plan for longer times for compliance determination.

IX.A.10.b. Compliance calculation procedures shall follow the guidance in "Procedure for Certifying Quantity of Volatile Organic Compounds Emitted by Paint, Ink, and Other Coatings," EPA-450/3-84/019. In addition, for add-on controls or other compliance alternatives, calculation procedures shall follow the guidance of Section IX.A.5.f.

IX.A.11. The requirements of Sections IX.A.1. through IX.A.10. apply to each category of surface coating as specified in Sections IX.B. through IX.M. The requirements of IX.A.7. through IX.A.10. apply to the category of IX.N.

IX.A.12. The Division shall approve utilization of alternative compliance methods to the following sources pursuant to this Section IX.

IX.A.12.a. Lexmark International, Inc. shall be allowed to utilize the alternative compliance method of crossline averaging for processes and operations within the Manufactured Metal Parts and Metal products (Subgroup L) and within the Plastic Film Coating Operations (Subgroup J). The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met, and utilization of the alternative compliance method shall be subject to the following generic conditions, which shall be written and specifically described as enforceable permit terms and conditions in its permits:

IX.A.12.a.(i) The alternative compliance method shall result in an actual reduction that is equivalent to the actual reduction that would otherwise be achieved on a line-by-line basis pursuant to this Regulation Number 7.

IX.A.12.a.(ii) Credit shall not be received for downtime; however, credit is allowed for emission reductions from enforceable production limits.

IX.A.12.a.(iii) Cross line averaging shall be used only across lines of the same control technique guidance group. Lexmark shall use cross line averaging between Metal Parts and Metal Products lines or between Plastic Film Coating lines. Lexmark shall not use cross line averaging where the emissions from Plastic film coating lines are averaged with Metal Parts and Metal Products lines.

IX.A.12.a.(iv) The emission trading policy set forth in Regulation Number 3, Part A, Section V., shall be met on a daily weighted average.

IX.A.12.a.(v) Sources subject to Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) shall not use cross line averaging.

IX.A.12.a.(vi) To determine reduction over baseline, VOC emissions shall be expressed according to Section IX. A. 5. f., as lbs/gallons solids.

IX.A.12.a.(vii) Monthly records shall be kept at the source to verify ongoing compliance with these conditions. The recordkeeping format shall be approved by the Division.

IX.A.12.a.(viii) An annual report demonstrating ongoing compliance with this regulation and all permit terms shall be filed with the Division. The report format shall be approved by the Division and specifically described in the permit.

IX.A.12.a.(ix) The Division shall issue a permit with federally enforceable terms and conditions to Lexmark limiting Lexmark's alternative compliance method emissions to those allowable under Section IX.L. and Section IX.J.

IX.A.12.a.(x) Commercial and Product quality control laboratory equipment are exempt from APEN filing and construction permit requirements under Regulation Number 3, Part A, Section II.D.1.(i), and Regulation Number 3, Part B, Section II.D.1.a.; and from construction permit requirements under Regulation Number 3, Part B, Section II.D.1.(i). Qualifying sources shall be exempt from Regulation Number 7, Section IX. A.6.

IX.A.12.a.(xi) Nothing in the alternative compliance method is intended to relax any emissions limitation of this Regulation Number 7.

IX.B. Automobile and Light-Duty Truck Assembly Plants

IX.B.1. Definitions

IX.B.1.a. “Application Area” means the area where the surface coating is applied by spraying, dipping or flow coating.

IX.B.1.b. "Automobile" means a passenger motor-vehicle or a derivative of same, capable of seating twelve (12) or fewer passengers, and having at least two driven wheels.

IX.B.1.c. "Automobile Assembly Facility" means a facility where parts (including assembled or partially assembled components) of automobiles are received, and finished automobiles are produced, partially or wholly by an assembly line.

IX.B.1.d. "Light-Duty Truck" means any motor vehicle rated at 8,500 pounds (3,855 kilograms) gross vehicle weight or less, and having at least two driven wheels, which is designed primarily for purposes of transportation of property or is a derivative of such vehicles. It includes, but is not limited to, pickup trucks, vans, and window vans rated at 8,500 pounds gross vehicular weight or less.

IX.B.1.e. "Light-Duty Truck Assembly Facility" means a facility where parts (including assembled or partially assembled components) of light-duty trucks are received, and finished light-duty trucks are produced, partially or wholly by an assembly line.

IX.B.2. Applicability

This section applies to all assembly and subassembly lines in an automobile or light-duty truck assembly facility, including those for frames, small parts, wheels, and main body parts. This section applies only to the manufacture of new vehicles.

IX.B.3. Emission Limitations

	Kg/lc	**Lb/gc**
Prime application, flashoff area, and oven	0.23	1.9
Topcoat application area, flashoff area, and oven	0.34	2.8
Final repair application, flashoff area and oven	0.58	4.8

IX.B.4. Coatings other than primer, surfacer (guidecoat), topcoat and final repair shall be considered under the miscellaneous metal parts Section IX.L.

IX.B.5. For topcoat application, if a complying coating is not used to meet the emission limit of Section IX.B.3, then:

IX.B.5.a. the alternate method shall meet an emission limit of 15.1 lb VOC/gal. solids deposited on the coated part; and

IX.B.5.b. compliance shall be determined on a daily weighted average basis.

IX.B.6. Topcoat operation shall include all spray booths, flash-off areas and ovens in which topcoat is applied, dried and cured, except for final offline repair.

IX.C. Can Coating Operations

IX.C.1. Definitions

IX.C.1.a. "Can Coatings" means any coatings containing organic materials and applied -- or intended for application -- by spray, roller, or other means onto the inside and/or outside surfaces of formed cans and components of cans.

IX.C.1.b. "End Sealing Compound" means a substance which is coated onto can ends and which functions as a seal when the end is assembled onto the can.

IX.C.1.c. "Exterior Base Coat" means a coating applied to the exterior of a can to provide protection to the metal and/or to provide background for any lithographic or printing operation.

IX.C.1.d. "Interior Base Coat" means the initial coating applied to the interior surface of a can by roller coater or spray.

IX.C.1.e. "Interior Body Spray" means a coating sprayed onto the interior surface of the can body to provide a protective film between the can and its contents.

IX.C.1.f. "Overvarnish" means a coating applied directly over ink to reduce the coefficient of friction, provide gloss, protect against abrasion, enhance product quality, and protect against corrosion.

IX.C.1.g. "Three-Piece Can Side Seam Spray" means a coating sprayed onto the interior and/or exterior of a can body seam on a three-piece can to protect the exposed metal.

IX.C.1.h. "Two-Piece Can Exterior End Coat" means a coating applied to the exterior of the bottom end of a two-piece can.

IX.C.2. Applicability

This section applies to coating applicator(s), and oven(s) of sheet can or end coating lines involved in sheet basecoat (exterior and interior) and over varnish, two-and three-piece can interior body spray, two-piece can exterior end (spray or roll coat), three-piece can side-seam spray, and end sealing compound operations.

IX.C.3. Emission Limitations

Can Coating	**Kg/lc**	**Lb/gc**
Sheet base coat (exterior and interior) and overvarnish two-piece can exterior (base coat and overvarnish)	0.34	2.8
Two and three-piece can interior body spray, two-piece can exterior end (spray or roll coat)	0.51	4.2
Three-piece can side-seam spray	0.66	5.5
End sealing compound	0.44	3.7
Any additional coats	0.51	4.2

IX.D. Coil Coating Operations

IX.D.1. Definitions

IX.D.1.a. "Coil Coating" means any surface coating applied by spray, roller, or other means onto one or both surfaces of flat metal sheets or strips that come in rolls or coils.

IX.D.1.b. "Quench Area" means a chamber where the hot metal exiting the oven is cooled by either a spray of water or a blast of air followed by water cooling.

IX.D.2. Applicability

This section applies to the coating applicator(s), oven(s), and quench area(s) of coil coating operations involved in primer, intermediate, top-coat or single-coat operations.

IX.D.3. Emission Limitations:

Coil Coating	**Kg/lc**	**Lb/gc**
Any coat (primer, intermediate coat, topcoat, single coat)	0.31	2.6

IX.E. Fabric Coating Operations

IX.E.1. Definitions

IX.E.1.a. "Fabric Coating" means the process of coating or impregnating the full, usable surface of a fabric web or sheet to impart properties that are not initially present such as strength, stability, water or acid repellency, or appearance. "Fabric Coating" excludes those processes normally included under fabric finishing (e.g. dyeing, treating for stain and wrinkle resistance, etc.).

IX.E.2. Applicability

This section applies to fabric coating lines which includes, but is not limited to, coaters and drying ovens.

IX.E.3. Emission Limitations

	Kg/lc	**Lb/gc**
Fabric Coating Line	0.35	2.9

IX.F. Large Appliance Coating Operations

IX.F.1. Definition

IX.F.1.a. "Large Appliances" includes doors, cases, lids, panels, interior support parts, and any other large (greater than one square decimeter (15.5 square inches)) coated surfaces of residential and commercial washers, dryers, ovens, ranges, refrigerators, freezers, water heaters, dishwashers, trash compactors, air conditioners, and all other products under SIC Code 363 according to the "Standard Industrial Classification Manual", Executive Office of the President, Office of Management and Budget, designated by convention of the industry as large appliances.

IX.F.2. Applicability

This section applies to all large appliance coating lines.

IX.F.3. Emission Limitations

	Kg/lc	**Lb/gc**
Large Appliance Coating Line; prime, single or topcoat application area, flashoff area, and oven	0.34	2.8

IX.G. Magnet Wire Coating Operations

IX.G.1. Definition

IX.G.1.a. "Magnet Wire Coating" means those operations which apply a coating of electrically insulating varnish or enamel (or similar substance) to wire which is known as "magnet wire." Magnet wire is usually copper or aluminum, and is used for electric motors, generators, transformers, magnets, and related products.

IX.G.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of magnet wire coating operations.

IX.G.3. Emission Limitations

	Kg/lc	**Lb/gc**
Magnetic wire coating operation	0.20	1.7

IX.H. Metal Furniture Coating Operations

IX.H.1. Definitions

IX.H.1.a. "Metal Furniture" means furnishings commonly considered furniture, for domestic, business, and/or institutional use, which have one or more essential, major components made of metal. "Metal furniture" includes, but is not limited to, tables, chairs, wastebaskets, beds, desks, lockers, shelving, cabinets, room dividers, clothing racks, chests of drawers, and sofas.

IX.H.1.b. "Metal Furniture Coating" means applying a "surface coating" to "metal furniture" as defined. It excludes coating of non-metal components.

IX.H.2. Applicability

This section applies to all metal furniture coating lines.

IX.H.3. Emission Limitations

	Kg/lc	**Lb/gc**
Metal Furniture Coating Line: All coats (including prime, single, and topcoat)	0.36	3.0

IX.I. Paper Coating Operations

IX.I.1. Definition

"Paper Coating" means impregnating or applying a uniform layer of "surface coating" to paper. It includes, but is not limited to, the production of: coated, glazed, decorated, and varnished paper; carbon and pressure-sensitive copy papers; paper adhesive-labels and tapes; blue-print; photographic and copier paper. It also includes coating of metal foil such as gift wrap and packaging. Paper coating does not include impregnation using a batch dipping process.

IX.I.2. Applicability

This section applies to paper coating lines, which includes, but is not limited to, coaters and drying ovens.

IX.I.3. Emission Limitations

	Kg/lc	**Lb/gc**
Paper Coating Line	0.35	2.9

IX.J. Plastic-Film Coating Operations

IX.J.1. Definition

IX.J.1.a. "Plastic-Film Coating" means applying a uniform layer of "surface coating" to a flexible web or sheet of thin plastic substance, excluding all rubbers and vinyl's* (polyvinyl chloride) except for the following two categories of vinyl products: (1) vinyl tapes and (2) vinyl's coated with an adhesive or pressure-sensitive coating. It includes, but is not limited to: plastic typewriter ribbons, photographic film, adhesive tapes, and magnetic recording tapes. (*see Section IX.K.)

IX.J.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of plastic-film coating lines.

IX.J.3. Emission Limitations

	Kg/lc	**Lb/gc**
Plastic-Film Coating Line	0.35	2.9

IX.K. Vinyl Coating Operations

IX.K.1. Definition

"Vinyl Coating" means applying a uniform layer, decorative or protective topcoat to a vinyl (polyvinyl chloride) coated fabric or vinyl sheet. It includes printing of same. Excluded are*: (1) the coating of same with adhesive or pressure-sensitive coatings and (2) vinyl tapes. (*see Section IX.J.)

IX.K.2. Application

This section applies to vinyl coating lines which includes, but is not limited to, coaters and drying ovens.

IX.K.3. Emission Limitations

	Kg/lc	**Lb/gc**
Vinyl Coating Line	0.45	3.8

IX.L. Manufactured Metal Parts and Metal Products

IX.L.1. General Provisions

IX.L.1.a. Applicability

This section applies to the application area(s), flashoff area(s), oven(s), and drying areas including (but not limited to) air and forced air drier(s) used in the surface coating of the metal parts and products listed below. This section applies to prime coat, top coat, and single coat operations. This section is applicable to surface coating of manufactured metal parts and metal products which include:

IX.L.1.a.(i) Large farm machinery (harvesting, fertilizing, and planting machines, tractors, combines, etc.);

IX.L.1.a.(ii) Small-farm, lawn and garden machinery (lawn and garden tractors, lawn mowers, rototillers, etc.);

IX.L.1.a.(iii) Small appliances (fans, mixers, blenders, crock pots, dehumidifiers, vacuum cleaners, etc.);

IX.L.1.a.(iv) Commercial machinery (office equipment, computers and auxiliary equipment, typewriters, calculators, vending machines, etc.);

IX.L.1.a.(v) Industrial machinery (pumps, compressors, conveyor components, fans, blowers, transformers, etc.);

IX.L.1.a.(vi) Fabricated metal products (metal covered doors, frames, etc.);

IX.L.1.a.(vii) Furniture hardware made of metal for use with non-metal furniture; and

IX.L.1.a.(viii) Any other industrial category which coats metal parts or products under the standard industrial classification code of major group 33 (primary metal industries), major group 34 (fabricated metal products), major group 35 (non-electric machinery), major group 36 (electrical machinery), major group 37 (transportation equipment), major group 38 (miscellaneous instruments), and major group 39 (miscellaneous manufacturing industries), according to the “Standard Industrial Classification Manual” Executive Office of the President, Office of Management and Budget.

IX.L.1.b. Exemptions

IX.L.1.b.(i) This Section IX.L. is not applicable to the surface coating of the following metal parts and products inasmuch as these are previously covered in Sections IX.B., C., D., F., G., and H., respectively:

IX.L.1.b.(i)(A) Automobiles and light-duty trucks

IX.L.1.b.(i)(B) Metal cans

IX.L.1.b.(i)(C) Flat metal sheets and strips in the form of rolls or coils

IX.L.1.b.(i)(D) Large appliances

IX.L.1.b.(i)(E) Magnet wire for use in electrical machinery

IX.L.1.b.(i)(F) Metal furniture

IX.L.1.b.(ii) This Section IX.L. is not applicable to the following special purpose coatings:

IX.L.1.b.(ii)(A) Division-approved exemptions for high performance coatings on a case-by-case basis.

IX.L.1.b.(ii)(B) Full exterior repainting of automobiles and light-duty trucks if fewer than 18 vehicles are painted per day.

IX.L.1.c. Definitions

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

IX.L.1.c.(i) "Air Dried Coating" means coatings which are dried by the use of air or forced warm air at temperatures up to 90°C (194°F);

IX.L.1.c.(ii) "Clear Coat" means a coating, which lacks color and opacity or a coating which is transparent;

IX.L.1.c.(iii) "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, flashoff areas, air dryers and ovens;

IX.L.1.c.(iv) "Extreme Environmental Conditions" means exposure to any of the following: temperatures consistently above 95°C, detergents, abrasive and scouring agents, solvents, and corrosive environments;

IX.L.1.c.(v) "Extreme Performance Coatings" means coatings designed for extreme environmental conditions.

IX.L.2. Provisions for Specific Processes

IX.L.2.a. No owner or operator of a facility or operation engaging in the surface coating of manufactured metal parts or metal products may operate a coating application system subject to this regulation that emits VOC in excess of:

IX.L.2.a.(i) Clear coatings: 0.52 kg/lc(4.3 lb/gc)

IX.L.2.a.(ii) Extreme Performance Coatings: 0.42 kg/lc (3.5 lb/gc)

IX.L.2.a.(iii) Air-Dried Coatings: 0.42 kg/lc (3.5 lb/gc)

IX.L.2.a.(iv) Other coatings and systems: 0.36 kg/lc (3.0 lb/gc) delivered to a coating applicator for all other coatings and coating application systems.

IX.L.2.b. If more than one emission limitation in Section IX.L.2.a. applies to a specific coating, then the least stringent emission limitation shall be applied.

IX.L.2.c . Pioneer Metal Finishing, Inc., a surface coating operation, is authorized pursuant to Regulation Number 3, Part A, Section V. and Regulation Number 7, Section II.D.1.a. to use up to twenty (20) tons of certified emission reduction credits of volatile organic compounds (VOC) as an alternative compliance method to satisfy the surface coating emission limitations of Regulation Number 7 in accordance with and upon demonstration of the conditions set forth below::

IX.L.2.c.(i) Certified emission reduction credits for VOCs (methanol) to be used in this transaction were formerly owned by the Coors Brewing Company, registered and issued in Emissions Reduction Credit Permit 91AR120R on July 25, 1994;

IX.L.2.c.(ii) Those emission reduction credits were originally obtained by Coors from Verticel, a company that produced honeycomb packaging material and was located within five miles of the PMF facility;

IX.L.2.c.(iii) The use of these VOC emission reduction credits identified above shall be used to satisfy VOC limitations of certain specified surface coatings in excess of Control Technique Guidance as specified in Regulation Number 7, Section IX.L.2.a. and Section IX.A.6.b., and applicable to the Pioneer Metal finishing operations;;

IX.L.2.c.(iv) Such emission reduction credits identified above will be used by PMF to achieve compliance with Regulation Number 7 to compensate for ozone precursor emission of VOCs from non-compliant coatings which meet the emission trading requirements of Regulation Number 3, Part A, Section V. In order to satisfy the photochemical reactivity equivalency requirement of VOC trades, the methanol VOC ERCs will be reduced on a ratio of 1.1:1 for VOCs of toluene, ethylbenzene, xylene and ketones emitted from non-compliant coatings. All other VOCs involved in this transaction are considered to be of the same degree of photochemical reactivity;

IX.L.2.c.(v) The requirement in Regulation Number 3, Part A, Section V.F.2. shall not apply to this transaction;

IX.L.2.c.(vi) This transaction is only valid within the Denver/Boulder nonattainment area as described at 40 CFR 81, Subchapter C - Air Programs, Subpart C, Section 107 - Attainment Status Designations, Section 81.306;

IX.L.2.c.(vii) This transaction shall be calculated upon a pound for pound basis and averaged over a maximum 24-hour period.

IX.L.2.c.(viii) This transaction shall be effective upon approval by the U.S. Environmental Protection Agency as a revision to the Colorado State Implementation Plan and after issuance of a State Construction Permit incorporating, but not limited to, the conditions and requirements of the Section;

IX.L.2.c.(ix) This transaction may not be used to satisfy any current or future requirements of NSPS, BACT, LAER, or MACT requirements of HAPs which may apply to PMF, except that this transaction may be used to satisfy control technique guidance or RACT requirements contained in Regulation Number 7 which are applicable to PMF;

IX.L.2.c.(x) This transaction shall not interfere with any applicable requirement concerning attainment and reasonable further progress in the Colorado State Implementation Plan or any other applicable requirements of the Clean Air Act;

IX.L.2.c.(xi) This transaction shall be registered and enforced through a State Construction Permit issued to Pioneer Metal Finishing, Inc. containing, but not limited to the conditions and limitations set forth in this Section;

IX.L.2.c.(xii) Such state Construction Permit issued to Pioneer Metal Finishing, Inc. shall specify, among other, things the necessary monitory, recordkeeping and reporting requirements to insure that the emission reduction credits are applied in accordance with the conditions and requirements of this Section;

IX.L.2.c.(xiii) The state Construction Permit shall allow a daily maximum limitation of 160 lbs. of VOC emissions from non-compliant surface coatings and an annual limitation of 40,000 lbs. of non-compliant VOC emissions. The annual limitation shall be calculated on a 12-month rolling total calculated on the first day of each month using the previous 12 months.

IX.L.2.c.(xiv) The state Construction Permit shall limit the VOC-HAP emissions to less than ten (10) per year of any one HAP or twenty-five (25) tons per year of any combination of HAP emissions; and

IX.L.2.c.(xv) PMF will maintain records of daily and monthly totals of non-compliant surface coatings used in its operation and report such usages on an annual basis to the Division or as otherwise requested.

IX.M. Flat Wood Paneling Coating.

IX.M.1. Definitions

IX.M.1.a. “Class II Hardboard Paneling Finish” means finishes which meet the specifications of Voluntary Product Standard PS-59-73 as approved by the American National Standards Institute.

IX.M.1.b. “Coating Application System” means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, conveyers, flashoff areas, air dryers and ovens.

IX.M.1.c. “Hardboard” is a panel manufactured primarily from inter-felted ligno-cellulosic fibers which are consolidated under heat and pressure in a hot press.

IX.M.1.d. “Hardboard Plywood” is plywood whose surface layer is a veneer of hardwood.

IX.M.1.e. "Natural Finish Hardwood Plywood Panels" means panels whose original grain pattern is enhanced by essentially transparent finishes frequently supplemented by fillers and toners.

IX.M.1.f. "Printed Interior Panels" means panels whose grain or natural surface is obscured by fillers and basecoats upon which a simulated grain or decorative pattern is printed.

IX.M.1.g. "Thin Particleboard" is a manufactured board 1/4 inch or less in thickness made of individual wood particles which have been coated with a binder and formed into flat sheets by pressure.

IX.M.1.h. "Tileboard" means paneling that has a colored waterproof surface coating.

IX.M.2. Applicability

This section applies to all flat wood manufacturing and surface finishing facilities that manufacture printed interior panels made of hardwood plywood and thin particle board; natural finish hardwood plywood panels, or hardboard paneling with Class II finishes. This section does not apply to the manufacture of exterior siding, tileboard, or particleboard used as a furniture component.

IX.M.3. Emission Limitations

IX.M.3.a. 2.9 kg per 100 square meters of coated finished product (6.0 lb/1,000 sq. ft.) from printed interior panels, regardless of the number of coats applied;

IX.M.3.b. 5.8 kg per 100 square meters of coated finished product (12.0 lb/1,000 sq. ft.) from natural finish hardwood plywood panels, regardless of the number of coats applied; and

IX.M.3.c. 4.8 kg per 100 square meters of coated finished product (10.0 lb/1,000 sq. ft.) from Class II finishes on hardboard panels, regardless of the number of coats applied.

IX.N. Manufacture of Pneumatic Rubber Tires

IX.N.1. Definitions

IX.N.1.a. "Bead Dipping" means the dipping of an assembled tire bead into a solvent-based cement.

IX.N.1.b. "Green Tires" means assembled tires before holding and curing have occurred.

IX.N.1.c. "Green Tire Spraying" means the spraying of green tires, both inside and outside, with release compounds which help remove air from the tire during molding and prevent the tire from sticking to the mold after curing.

IX.N.1.d. "Pneumatic Rubber Tire Manufacture" means the production of pneumatic rubber, passenger type tires on a mass production basis.

IX.N.1.e. "Passenger Type Tire" means agricultural, airplane, industrial, mobile home, light and medium duty truck, and passenger vehicle tires with a bead diameter up to 20.0 inches and cross section dimension up to 12.8 inches.

IX.N.1.f. "Tread End Cementing" means the application of a solvent-based cement to the tire tread ends.

IX.N.1.g. "Undertread Cementing" means the application of a solvent-based cement to the underside of a tire tread.

IX.N.1.h. "Water Based Sprays" means release compounds, sprayed on the inside and outside of green tires, in which solids, water, and emulsifiers have been substituted for organic solvents.

IX.N.2. Applicability

This section applies to VOC emissions from the following operations in all pneumatic rubber tire facilities: undertread cementing, tread end cementing, bead dipping, and green tire spraying.

The provisions of this section do not apply to the production of specialty tires for antique or other vehicles when produced on an irregular basis or with short production runs. This exemption applies only to tires produced on equipment separate from normal production lines for passenger type tires.

IX.N.3. Provisions for Specific Processes

IX.N.3.a. The owner or operator of an undertread cementing, tread end cementing, or bead dipping operation subject to this regulation shall:

IX.N.3.a.(i) Install and operate a capture system, designed to achieve maximum reasonable capture, up to 85 percent by weight of VOC emitted, from all undertread cementing, tread end cementing and bead dipping operations. Maximum reasonable capture shall be consistent with the following documents:

IX.N.3.a.(i)(A) Industrial Ventilation, A Manual of Recommended Practices, 17th Edition, American Federation of Industrial Hygienists, 1982.

IX.N.3.a.(i)(B) Recommended Industrial Ventilation Guidelines, U.S. Department of Health, Education and Welfare, National Institute of Occupational Safety and Health, January 1976.

IX.N.3.a.(ii) Install and operate a control device that meets the requirements of one of the following:

IX.N.3.a.(ii)(A) A carbon adsorption system designed and operated in a manner such that there is at least a 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

IX.N.3.a.(ii)(B) An incineration system that oxidizes at least 90.0 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) which enter the incinerator to carbon dioxide and water.

IX.N.4. The owner or operator of a green tire spraying operation subject to this regulation must implement one of the following means of reducing volatile organic compound emissions:

IX.N.4.a. Substitute water-based sprays for the normal solvent-based mold release compound; or,

IX.N.4.a.(i) Install a capture system designed and operated in a manner that will capture and transfer at least 90.0 percent of the VOC emitted by the green tire spraying operation to a control device; and,

IX.N.4.a.(ii) In addition to Section IX.N.4.a.(i), install and operate a control device that meets the requirements of one of the following:

IX.N.4.a.(ii)(A) a carbon adsorption system designed and operated in a manner such that there is at least 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

IX.N.4.a.(ii)(B) an incineration system that oxidizes at least 90 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) to carbon dioxide and water.

IX.N.5. Testing of capture system efficiency shall meet the requirements of Section IX.A.5.e.

IX.N.6. Control devices shall meet the applicable requirements, including recordkeeping, of Sections IX.A.3.a., b., c., and e., and IX.A.8.a. and b.

IX.N.7. The applicable EPA reference methods I through 4, and 25, of 40 CFR Part 60, shall be used to determine the efficiency of control devices.

X. Use of Cleaning Solvents

X.A. General Provisions

X.A.1. Applicability

The provisions of this section apply to cold cleaners, non-conveyorized vapor degreasers, conveyorized degreasers, and industrial cleaning solvent operations. Open top vapor degreasers are a subset of non-conveyorized vapor degreasers. The owner or operator of a unit subject to this section shall ensure that no such unit is used unless the requirements of this section are satisfied. Section X.E. requirements are effective on January 1, 2017.

X.A.2. Definitions

X.A.2.a. “Cold-Cleaner” means a container of non-aqueous liquid solvent held below its boiling point, which is designed, used, or intended for cleaning solid objects in a batch-loaded process. A “cold-cleaner” may have provisions for heating the solvent. It does not include vapor degreasers or continuously loaded conveyorized degreasers.

X.A.2.b. “Composite Partial Vapor Pressure” means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the "i"th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the "i"th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

X.A.2.c. "Conveyorized Degreaser" means an apparatus that performs degreasing or other cleaning functions through the use of non-aqueous liquid solvent and/or solvent vapors within a container, and which has a conveyor mechanism allowing continuous loading of items conveyed into and out of the solvent.

X.A.2.d. "Freeboard" in a vapor degreaser means the vertical distance from the top of the vapor zone (as established by normal operations within the specifications of the degreaser manufacturer) to the top of the degreaser.

For cold-cleaners "freeboard" means the vertical distance from the surface of the solvent liquid to the top of the degreaser.

If all sides are not even, the vertical distance to the top of the lowest side shall be used to make the determination of freeboard.

X.A.2.e. "Freeboard Ratio" means the ratio of the freeboard to the width of the solvent surface.

X.A.2.f. "Industrial Cleaning Solvent" means a VOC-containing liquid used to perform industrial cleaning solvent operations.

X.A.2.g. "Industrial Cleaning Solvent Operation" means the use of an industrial cleaning solvent for cleaning industrial operations such as spray gun cleaning, spray booth cleaning, large manufactured parts cleaning, equipment cleaning, floor cleaning, line cleaning, parts cleaning, tank cleaning, and small manufactured parts cleaning. Residential and janitorial cleaning are not considered industrial cleaning solvent operations.

X.A.2.h. "Non-Conveyorized Vapor Degreaser" means an apparatus, which uses non-aqueous solvent vapors within some type of container to degrease or otherwise clean solid objects in a batch-loaded process. It excludes continuously loaded conveyorized degreasers.

X.A.2.i. "Residential and Janitorial Cleaning" means the cleaning of a building or building components including, but not limited to, floors, ceilings, wall, windows, doors, stairs, bathrooms, furnishings, and exterior surfaces of office equipment, excluding the cleaning of work areas where manufacturing or repair activity is performed.

X.A.2.j. "Solvent Metal Cleaning" means the process of cleaning soils from metal surfaces by cold cleaning, conveyorized degreasing, or non-conveyorized vapor degreasing.

X.A.3. Transfer of waste solvent and used solvent

In any disposal or transfer of waste or used solvent, at least 80 percent by weight of the solvent/waste liquid shall be retained (i.e., no more than 20 percent of the liquid solvent/solute mixture shall evaporate or otherwise be lost during transfers).

X.A.4. Storage of waste solvent and used solvent

Waste or used solvent shall be stored in closed containers unless otherwise required by law.

X.A.5. Any control device shall meet the applicable requirements of Sections IX.A.3.a., b., c., e., and IX.A.8.a. and b.

X.B. Control of Solvent Cold-Cleaners

X.B.1. Control Equipment

X.B.1.a. Covers

X.B.1.a.(i) All cold-cleaners shall have a properly fitting cover.

X.B.1.a.(ii) Covers shall be designed to be easily operable with one hand under any of the following conditions:

X.B.1.a.(ii)(A) Solvent true vapor pressure is greater than 15 torr (0.3 psia) at 38°C (100°F).

X.B.1.a.(ii)(B) The solvent is agitated by an agitating mechanism.

X.B.1.a.(ii)(C) The solvent is heated.

X.B.1.b. Drainage Facility

X.B.1.b.(i) All cold-cleaners shall have a drainage facility that captures the drained liquid solvent from the cleaned parts.

X.B.1.b.(ii) For cold-cleaners using solvent which has a vapor pressure greater than 32 torr (0.62 psia) measured at 38°C (100°F) either:

X.B.1.b.(ii)(A) There shall be an internal drainage facility within the confines of the cold-cleaner, so that parts are enclosed under the (closed) cover to drain after cleaning, or if such a facility will not fit within;

X.B.1.b.(ii)(B) An enclosed, external drainage facility that captures the drained solvent liquid from the cleaned parts.

X.B.1.c. A permanent, clearly visible sign shall be mounted on or next to the cold-cleaner. The sign shall list the operating requirements.

X.B.1.d. Solvent spray apparatus shall not have a splashing, fine atomizing, or shower type action but rather should produce a solid, cohesive stream. Solvent spray shall be used at a pressure that does not cause excessive splashing.

For solvents with a true vapor pressure above 32 torr (0.62 psia) at 38°C (100°F), or, for solvents heated above 50°C (120°F), one of the following techniques shall be used:

X.B.1.d.(i) A freeboard ratio greater than or equal to 0.7.

X.B.1.d.(ii) A water or a non-volatile liquid cover. The cover liquid shall not be soluble in the solvent and shall not be denser than the solvent and the depth of the cover liquid shall be sufficient to prevent the escape of solvent vapors.

X.B.2. Operating requirements

X.B.2.a. The cold-cleaner cover shall be closed whenever parts are not being handled within the cleaner confines.

X.B.2.b. Cleaned parts shall be drained for at least 15 seconds and/or until dripping ceases. Any pools of solvent shall be tipped out on the clean part back into the tank.

X.C. Control of Non-Conveyorized Vapor Degreasers

X.C.1. Control Equipment

X.C.1.a. The non-conveyorized vapor degreaser shall have a cover which shall be designed and operated so that it can be easily opened and closed through the use of mechanical assists such as spring loading, counterweights, etc.; opening and closing the cover shall not disturb the vapor zone.

X.C.1.b. Safety Switches

The following two types of switches shall be installed on vapor degreasers:

X.C.1.b.(i) Condenser flow switch and thermostat - (shuts off sump heat if the condenser coolant is either not circulating or is too warm); and

X.C.1.b.(ii) Spray safety switch - (shuts off spray pump if the vapor level drops more than four (4) inches).

X.C.1.c. Control Device

X.C.1.c.(i) For non-conveyorized vapor degreasers with an open area (with the cover open) of one square meter (10.8 ft_2) or less, either the freeboard ratio shall be greater than or equal to 0.75, or one of the control devices in X.C.1.c.(ii) shall be used.

X.C.1.c.(ii) For non-conveyorized vapor degreasers with an open area (with the cover open) greater than one (1) square meter, (10.8 ft_2), at least one of the following control systems shall be used:

X.C.1.c.(ii)(A) Both a powered cover and a freeboard ratio greater than or equal to 0.75.

X.C.1.c.(ii)(B) A refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix C.

X.C.1.c.(ii)(C) An enclosed design: A system where the cover(s) or door(s) opens only when a dry part is entering or exiting the degreaser.

X.C.1.c.(ii)(D) A carbon adsorption system with ventilation greater than or equal to 15 cubic meters each minute per square meter (50 cfm/ft_2) of air/vapor area (when the cover(s) is [are] open), exhausting less than 25 parts per million (by volume) of solvent averaged over one complete adsorption cycle.

X.C.1.d. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

X.C.2. Operating Requirements

X.C.2.a. Keep cover closed at all times except when processing work loads into or out of the degreaser.

X.C.2.b. The following operations shall be performed to minimize solvent carry-out:

X.C.2.b.(i) Rack parts to allow full drainage.

X.C.2.b.(ii) Move parts as slowly as is practicable in and out of the degreaser. A maximum of one foot every five seconds by hand or a maximum of 5.5 cm/sec. (10.8ft/min) for a mechanically operated system.

X.C.2.b.(iii) Allow the workload to clean in the vapor zone at least 30 seconds or until condensation ceases.

X.C.2.b.(iv) Tip out any pools of solvent that remain on the cleaned parts before removal from the vapor zone.

X.C.2.b.(v) Allow parts to dry within the degreaser at least 15 seconds and/or until visually dry.

X.C.2.c. Solvents shall not be used to clean porous or absorbent materials; for example, cloth, leather, wood, rope, etc.

X.C.2.d. Workloads shall not occupy more than half of the degreaser's open top area.

X.C.2.e. Spraying shall not be done above the vapor level.

X.C.2.f. Solvent leaks shall be repaired immediately, or the degreaser shall be shut down.

X.C.2.g. Exhaust ventilation shall not exceed twenty (20) cubic meters per minute per square meter (65.6 cfm per sq. ft.) of degreaser open area, unless greater exhaust rates are necessary to meet Occupational and Safety Health Act requirements. Ventilation fans shall not be used near the degreaser opening, unless necessary to meet Occupational and Safety Health Act requirements.

X.C.2.h. The water separator shall function so that no visible water is present in the solvent exiting the separator.

X.D. Control of Conveyorized Degreasers

X.D.1. Control Equipment

X.D.1.a. Control Device

For all conveyorized degreasers with a solvent surface area greater than two (2) square meters (21.5 square feet), the degreasing shall be controlled by at least one of the following:

X.D.1.a.(i) Carbon adsorption system, with ventilation greater or equal to 15 cubic meters per minute per square meter (49.2 cfm/ft2) of air/vapor interface for vapor degreasers (of air/liquid interface for non-vapor types) when down-time covers are open, and exhausting less than 25 parts per million of solvent (by volume) averaged over a complete adsorption cycle.

X.D.1.a.(ii) For vapor degreasers only: a refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix D.

X.D.1.b. Prevention of Carry-out

A drying tunnel, tumbling basket(s), or other demonstrably effective method(s) shall be employed to prevent cleaned parts from carrying out solvent liquid or vapor.

X.D.1.c. Safety Switches

X.D.1.c.(i) The following two (2) switch-circuits (or equivalent) shall be installed.

X.D.1.c.(i)(A) A spray safety switch shall shut off the spray pump and/or the conveyor if the vapor level drops more than four (4) inches.

X.D.1.c.(i)(B) A vapor level control thermostat shall shut off sump heat when the vapor level rises too high.

X.D.1.c.(ii) All conveyorized degreasers shall have a condenser thermostat and flow-detector switch (or equivalent) which shuts off sump heat if coolant is too warm or is not circulating.

X.D.1.d. Minimized Openings: Degreaser entrance and exit openings shall silhouette workloads so that the average clearance between parts (or parts-and the edge of the degreaser opening) is either:

X.D.1.d.(i) less than 10 centimeters (4 inches) or;

X.D.1.d.(ii) less than 10 percent of the width of the opening

X.D.1.e. Covers shall be provided to close off all the entrance(s) and exit(s) when the conveyor is not in use.

X.D.1.f. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

X.D.2. Operating Requirements

X.D.2.a. Exhaust ventilation shall not exceed 20 m^3/minute per square meter of degreaser opening (65.6 cf/m per square foot), unless necessary to meet OSHA requirements. Work place fans shall not be located near, nor directed at degreaser openings, unless necessary to meet OSHA requirements. Exhaust flow shall be measured by EPA reference methods 1 and 2 of 40 CFR Part 60.

X.D.2.b. Carry-out emissions shall be minimized by:

X.D.2.b.(i) Racking parts in such a manner to achieve best drainage.

X.D.2.b.(ii) Maintaining the vertical component of conveyor speed at less than 3.3 meters per minute (10.8 feet per minute).

X.D.2.c. Repair solvent leaks immediately, or shut down the degreaser.

X.D.2.d. The water separator shall function with an efficiency sufficient to prevent water from being visible in the solvent exiting the separator.

X.D.2.e. Down-time cover(s) shall be placed over entrances and exits of conveyorized degreasers immediately after the conveyor and exhaust are shut down. Covers shall be retained in position until immediately before start-up.

X.E. Control of Industrial Cleaning Solvent Operations

X.E.1. Control Requirements

The owner or operator of an industrial cleaning solvent operation with total combined uncontrolled actual VOC emissions equal to or greater than three (3) tons per calendar year (excluding VOC emissions from solvents used for cleaning operations that are exempt under Section X.E.4.) must:

X.E.1.a. Limit the VOC content of cleaning solvents to less than or equal to 0.42 lb of VOC/gal (50 grams VOC/liter); or

X.E.1.b. Limit the composite partial vapor pressure of the cleaning solvent to 8 millimeters of mercury (mmHg) at 20 degrees Celsius (68 degrees Fahrenheit); or

X.E.1.c. Reduce VOC emissions with an emission control system having a control efficiency of 90% or greater.

X.E.2. Work Practice Requirements

The owner or operator of an industrial cleaning solvent operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

X.E.2.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

X.E.2.b. Properly dispose of used solvent and shop towels; and

X.E.2.c. Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintaining cleaning equipment to be leak free.

X.E.3. Monitoring, Recordkeeping and Reporting Requirements

X.E.3.a. The owner or operator of an industrial cleaning solvent operation must keep the following records for two (2) years and make them available for inspection by the Division upon request:

X.E.3.a.(i) If applicable, records demonstrating that a listed exemption to this Section X.E. applies.

X.E.3.a.(ii) If applicable, monthly records such as safety data sheets or other analytical data from the industrial cleaning solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent cleaning operations to demonstrate compliance with the control requirements in Sections X.E.1.a. and X.E.1.b.

X.E.3.a.(iii) If applicable, monthly records sufficient to demonstrate compliance with the control requirement in Section X.E.1.c.

X.E.3.a.(iv) Records of calendar year VOC emission estimates demonstrating whether the industrial cleaning solvent operation meets or exceeds the applicability threshold in Section X.E.1.

X.E.3.b. Compliance with the control requirements in Section X.E.1. must be demonstrated using one of the following methods as applicable:

X.E.3.b.(i) Safety data sheets or other analytical data from the industrial cleaning solvent manufacturer to demonstrate compliance with Sections X.E.1.a. and X.E.1.b.;

X.E.3.b.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with Section X.E.1.c.; or

X.E.3.b.(iii) A performance test conducted during representative operations using one of the following methods, as applicable:

X.E.3.b.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) to determine VOC content;

X.E.3.b.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) to determine control efficiency of the emission control equipment.

X.E.4. Exemptions

X.E.4.a. Industrial cleaning solvent operations are not subject to Section X.E. if they are subject to one of the following:

X.E.4.a.(i) A work practice or emission control requirement in a federally enforceable New Source Performance Standard in 40 CFR Part 60, National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63, a Best Available Control Technology requirement of Regulation Number 3, Part B, a Lowest Achievable Emissions Rate requirement of Regulation Number 3, Part D; or

X.E.4.a.(ii) A work practice or emission control requirement in another federally enforceable section of Regulation 7 which establishes RACT.

X.E.4.b. The VOC control requirements in Section X.E.1. do not apply to:

X.E.4.b.(i) Cleaning of electrical and electronic components;

X.E.4.b.(ii) Cleaning of precision optics;

X.E.4.b.(iii) Cleaning of numismatic dies;

X.E.4.b.(iv) Stripping of cured inks, coatings, and adhesives;

X.E.4.b.(v) Cleaning of resin, coating, ink, and adhesive manufacturing, mixing, molding, and application equipment;

X.E.4.b.(vi) Cleaning of research and development laboratories;

X.E.4.b.(vii) Cleaning of medical device or pharmaceutical manufacturing equipment;

X.E.4.b.(viii) Performance testing to determine coating, adhesive, ink or ink performance;

X.E.4.b.(ix) Cleaning of equipment and materials used in testing for quality control or quality assurance purposes;

X.E.4.b.(x) Cleaning of digital printing operations; and

X.E.4.b.(xi) Cleaning of screen printing operations.

X.E.4.c. In lieu of compliance with Section X.E.1. and X.E.2., the owner or operator of an area source aerospace facility, as defined in 40 CFR Part 63, Section 63.742, may implement the solvent cleaning provisions of the National Emission Standards for Hazardous Air Pollutants for Aerospace Manufacturing and Rework facilities contained in 40 CFR Part 63, Section 63.744 along with the applicable definitions contained in 40 CFR Part 63, Section 63.742, except that:

X.E.4.c.(i) VOC-containing solvents which meet the definition of "non-HAP materials" in 40 CFR Part 63, Section 63.742 are not excluded from the housekeeping measures contained in 40 CFR Part 63, Section 63.744(a); and

X.E.4.c.(ii) The baseline reduction compliance option contained in 40 CFR Part 63, Section 63.744(b)(3) is not available for purposes of compliance with this VOC control rule.

XI. Use of Cutback Asphalt

XI.A. Definitions

XI.A.1. "Asphalt or Asphalt Cement" The dark-brown to black cementitious material (solid, semi-solid, or liquid in consistency) of which the main constituents are bitumen's which occur naturally or as a residue of petroleum refining.

XI.A.2. "Asphalt Concrete" A waterproof and durable paving material composed of dried aggregate, which is evenly coated with hot asphalt cement.

XI.A.3. "Cutback Asphalt or Cutback Asphalt Cement" Any asphalt which has been liquefied by blending with a VOC, such as a petroleum solvent diluents or, in the case of some slow cure asphalts (Road Oils), which has been produced directly from the distillation of petroleum.

XI.A.4. "Emulsified Asphalt" Asphalt emulsions produced by combining asphalt and water with emulsifying agent.

Emulsified Asphalt or any other coating or sealant, including but not limited to those produced from petroleum or coal, which contain more than five (5) percent of oil distillate as determined by ASTM Method D-244 is included in this definition.

XI.A.5. "Penetrating Prime Coat" An application of low-viscosity liquid asphalt to an absorbent surface in order to prepare it for overlaying with a layer or layers of asphalt cement or asphalt emulsion and mineral aggregate paving materials.

XI.B. Limitations

XI.B.1. Applicability

The provisions of this Section XI. apply to the use and storage of cutback asphalt for the paving and maintenance of all public roadways (including alleys), private roadways, parking lots, and driveways only within ozone nonattainment areas.

XI.B.2. Storage

Stockpiles of aggregate mixed with cutback asphalt are permitted October 1 through February 28 (29). Such storage is not permitted March 1 through September 30 except where it can be demonstrated to the Division that such storage is necessary.

XI.B.3. Use

Cutback asphalt may be used for any paving purpose October 1 through February 28 (29). No person shall use cutback asphalt or any coating included in the definition of cutback asphalt in Section IX.A.3. March 1 through September 30 except as provided:

XI.B.3.a. If used solely as a penetrating prime coat, or

XI.B.3.b. If the user can demonstrate to the Division that under the conditions of its intended use, there will be no emissions of volatile organic compounds to the ambient air.

XI.C. Recordkeeping

During the months of March through September, the person responsible for the use or storage of any cutback asphalt as permitted in Sections XI.B.3.a., XI.B.3.b., and Section XI.B.2. shall keep records of same, including type and amount of solvent(s) used.

XII. Volatile Organic Compound Emissions from Oil and Gas Operations

XII.A. Applicability

XII.A.1. Except as provided in Section XII.A.2. through XII.A.7.., this section applies to oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations:

XII.A.1.a. that collect, store, or handle condensate in the 8-hour Ozone Control Area (State Only: or any ozone nonattainment or attainment/maintenance area),

XII.A.1.b. that are located upstream of a natural gas plant,

XII.A.1.c. for which the owner or operator filed, or was required to file, an APEN pursuant to Regulation Number 3, Part A, and

XII.A.1.d. (State Only) that emit any amount of uncontrolled actual volatile organic compound emissions with the following exceptions.

XII.A.1.d.(i) (State Only) Volatile organic compounds emitted during the first 90 days from the date of first production for new and modified condensate storage tanks as defined in Section XII.B. must be equipped with a control device pursuant to Section XII.D., and comply with applicable monitoring, recordkeeping, and reporting requirements; and

XII.A.1.d.(ii) All dehydrators regardless of uncontrolled actual emissions are subject to Section XII.H.

XII.A.2. Oil refineries are not subject to Section XII.

XII.A.3. Natural gas-processing plants located in an ozone nonattainment or attainment maintenance area are subject to Section XII.G. and qualifying natural gas compressor stations located in an ozone nonattainment or attainment maintenance area are subject to Section XII.I.

XII.A.4. Glycol natural gas dehydrators located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas processing plant in an ozone nonattainment or attainment maintenance area are subject to Sections XII.B. and XII.H.

XII.A.5. Well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year, as determined in Section XII.L.2.c., and natural gas compressor stations that collect, store, or handle hydrocarbon liquids are subject to Sections XII.B. and XII.L.

XII.A.6. Centrifugal compressors, reciprocating compressors, and pneumatic pumps are subject to Sections XII.B., XII.C.1.c. through XII.C.1.e., XII.J., and XII.K.

XII.A.7. The requirements of Sections XII.B. through XII.I. do not apply to any owner or operator in any calendar year in which the APENs for all of the atmospheric condensate storage tanks associated with the affected operations owned or operated by such person reflect a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the 8-Hour Ozone Control Area. Such requirements do, however, apply to such owner or operator in any subsequent calendar year in which the APENs for atmospheric condensate storage tanks associated with such affected operations reflect a total of 30 tons per year or more of actual uncontrolled emissions of VOCs in the 8-Hour Ozone Control Area.

XII.B. Definitions Specific to Section XII.

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

XII.B.2. “Air Pollution Control Equipment”, as used in Section XII., 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 XII.D.2.b. that are approved by the Division..

XII.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 XII.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.

XII.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.

XII.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.

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

XII.B.7. “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.

XII.B.8. "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.

XII.B.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.

XII.B.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.

XII.B.11. "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.

XII.B.12. "Downtime" means the period of time when a well is producing and the air pollution control equipment is not in operation.

XII.B.13. "Existing" means any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.

XII.B.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.

XII.B.15. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

XII.B.16. "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, a physical change or change in operation includes but is not limited to drilling new wells and recompleting, refracturing or otherwise stimulating existing wells.

XII.B.17. "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.

XII.B.18. "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.

XII.B.19. "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.

XII.B.20. "New" means any atmospheric condensate storage tank that began operation on or after February 1, 2009.

XII.B.21. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

XII.B.22. "Stabilized" when used to refer to stored condensate, means that the condensate has reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses".

XII.B.23. (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.

XII.B.24. "System-Wide" when used to refer to emissions and emission reductions in Section XII.D., means collective emissions and emission reductions from all atmospheric condensate storage tanks under common ownership within the 8-hour Ozone Control Area or other specific Ozone Nonattainment or Attainment Maintenance Area for which uncontrolled actual volatile organic compound emissions are equal to or greater than two tons per year.

XII.B.25. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XII.C. General Provisions to Section XII.

XII.C.1. General Requirements for Air Pollution Control Equipment – Prevention of Leakage

XII.C.1.a. All air pollution control equipment used to demonstrate compliance with this Section XII. shall be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates required by this Section XII. 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.

XII.C.1.b. All condensate collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the maximum extent practicable.

XII.C.1.c. All air pollution control equipment used to demonstrate compliance with Sections XII.D., XII.J. and XII.K. must meet a control efficiency of at least 95%. Failure to properly install, operate, and maintain air pollution control equipment at the locations indicated in the Division-approved spreadsheet is a violation of this regulation.

XII.C.1.d. If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections XII.D., XII.J., and XII.K. it shall 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.

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

XII.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 shall be installed and operational, beginning the date of first production after any new tank installation or tank modification.

XII.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 XII.D.2., auto-igniters shall 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.

XII.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.

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

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

XII.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.

XII.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 shall be employed and operational beginning 180 days from the date of first production 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.

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

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

XII.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 shall be used unless a more specific emission factor has been established pursuant to Section XII.C.2.a.(ii)(B). The Division may require a more specific emission factor that complies with Section XII.C.2.a.(ii)(B).

XII.C.2.a.(ii) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations, a specific emission factor established pursuant to this Section XII.C.2.a.(ii) shall be used. A specific emission factor developed pursuant to Section XII.C.2.a.(ii)(B) may also be used for atmospheric storage tanks at oil and gas exploration and production operations and, once established, or required by the Division, shall be used for such operations.

XII.C.2.a.(ii)(A) 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 XII.C.2.a.(ii)(B) if such a more recent emission factor would be more reliable or accurate.

XII.C.2.a.(ii)(B) Except as otherwise provided in XII.C.2.a.(i), a specific emission factor shall be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of condensate pursuant to a test method approved by the Division.

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

XII.C.2.b.(i) (State Only) For atmospheric condensate storage tanks at oil and gas exploration and production operations, the source shall use a default basin-specific uncontrolled volatile organic compound emission factor established by the Division unless a source-specific emission factor has been established pursuant to Section XII.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 XII.C.2.b.(iii).

XII.C.2.b.(ii) (State Only) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations, the source shall use a source-specific volatile organic compound emission factor established pursuant to Section XII.C.2.b.(iii). If the Division has reason to believe that the source-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 XII.C.2.b.(iii).

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

XII.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 source-specific volatile organic compound emission factor pursuant to Section XII.C.2.b., if such emission factor would be more reliable or accurate.

XII.C.2.b.(iii)(B) (State Only) For atmospheric condensate storage tanks at oil and gas exploration and production operations, the source may use a source-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 condensate pursuant to a test method approved by the Division.

XII.C.2.b.(iii)(C) (State Only) For atmospheric 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 source-specific volatile organic compound emission factor established pursuant to Section XII.C.2.b.

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

XII.C.2.b.(iii)(E) (State Only) A source-specific volatile organic compound emissions factor shall be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of condensate pursuant to a test method approved by the Division.

XII.D. Condensate Storage Tank Emission Controls

The owners and operators of affected operations shall employ air pollution control equipment to reduce emissions of volatile organic compounds from atmospheric condensate storage tanks associated with affected operations by the dates and amounts listed. Emission reductions shall not be required for each and every unit, but instead shall be based on overall reductions in uncontrolled actual emissions from all the atmospheric storage tanks associated with the affected operations for which the owner or operator filed, or was required to file, an APEN pursuant to Regulation Number 3, Part A, due to either having exceeded reporting thresholds or retrofitting with air pollution control equipment in order to comply with system-wide control requirements.

XII.D.1. (State Only) New and Modified Condensate Tanks

Beginning February 1, 2009, owners or operators of any new or modified atmospheric condensate storage tank at exploration and production sites shall collect and control emissions by routing emissions to and operating air pollution control equipment pursuant to Section XII.D. The air pollution control equipment shall have a control efficiency of at least 95%, and shall control volatile organic compounds during the first 90 calendar days after the date of first production after the tank was newly installed, or after the well was newly drilled, re-completed, re-fractured or otherwise stimulated. The air pollution control equipment and associated monitoring equipment required pursuant to Section XII.C.1. may be removed after the first 90 calendar days as long as the source can demonstrate compliance with the applicable system-wide standard.

XII.D.2. System-Wide Control Strategy

XII.D.2.a. The owners and operators of all atmospheric condensate storage tanks that emit greater than or equal to two tons per year of actual uncontrolled volatile organic compounds and are subject to this Section XII.D.2.a. in the 8-hour Ozone Control Area (State Only: or any other specific Ozone Nonattainment area or Attainment/Maintenance Area) shall employ air pollution control equipment to reduce emissions of volatile organic compounds from atmospheric condensate storage tanks by the dates and amounts listed. The dates and requisite reductions are as follows:

XII.D.2.a.(i) For the period May 1 through September 30 of 2005 such emissions shall be reduced by 37.5% from uncontrolled actual emissions on a daily basis.

XII.D.2.a.(ii) For the period of May 1 through September 30 of 2006, such emissions shall be reduced by 47.5% from uncontrolled actual emissions on a daily basis.

XII. D.2.a.(iii) For the period of May 1 through September 30 of each year from 2007 through 2008, such emissions shall be reduced by 75% from uncontrolled actual emissions on a weekly basis.

XII.D.2.a.(iv) Emission reductions achieved between January 1 and April 30, 2005 shall be averaged with emission reductions achieved between October 1 and December 31, 2005. For these two time periods, emissions shall be reduced by 30% from uncontrolled actual emissions and shall be calculated as an average of the emission reductions achieved during the seven months covered by the two periods.

XII.D.2.a.(v) Emission reductions achieved between January 1 and April 30, 2006 shall be averaged with emission reductions achieved between October 1 and December 31, 2006. Emissions shall be reduced by 38% from uncontrolled actual emissions, calculated as an average of the emission reduction achieved during the seven months covered by the two periods.

XII.D.2.a.(vi) For the period between January 1, 2007 and April 30, 2007, such emissions shall be reduced by 38% from uncontrolled actual emissions. For the period between October 1, 2007, and December 31, 2007, such emissions shall be reduced by 60% from uncontrolled actual emissions, calculated for each period as an average of the emission reduction achieved during the months covered by each period.

XII.D.2.a.(vii) Beginning with the year 2008, and each year thereafter, emission reductions achieved between January 1 and April 30 shall be averaged with emission reductions achieved between October 1 and December 31. Emissions shall be reduced by 70% from uncontrolled actual emissions, calculated as an average of the emission reduction achieved during the seven months covered by the two periods with the exception of Sections XII.D.2.a.(viii) through XII.D.2.a.(x).

XII.D.2.a.(viii) For the calendar weeks that include May 1, 2009 through April 30, 2010, such emissions shall be reduced by 81% from uncontrolled actual emissions on a calendar weekly basis from May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

XII.D.2.a.(ix) For the calendar weeks that include May 1, 2010 through April 30, 2011, such emissions shall be reduced by 85% from uncontrolled actual emissions on a calendar weekly basis in the May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

XII.D.2.a.(x) Beginning May 1, 2011 and each thereafter, such emissions shall be reduced by 90% from uncontrolled actual emissions on a calendar weekly basis in the May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

XII.D.2.b. 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 XII.D.2.a., if the following conditions are met:

XII.D.2.b.(i) 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:

XII.D.2.b.(i)(A) A description of the equipment, device or process;

XII.D.2.b.(i)(B) A description of where, when and how the equipment, device or process will be used;

XII.D.2.b.(i)(C) The claimed control efficiency and supporting documentation adequate to demonstrate such control efficiency;

XII.D.2.b.(i)(D) An adequate method for measuring actual control efficiency; and

XII.D.2.b.(i)(E) 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 spreadsheet and annual report required by Sections XII.F.3. and XII.F.4.

XII.D.2.b.(ii) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

XII.D.2.b.(iii) 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.

XII.E. Condensate Storage Tank Monitoring

The owner or operator of any condensate storage tank that is being controlled pursuant to this Section XII. shall inspect or monitor the Air Pollution Control Equipment at least weekly to ensure that it is operating properly.

XII.E.1. Tanks controlled by Air Pollution Control Equipment other than a combustion device shall follow manufacturer's recommended maintenance. Air Pollution Control Equipment shall be periodically inspected to ensure proper maintenance and operation according to the Division-approved operation and maintenance plan.

XII.E.2. The owner or operator of any condensate storage tank that is being controlled pursuant to Section XII. shall inspect or monitor the Air Pollution Control Equipment at least weekly to ensure that it is operating. The inspection shall include the following:

XII.E.2.a. 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;

XII.E.2.b. For combustion devices, a check that the valves for piping of gas to the pilot light are open;

XII.E.2.c. (State Only) In addition to complying with Sections XII.E.2.a. and XII.E.2.b., the owner or operator of tanks subject to the system-wide control strategy under Section XII.D.2.a. that have installed combustion devices may use a surveillance system to maintain records on combustion device operation.

XII.E.3. The owner or operator of all tanks subject to Section XII.D. shall document the time and date of each inspection, the person conducting the inspection, a notation that each of the checks required under this Section XII.E. were completed, description of any problems observed during the inspection, description and date of any corrective actions taken, and name of individual performing corrective actions. Further, all tanks subject to Section XII.D. shall comply with the following:

XII.E.3.a. For combustion devices, the owner or operator shall visually check for and document, on a weekly basis, the presence or absence of smoke;

XII.E.3.b. For vapor recovery units, the owner or operator shall check for and document on a weekly basis that the unit is operating and that vapors from the condensate tank are being routed to the unit;

XII.E.3.c. For all control devices, the owner or operator shall check for and document on a weekly basis that the valves for the piping from the condensate tank to the air pollution control equipment are open;

XII.E.3.d. For all atmospheric condensate storage tanks, the owner or operator shall check for and document on a weekly basis that the thief hatch is closed and latched.

XII.E.3.e. Beginning January 1, 2017, owners or operators of atmospheric condensate storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must conduct and document audio, visual, olfactory ("AVO") inspections of the storage tank at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty one (31) days.

XII.E.4. (State Only) For atmospheric condensate storage tanks equipped with a surveillance system or other Division-approved monitoring system, the owner or operator shall 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.

XII.F. Condensate Storage Tank Recordkeeping and Reporting

The owner or operator of any atmospheric condensate storage tank subject to control pursuant to Section XII.D.2. shall maintain records and submit reports to the Division as required:

XII.F.1. The AIRS number assigned by the Division shall be marked on all condensate storage tanks required to file an APEN.

XII.F.2. If air pollution control equipment is required to comply with Section XII.D.2. visible signage shall be located with the control equipment identifying the AIRS number for each atmospheric condensate storage tank that is being controlled by that equipment.

XII.F.3. Recordkeeping for Tanks Subject to the System-Wide Control Strategy under Section XII.D.2.

The owner or operator shall, at all times, track the emissions and specifically volatile organic compound emissions reductions on a calendar weekly and calendar monthly basis to demonstrate compliance with the applicable emission reduction requirements of Section XII.D.2. This shall be done by maintaining a Division-approved spreadsheet of information describing the affected operations, the air pollution control equipment being used, and the emission reductions achieved, as follows.

XII.F.3.a. The Division-approved spreadsheet shall:

XII.F.3.a.(i) List all atmospheric condensate storage tanks subject to this Section XII by name and AIRS number, or if no AIRS number has been assigned the site location. The spreadsheet also shall list the monthly production volumes for each tank. The spreadsheet shall list the most recent measurement of such production at each tank, and the time period covered by such measurement of production.

XII.F.3.a.(ii) List the emission factor used for each atmospheric condensate storage tank. The emission factors shall comply with Section XII.C.2.

XII.F.3.a.(iii) List the location and control efficiency value for each unit of air pollution control equipment. Each atmospheric condensate storage tank being controlled shall be identified by name and an AIRS number.

XII.F.3.a.(iv) List the production volume for each tank, expressed as a weekly and monthly average based on the most recent measurement available. The weekly and monthly average shall be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the refinery purchaser for delivery of condensate from such tank, over the time such delivered condensate was collected. The weekly and monthly average from the most recent measurement will be used to estimate weekly and monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

XII.F.3.a.(v) Show the calendar weekly and calendar monthly-uncontrolled actual emissions and the calendar weekly and calendar monthly controlled actual emissions for each atmospheric condensate storage tank.

XII.F.3.a.(vi) Show the total system-wide calendar weekly and calendar monthly-uncontrolled actual emissions and the total system-wide calendar weekly and calendar monthly controlled actual emissions.

XII.F.3.a.(vii) Show the total system-wide calendar weekly and calendar monthly percentage reduction of emissions.

XII.F.3.a.(viii) Note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the spreadsheet shall record the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

XII.F.3.a.(ix) Be maintained in a manner approved by the Division and shall include any other information requested by the Division that is reasonably necessary to determine compliance with this Section XII.

XII.F.3.a.(x) Be updated on a calendar weekly and calendar monthly basis and shall be promptly provided by e-mail or fax to the Division upon its request. The U.S. mail may also be used if acceptable to the Division.

XII.F.3.b. Failure to properly install, operate, and maintain air pollution control equipment at the locations indicated in the spreadsheet shall be a violation of this regulation.

XII.F.3.c. A copy of each calendar weekly and calendar monthly spreadsheet shall be retained for five years. A spreadsheet may apply to more than one week if there are no changes in any of the required data and the spreadsheet clearly identifies the weeks it covers. The spreadsheet may be retained electronically. However, the Division may treat any loss of data or failure to maintain the Division-approved spreadsheet, as if the data were not collected.

XII.F.3.d. Each owner or operator shall maintain records of the inspections required pursuant to Section XII.E. and retain those records for five years. These records shall include the time and date of the inspection, the person conducting the inspection, a notation that each of the checks required under Section XII.C. and XII.E. were completed and a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

XII.F.3.e. (State Only) Each owner or operator shall maintain records of required surveillance system or other monitoring data and shall make these records available promptly upon Division request.

XII.F.3.f. (State Only) Each owner or operator shall maintain records on when an atmospheric condensate storage tank is newly installed, or when a well is newly drilled, re-completed, re-fractured or otherwise stimulated. Records shall be maintained per well associated with each tank and the date of first production associated with these activities.

XII.F.4. Reporting for Tanks Subject to the System-Wide Control Strategy under Section XII.D.2.a.

On or before April 30, 2006, and semi-annually by April 30 and November 30 of each year thereafter, each owner or operator shall submit a report using Division-approved format describing the air pollution control equipment used during the preceding calendar year (for the April 30 report) and from May 1 through September 30 (for the November 30 report) and how each company complied with the emission reductions required by Section XII.D.2. during those periods for the 8-hour Ozone Control Area or other specific Ozone Non-attainment or Attainment-Maintenance area. Such reports shall be submitted to the Division on a Division-approved form provided for that purpose.

XII.F.4.a. The report shall list all condensate storage tanks subject or used to comply with Section XII.D.2. and the production volumes for each tank. Production volumes may be estimated by the amounts shown on the receipt from refinery purchasers for delivery of condensate from such tanks.

XII.F.4.b. The report shall list the emission factor used for each tank. The emission factors shall comply with Section XII.C.2.

XII.F.4.c. The report shall list the location and control efficiency value for each piece of air pollution control equipment, and shall identify the atmospheric condensate storage tanks being controlled by each.

XII.F.4.d. The April 30 report shall show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The November 30 report shall show such calendar weekly information for the weeks including May 1st through September 30th only.

XII.F.4.e. The April 30 report shall show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The November 30 report shall show such calendar weekly information for the weeks including May 1st through September 30th only.

XII.F.4.f. The April 30 report shall show the calendar monthly total system-wide percentage reduction of emissions for May 1 through September 30 of the previous year, and for the combined periods of January 1 through April 30 and October 1 through December 31 of the previous year. The November 30 report shall show such calendar weekly information for the weeks including May 1 through September 30 period only.

XII.F.4.g. The report shall note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating should be recorded in the report.

XII.F.4.h. The report shall state whether the required emission reductions were achieved on a weekly basis during the preceding ozone season (calendar weeks including May 1 through September 30) for the November 30 report, and whether the required emission reductions were achieved on a calendar monthly basis during the preceding year for the April 30 report. If the required emission reductions were not achieved, the report shall state why not, and shall identify steps being taken to ensure subsequent compliance.

XII.F.4.i. The report shall include any other information requested by the Division that is reasonably necessary to determine compliance with this Section XII.

XII.F.4.j. A copy of each semi-annual report shall be retained for five years.

XII.F.4.k. In addition to submitting the semi-annual reports, on or before the 30th of each month commencing in June 2007, the owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to Sections XII.A. and XII.D. shall notify the Division of any instances where the air pollution control equipment was not properly functioning during the previous month. The report shall include the time and date that the equipment was not properly operating, the time and date that the equipment was last observed operating properly, and the date and time that the problem was corrected. The report shall also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number of each of the condensate tanks being controlled by the equipment or if no AIRS number has been assigned the site name, and the estimated production from those tanks during the period of non-operation.

XII.F.4.l. Commencing in 2007, on or before April 30 of each year, the owner or operator shall submit a list identifying by name and AIRS number or if no AIRS number has been assigned the site name, each condensate storage tank that is being controlled to meet the requirements set forth in Section XII.D.2. On the 30th of each month during ozone season (May through September) and on November 30 and February 28, the owner or operator shall submit a list identifying any condensate storage tank whose control status has changed since submission of the previous list.

XII.F.4.m. (State Only) Semi-annual report submittals shall be signed by a responsible official who shall also sign the Division-approved compliance certification form for atmospheric condensate storage tanks. The compliance certification shall include both a certification of compliance with all applicable requirements of Section XII. If any non-compliance is identified, citation, dates and durations of deviations from this Section XII., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions shall be identified separately from compliance certifications required under the State Implementation Plan.

XII.F.4.n. (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section XII. shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

XII.F.5. The record-keeping and reporting required in Section XII. shall not apply to the owner or operator of any natural gas compressor station or natural gas drip station that is authorized to operate pursuant to a construction permit or Title V operating permit issued by the Division if the following criteria are met:

XII.F.5.a. Such permits are obtained by the owner or operator on or after the effective date of this provision and contain the provisions necessary to ensure the emissions reductions required by Section XII.D;

XII.F.5.b. The owners and operators of such natural gas compressor stations or natural gas drip stations do not own or operate any exploration and production operation(s); and

XII.F.5.c. Total emissions from atmospheric condensate storage tanks associated with such natural gas compressor stations or drip stations subject to APEN reporting requirements under Regulation Number 3, Part A owned or operated by the same person do not exceed 30 tons per year in the 8-hour Ozone Control Area.

XII.G. Natural gas-processing plants located in the 8-hour Ozone Control Area (State Only: or any specific Ozone Nonattainment or Attainment/Maintenance Area) shall comply with requirements of this Section XII.G., as well as the requirements of Sections XII.B., XII.C.1.a., XII.C.1.b., XII.H., XII.J., XII.K., and XVI.

XII.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).

XII.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%.

XII.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 XII.G. beginning January 1, 2019. (State Only: Existing natural gas processing plants within any new Ozone Nonattainment or Attainment/Maintenance Area shall comply with this regulation within three years after the nonattainment designation.)

XII.G.4. The provisions of Sections XII.B., XII.C.1.a., XII.C.1.b., XII.G., XII.H., XII.J., XII.K., and XVI., apply upon the commencement of operations to any natural gas processing plant that commences operation in the 8-Hour Ozone Control Area or Ozone Nonattainment (State Only: or Attainment/Maintenance Area) after the effective date of this section.

XII.H. Emission Reductions from glycol natural gas dehydrators

XII.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 XII.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.

XII.H.2. (State Only) Beginning January 30, 2009, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in any Ozone Nonattainment or Attainment/Maintenance Area and subject to control requirements pursuant to Section XII.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.

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

XII.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

XII.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.

XII.H.4. For purposes of Section XII.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.

XII.H.5. Monitoring and recordkeeping

XII.H.5.a. Beginning January 1, 2017, owners or operators of glycol natural gas dehydrators subject to the control requirements of Sections XII.H.1. or XII.H.2. must check on a weekly basis that any condenser or air pollution control equipment used to control emissions of volatile organic compounds is operating properly, and document:

XII.H.5.a.(i) The date of each inspection;

XII.H.5.a.(ii) A description of any problems observed during the inspection of the condenser or air pollution control equipment; and

XII.H.5.a.(iii) A description and date of any corrective actions taken to address problems observed during the inspection of the condenser or air pollution control equipment.

XII.H.5.b. The owner or operator must check and document on a weekly basis that the pilot light on a combustion device is lit, that the valves for piping of gas to the pilot light are open, and visually check for the presence or absence of smoke.

XII.H.5.c. The owner or operator must document the maintenance of the condenser or air pollution control equipment, consistent with manufacturer specifications or good engineering and maintenance practices.

XII.H.5.d. The owner or operator must retain records for a period of five years and make these records available to the Division upon request.

XII.H.6. Reporting

XII.H.6.a. On or before November 30, 2017, and semi-annually by April 30 and November 30 of each year thereafter, the owner or operator must submit the following information for the preceding calendar year (April 30 report) and for May 1 through September 30 (November 30 report) using Division-approved format:

XII.H.6.a.(i) A list of the glycol natural gas dehydrator(s) subject to Section XII.H.;

XII.H.6.a.(ii) A list of the condenser or air pollution control equipment used to control emissions of volatile organic compounds from the glycol natural gas dehydrator(s); and

XII.H.6.a.(iii) The date(s) of inspection(s) where the condenser or air pollution control equipment was found not operating properly or where smoke was observed.

XII.I. The requirements of Sections XII.C. through XII.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:

XII.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;

XII.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 XII.C.1.a. and XII.C.1.b;

XII.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

XII.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:

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

XII.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;

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

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

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

XII.J. Compressors

XII.J.1. Centrifugal compressor

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

XII.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.

XII.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.

XII.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.

XII.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.

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

XII.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.

XII.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.

XII.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.

XII.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.

XII.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.

XII.J.1.h. Recordkeeping

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

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

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

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

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

XII.J.1.i. As an alternative to the inspection, repair, and recordkeeping provisions in Sections XII.J.1.c. through XII.J.1.f., XII.J.1.h.(i)(C), and XII.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 XII.L., including the inspection frequency.

XII.J.1.j. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections XII.J.1.a. through XII.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.

XII.J.2. Reciprocating compressor

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

XII.J.2.a.(i) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed before January 1, 2018, must

XII.J.2.a.(i)(A) Begin monitoring the hours of operation starting January 1, 2018; or

XII.J.2.a.(i)(B) Conduct the first rod packing replacement required under Section XII.J.2. prior to January 1, 2021.

XII.J.2.a.(ii) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed after January 1, 2018, must begin monitoring the hours or months of operation upon commencement of operation of the reciprocating compressor.

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

XII.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.

XII.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.

XII.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.

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

XII.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.

XII.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.

XII.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.

XII.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.

XII.J.2.c. Recordkeeping

XII.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:

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

XII.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;

XII.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;

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

XII.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.

XII.J.2.d. As an alternative to the inspection, repair, and recordkeeping provisions in Sections XII.J.2.b., XII.J.2.c.(i)(D), and XII.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 XII.L., including the inspection frequency.

XII.J.2.e. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections XII.J.2.a. through XII.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.

XII.K. Pneumatic pumps

XII.K.1. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a natural gas processing plant must ensure the pneumatic pump has a volatile organic compound emission rate of zero.

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

XII.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.

XII.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.

XII.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.

XII.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.

XII.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.

XII.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.

XII.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.

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

XII.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.

XII.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.

XII.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.

XII.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.

XII.K.3. Recordkeeping

XII.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:

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

XII.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;

XII.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;

XII.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;

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

XII.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.

XII.K.4. As an alternative to the inspection, repair, and recordkeeping provisions in Sections XII.K.2.e. through XII.K.2.h., XII.K.3.a.(v), and XII.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 XII.L., including the inspection frequency.

XII.K.5. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections XII.K.1. through XII.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.

XII.L. Leak detection and repair program for well production facilities and natural gas compressor stations located in the 8-hour Ozone Control Area.

XII.L.1. Natural gas compressor stations

XII.L.1.a. Beginning June 30, 2018, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least quarterly.

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

XII.L.2. Well production facilities

XII.L.2.a. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year must inspect components for leaks using an approved instrument monitoring method at least annually.

XII.L.2.b. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

XII.L.2.c. For purposes of Sections XII.L.2.a. and XII.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).

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

XII.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.

XII.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.

XII.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.

XII.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.

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

XII.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.

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

XII.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 XII.L.8.

XII.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 XII.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 XII.L.4.a., the leak must be repaired and remonitored in accordance with Section XII.L.5.

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

XII.L.5. Repair and remonitoring

XII.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.

XII.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.

XII.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.

XII.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.

XII.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.

XII.L.5.c. Leaks discovered pursuant to the leak detection methods of Section XII.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 XII.L.5. or keep required records in accordance with Section XII.L.6.

XII.L.6. Recordkeeping

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

XII.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;

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

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

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

XII.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;

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

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

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

XII.L.7. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XII.L. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

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

XII.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;

XII.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 XII.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;

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

XII.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 XII.L.7.b. or natural gas compressor station, and the basis for each delay of repair;

XII.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

XII.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.

XII.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 XII.L., if the following conditions are met:

XII.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:

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

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

XII.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;

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

XII.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);

XII.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;

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

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

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

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

XII.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 XII.L.

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

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

XII.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.

XIII. Graphic Arts and Printing

XIII.A. Packaging Rotogravure, Publication Rotogravure, and Flexographic Printing

XIII.A.1. Definitions

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

XIII.A.1.a. "Flexographic Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique in which the pattern to be applied is raised above the printing roll and the image carrier is made of rubber or other elastomeric materials.

XIII.A.1.b. "Packaging Rotogravure Printing" means rotogravure printing upon paper, paperboard, metal foil, plastic film, and other substrates, which are, in subsequent operations, formed into packaging products and labels for articles to be sold.

XIII.A.1.c. "Publication Rotogravure Printing" means rotogravure printing upon paper, which is subsequently formed into books, magazines, catalogues, brochures, directories, newspaper supplements, and other types of printed materials.

XIII.A.1.d. "Roll Printing" means the application of words, designs, and pictures to a substrate usually by means of a series of hard rubber or steel rolls each with only partial coverage.

XIII.A.1.e. "Rotogravure Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique, which involves an intaglio or recessed image areas in the form of cells.

XIII.A.2. Applicability

XIII.A.2.a. This section applies to all packaging rotogravure, publication rotogravure, and flexographic printing facilities whose potential emissions of volatile organic compounds before control (determined at design capacity and 8760 hrs/year, or at maximum production, and accounting for any capacity or production limitations in a federally-enforceable permit) are equal to or more than 90,000 Kg per year (100 tons/year). Potential emissions are to be estimated by extrapolating historical records of actual consumption of solvent and ink. (e.g., the historical use of 20 gallons of ink for 4,000 annual hours would be extrapolated to 43.8 gallons for 8760 hours.)The before-control volatile organic compound emissions calculations shall be the summation of all volatile organic compounds in the inks and solvents (including cleaning liquids) used.

XIII.A.3. Provisions for Specific Processes

XIII.A.3.a. No owner or operator of a facility subject to this section and employing VOC-containing ink shall operate, cause, allow, or permit the operation of the facility unless:

XIII.A.3.a.(i) The volatile fraction of ink, as it is applied to the substrate, contains 25.0 percent or less (by volume) of VOC and 75.0 percent or more (by volume) of water; or

XIII.A.3.a.(ii) The ink (minus water) as it is applied to the substrate, contains 60.0 percent or more (by volume) non-volatile material; or

XIII.A.3.a.(iii) The owner or operator installs and operates a control device and capture system in accordance with Sections XIII.A.3.b. and XIII.A.3.c.; or

XIII.A.3.a.(iv) A combination of solvent-borne inks and low solvent inks that achieve a 70% (volume) overall reduction of solvent usage (compared to an all solvent borne ink usage) is used; or

XIII.A.3.a.(v) Flexographic and packaging rotogravure printing facilities limit emissions to 0.5 pounds of VOC per pound of solids in the ink. The limit includes all solvent added to the ink: solvent in the purchased ink, solvent added to cut the ink to achieve desired press viscosity, and solvent added to ink on the press to maintain viscosity during the press run. (Publication rotogravure facilities shall not use this option); or

XIII.A.3.a.(vi) Crossline averaging is used. The requirements of Section IX.A.5.d. apply.

XIII.A.3.b. A capture system shall be used in conjunction with the emission control system in Section XIII.A.3.a. The design and operation of a capture system shall be consistent with good engineering practice, and in conjunction with control equipment shall be required to provide for an overall reduction in volatile organic compound emissions of at least:

XIII.A.3.b.(i) 75.0 percent where a publication rotogravure process is employed;

XIII.A.3.b.(ii) 65.0 percent where a packaging rotogravure process is employed; or

XIII.A.3.b.(iii) 60.0 percent where a flexographic printing process is employed.

XIII.A.3.c. The design, operation, and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Testing of any capture system may be required by the Division on a case-by-case basis, in cases where a total enclosure is not used or when material balance results are questionable. Testing of capture system efficiency shall meet the requirements of Section IX.A.5.e.

XIII.A.3.d. The overall reduction in VOC emissions specified in Section XII.A.3.b. shall be calculated by material balance methods approved by the Division, or by determination of capture and control device efficiencies. The overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

XIII.A.4. Testing and Monitoring

The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Section IX.A.3., IX.A.7, IX.A.9., and IX.A.10. In Section IX.A.3., EPA reference method 24A shall be the test method used for publication rotogravure inks, while EPA Reference method 24 data is acceptable for all other inks. Test methods as set forth in Appendix A, Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR), in effect July 1, 1993.

XIII.A.5. The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Section IX.A.8. “A Guideline for Graphic Arts Calculations” shall be used for compliance determination.

XIII.B. Lithographic and Letterpress Printing

XIII.B.1. General Provisions

XIII.B.1.a. Definitions

XIII.B.1.a.(i) “Alcohol” means any of the hydroxyl-containing organic compounds with a molecular weight equal to or less than 74.12, which includes methanol, ethanol, propanol, and butanol.

XIII.B.1.a.(ii) “Alcohol substitute” means nonalcohol additives that contain VOCs and are used in the fountain solution to reduce the surface tension of water or prevent ink piling.

XIII.B.1.a.(iii) “Cleaning material” means a VOC-containing material used to remove ink and debris from the printing press area, operating surfaces of the printing press and, printing press parts. Blanket wash is a type of cleaning material.

XIII.B.1.a.(iv) “Composite partial vapor pressure” means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the "i"th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the "i"th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

XIII.B.1.a.(v) "Fountain solution" means a mixture of water, nonvolatile printing chemicals, and a liquid additive that reduces the surface tension of the water so that it spreads easily across the printing plate surface. The fountain solution wets the non-image areas so that the ink is maintained within the image areas.

XIII.B.1.a.(vi) "Heatset" means any lithographic or letterpress printing operation where printing inks are set by the evaporation of the ink oils in a heatset dryer.

XIII.B.1.a.(vii) "Heatset dryer" means a hot air dryer used in heatset lithography to heat the printed substrate and to promote the evaporation of ink oils.

XIII.B.1.a.(viii) "Lithographic printing" means a planographic printing process where the image and non-image areas are chemically differentiated (the image area is oil receptive and the non-image area is water receptive). This printing process differs from other conventional printing methods, where the image is a raised or recessed surface.

XIII.B.1.a.(ix) "Letterpress printing" means a printing process in which the image area is raised relative to the non-image area and the paste ink is transferred to the substrate directly from the image surface.

XIII.B.1.a.(x) "Non-heatset" means any printing operation where the printing inks are set without the use of heat. For the purpose of Section XIII.B., ultraviolet-cured and electron beam-cured inks are considered non-heatset.

XIII.B.1.a.(xi) "Offset lithographic printing" means a printing process that transfers the ink film from the lithographic plate to an intermediary surface (blanket), which in turn transfers the ink film to the substrate.

XIII.B.1.a.(xii) "Press" means a printing production assembly composed of one or more print units used to produce a printed substrate including any associated coating, spray powder application, heatset web dryer, ultraviolet or electron beam curing units, or infrared heating units.

XIII.B.1.a.(xiii) "Sheet-fed printing" means a printing process where individual sheets of paper or substrate are fed into the printing press.

XIII.B.1.a.(xiv) "Web printing" means a printing process where continuous rolls of substrate material are fed to the press and rewound or cut to size after printing.

XIII.B.1.b. Applicability

XIII.B.1.b.(i) The provisions of this Section XIII.B. apply to fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses. These materials are not subject to the requirements of Sections IX. and X.

XIII.B.1.b.(ii) The work practice requirements in Section XIII.B.1.c. apply to all lithographic and letterpress printing operations.

XIII.B.1.b.(iii) The VOC content limit for inks in Section XIII.B.1.d. applies to lithographic and letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

XIII.B.1.b.(iv) The cleaning material requirements in Section XIII.B.2. apply to letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

XIII.B.1.b.(v) The cleaning material and fountain solution requirements in Sections XIII.B.2. and XIII.B.3. apply to offset lithographic printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

XIII.B.1.b.(vi) The control requirements in Section XIII.B.4. apply to each heatset web offset lithographic and heatset web letterpress printing press with the potential to emit from the dryer, prior to controls, at least 25 tons per calendar year of VOC (petroleum ink oil) from heatset inks.

XIII.B.1.c. Work Practice Requirements

Lithographic and letterpress printing operations must implement the following work practices at all times to reduce VOC emissions from fugitive sources:

XIII.B.1.c.(i) Cover open containers and keep cleaning materials in closed containers when not in use;

XIII.B.1.c.(ii) Properly dispose of used cleaning materials, fountain solutions, and used shop towels; and

XIII.B.1.c.(iii) Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintain cleaning equipment to repair cleaning materials leaks.

XIII.B.1.d. VOC Content Limit for Inks

XIII.B.1.d.(i) Lithographic and letterpress printing operations, excluding heatset web offset and heatset web letterpress printing operations, must use low-VOC inks, which average less than 30% (by weight) VOC on a monthly basis.

XIII.B.1.d.(ii) Heatset web offset lithographic and heatset web letterpress printing operations must use low-VOC inks, which average less than 40% (by weight) VOC on a monthly basis.

XIII.B.2. Offset lithographic printing and letterpress printing operations must comply with the following cleaning materials requirements;

XIII.B.2.a. All cleaning materials must contain less than 70% (by weight) VOC or have a VOC composite vapor pressure less than 10 mmHg at 20°C.

XIII.B.2.b. Exemptions

The following materials and operations are exempt from the cleaning material requirements in Section XIII.B.2.a.:

XIII.B.2.b.(i) Cleaners used on electronic components of a press.

XIII.B.2.b.(ii) Pre-press cleaning operations.

XIII.B.2.b.(iii) Post-press cleaning operations.

XIII.B.2.b.(iv) Floor cleaning supplies (other than those used to clean dried ink).

XIII.B.2.b.(v) Cleaning performed in parts washers or cold cleaners that are subject to Section V.

XIII.B.2.c. Use of non-compliant cleaning materials

Cleaning materials not meeting the limits in Section XIII.B.2.a. are limited to less than or equal to 110 gallons per calendar year.

XIII.B.3. Offset lithographic printing operations must comply with the following fountain solution requirements:

XIII.B.3.a. Heatset web offset lithographic printing operations must:

XIII.B.3.a.(i) Use a fountain solution containing 1.6% alcohol (by weight) or less as applied;

XIII.B.3.a.(ii) Use a fountain solution containing 3% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

XIII.B.3.a.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

XIII.B.3.b. Sheet-fed printing operations must

XIII.B.3.b.(i) Use a fountain solution containing 5% alcohol (by weight) or less as applied;

XIII.B.3.b.(ii) Use a fountain solution containing 8.5% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

XIII.B.3.b.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

XIII.B.3.b.(iv) The following are exempt from the fountain solution requirements in Section XIII.B.3.b.:

XIII.B.3.b.(iv)(A) Fountain solution use associated with a sheet-fed printing press with maximum sheet size 11x17 inches or smaller.

XIII.B.3.b.(iv)(B) Fountain solution use associated with a sheet-fed printing press having a total fountain solution reservoir less than one (1) gallon.

XIII.B.3.c. Non-heatset web printing must use a fountain solution containing 5% alcohol substitute (by weight) or less and no alcohol.

XIII.B.4. Heatset web offset lithographic and heatset web letterpress printing operations must comply with the following control requirements:

XIII.B.4.a. Heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 90% or greater.

XIII.B.4.b. If the control device was first installed on or after January 1, 2017, heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 95% or greater.

XIII.B.4.c. Where inlet VOC concentration is low and a 90 or 95% control efficiency is not achievable due to low inlet concentrations or measurable due to equipment configuration, heatset web offset lithographic and heatset web letterpress printing operations may reduce the control device outlet concentration to 20 ppmv (as hexane on a dry basis).

XIII.B.4.d. The following are exempt from the control requirements in Section XIII.B.4.:

XIII.B.4.d.(i) Heatset presses used for book printing.

XIII.B.4.d.(ii) Heatset presses with maximum web width of 22 inches or less.

XIII.B.4.d.(iii) Waterborne or radiation (ultra-violet or electron beam) cured materials that are not heatset.

XIII.B.5. Monitoring, Recordkeeping and Reporting

XIII.B.5.a. The owner or operator of a heatset web offset lithographic or heatset web letterpress printing operation required to demonstrate compliance with Section XIII.B.4. must install, calibrate, maintain, and operate a temperature monitoring device, according to the manufacturer's specifications.

XIII.B.5.b. The owner or operator of a lithographic and letterpress printing operations subject to Sections XIII.B.1.d. and XIII.B.2. through XIII.B.4. must keep the following records for two (2) years and make them available for inspection by the Division upon request:

XIII.B.5.b.(i) If applicable, records demonstrating that a listed exemption to this Section XIII.B. applies.

XIII.B.5.b.(ii) If applicable, monthly records of the type, alcohol content or alcohol substitute content, and total volume of fountain solution used in printing operations.

XIII.B.5.b.(iii) If applicable, monthly records of the type, VOC content or composite vapor pressure, and total volume of the cleaning materials used in printing operations.

XIII.B.5.b.(iv) If applicable, monthly records of the type, VOC content, and total volume of inks (including varnishes) and coatings used in printing operations.

XIII.B.5.b.(v) If applicable, monthly records demonstrating compliance with the control requirements in Section XIII.B.4.

XIII.B.5.b.(vi) Records of calendar year VOC emission estimates demonstrating whether the printing operation meets or exceed the applicability thresholds in Section XIII.B.1.b.

XIII.B.5.c. Compliance with control requirements must be demonstrated using the following methods as applicable:

XIII.B.5.c.(i) Safety data sheets or other analytical data from the ink, cleaning material, or fountain solution manufacturer to demonstrate compliance with VOC content limit for inks in Section XIII.B.1.d., the cleaning material requirements in Section XIII.B.2., and the fountain solution requirements in Section XIII.B.3.;

XIII.B.5.c.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with the control equipment requirements in Section XIII.B.4.; or

XIII.B.5.c.(iii) A performance test conducted during representative conditions using one of the following methods as applicable:

XIII.B.5.c.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) to determine VOC content for inks, fountain solutions and cleaning materials; or

XIII.B.5.c.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) to determine control efficiency or outlet concentration of the emission control equipment.

XIV. Pharmaceutical Synthesis

XIV.A. General Provisions

XIV.A.1. Applicability

This section applies to all sources of volatile organic compounds associated with pharmaceutical manufacturing activities, including, but not limited to, reactors, distillation units, dryers, storage of VOCs, extraction equipment, filters, crystallizers, and centrifuges.

XIV.A.2. Exemptions

Extraction of organic substances from animal or vegetable material; fermentation and culturing; formulation and packaging of pharmaceutical or medicinal products.

XIV.A.3. Definitions

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

XIV.A.3.a. “Control System” means any number of control devices, including condensers, which are designed and operated to reduce the quantity of VOC emitted to the atmosphere.

XIV.A.3.b. “Pharmaceutical” means a medicine or drug which appears in the United States Pharmacopoeia National Formulary, or which is so designated by the National Drug Code of the United States FDA Bureau of Drugs.

XIV.A.3.c. “Production Equipment Exhaust System” means a device for collecting and directing out of the work area VOC fugitive emissions from reactor openings, centrifuge openings, and other vessel openings for the purpose of protecting workers from excessive VOC exposure.

XIV.A.3.d. “Reactor” means a vat or vessel, which may be jacketed to permit temperature control, designed to contain chemical reactions.

XIV.A.3.e. “Separation Operation” means a process that separates a mixture of compounds and solvents into two or more components. Specific mechanisms include, but are not limited to, extraction, centrifugation, filtration, distillation, and crystallization.

XIV.A.3.f. “Synthesized Pharmaceutical Manufacturing” means manufacture of pharmaceutical products by chemical synthesis. It includes the manufacture of chemical intermediates (of sufficient purity) which are typically used by the pharmaceutical industry as precursors to finished mixtures of chemicals. (Thus, it excludes those chemical processes which are not directed at creating finished pharmaceutical or chemical intermediates to finished pharmaceuticals.)

XIV.B. Provisions for Specific Processes

XIV.B.1. The owner or operator of a facility subject to this section shall control the volatile organic compound emissions from each vent which has the potential to emit 6.80 kg/day (l5 lb./day) or more of VOC from reactors, distillation operations, crystallizers, centrifuge and vacuum dryers. Surface condensers or equivalent controls shall be used, provided that, if surface condensers are used, the condenser outlet gas temperature shall not exceed the following values:

VOCs True Vapor Pressure* at 20° in torr (and psia) from (minimum) up to ** (maximum)	Maximum temperature of Gas Stream immediately exiting the condenser
0-26(0-0.5)	35°C (95°F)
26-52(0.5-1.0)	25°C(77°F)
52-78(1.0-1.5)	10°C(50°F)
78-150(1.5-2.9)	0°C(32°F)
150-300(2.9-5.8)	-15°C(5°F)
Greater than 300(Greater than 5.8)	-25°C(-13°F)

*The calculation methods for gases containing more than one condensable component are complex. As a simplification, the temperature necessary for control by condensation can be roughly approximated by the weighted average of the temperatures necessary for condensation of each VOC considered separately but at concentrations equal to the total organic concentration.

**But not including the maximum value of the range.

XIV.B.2. Division approval shall be required for control equipment used to control VOCs of 570 torr (11 psia) and above.

XIV.B.3. The owner or operator of a facility subject to this section shall reduce the VOC emissions from each air dryer and production equipment exhaust system:

XIV.B.3.a. By at least 90 percent if emissions are 150 kg/day (330 lbs/day) or more of VOC, or,

XIV.B.3.b. To 15.0 kg/day (33 lb/day) or less if emissions are less than 150 kg/day (330 lb/day) of VOC.

XIV.B.4. The owner or operator of a facility subject to this section shall:

XIV.B.4.a. Provide a vapor balance system or equivalent control that is at least 90.0 percent effective in reducing emissions from truck or railcar deliveries to storage tanks with capacities greater than 7,570 liters (2,000 gallons) that store VOC with true vapor pressure greater than 210 torr (4.1 psia) at 20°C; and,

XIV.B.4.b. Install pressure/vacuum conservation vents set at plus or minus 0.2 kPa on all storage tanks that store VOC with true vapor pressures greater than 10.0 kPa (1.5 psi) at 20°C.

XIV.B.5. The owner or operator of a facility subject to this section shall enclose all centrifuges, rotary vacuum filters, and other filters having an exposed liquid surface, where the liquid contains VOC and exerts a total VOC true vapor pressure of 26 torr (0.5 psia) or more at 20°C.

XIV.B.6. The owner or operator of a synthesized pharmaceutical facility subject to this section shall install covers on all in-process tanks containing a volatile organic compound at any time. These covers shall remain closed unless sampling, maintenance, short-duration production procedures or inspection procedures require access.

XIV.B.7. The owner or operator of a facility subject to this section shall repair all leaks from which a liquid, containing VOC, can be observed running or dripping. The repair shall be completed the first time the equipment is off-line for a period of time long enough to complete the repair, except that no leak shall go unrepaired for more than 14 days after initial detection unless the Division issues written approval.

XIV.B.8. Each surface condenser shall have at least one temperature indicator with its sensor located in the outlet gas stream.

XIV.C. Testing and Monitoring

XIV.C.1. Sources subject to the requirements of this section are also subject to the requirements of Sections IX.A.3., IX.A.7., IX.A.8., and IX.A.9.

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

XV.A. General Provisions

XV.A.1. Applicability

This section is applicable to all gasoline terminals, gasoline bulk plants and gasoline dispensing facilities (e.g., service stations) which are located in ozone nonattainment areas and which must have a vapor collection and/or a vapor control system pursuant to Section VI. and other applicable rules.

XV.A.2. Exemptions

This section is not applicable to those operations involving transfer of gasoline from gasoline dispensing facilities to motor vehicle fuel tanks nor to other dispensing operations at such facilities.

XV.A.3. Definitions

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

XV.A.3.a. “Gasoline Dispensing Facility” means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks, (e.g., service stations, fleet pumps, etc.)

XV.A.3.b. “Gasoline Transport Truck” means tank trucks or trailers equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants or gasoline terminals.

XV.A.3.c. “Vapor Collection System” means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor control system or vapor holding tank.

XV.A.3.d. "Vapor Control System" means a system that is designed to control the release of volatile organic compounds displaced from a vessel during transfer of gasoline.

XV.B. Specific Provisions

XV.B.1. The operator of a vapor collection or vapor control system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents:

XV.B.1.a. Gauge pressure from exceeding 33.6 torr (18 inches of H2O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H2O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility.

XV.B.1.b. A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants and terminals.

XV.B.1.c. Avoidable liquid leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

XV.B.1.d. Division representatives shall monitor for excessive back pressure and vapor leakage as is defined by Sections XV.B.1.a. and XV.B.1.b.

XV.B.2. Repairs and Modifications

XV.B.2.a. The operator shall within fifteen (15) days, repair and retest a vapor collection or control system that exceeds the pressure limits (Section XV.B.1.a.), excepting that;

XV.B.2.b. Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion.

XVI. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area

XVI.A Requirements for new and existing engines.

XVI.A.1. The owner or operator of any natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower commencing operations in the 8-hour Ozone Control Area on or after June 1, 2004 shall employ air pollution control technology to control emissions, as provided in Section XVI.B.

XVI.A.2. Any existing natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower, which existing engine was operating in the 8-hour Ozone Control Area prior to June 1, 2004, shall employ air pollution control technology on and after May 1, 2005, as provided in Section XVI.B.

XVI.B. Air pollution control technology requirements

XVI.B.1. For rich burn reciprocating internal combustion engines, a non-selective catalyst reduction and an air fuel controller shall be required. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVI.B.2. For lean burn reciprocating internal combustion engines, an oxidation catalyst shall be required. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVI.B.3. The emission control equipment required by this Section XVI.B shall be appropriately sized for the engine and shall be operated and maintained according to manufacturer specifications.

XVI.C. The air pollution control technology requirements in Sections XVI.A. and XVI.B. do not apply to:

XVI.C.1. Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31.

XVI.C.2. Reciprocating internal combustion engines that the Division has determined will be permanently removed from service or replaced by electric units on or before May 1, 2007. The owner or operator of such an engine shall provide notice to the Division of such intent by May 1, 2005 and shall not operate the engine identified for removal or replacement in the 8-hour Ozone Control Area after May 1, 2007.

XVI.C.3. Any emergency power generator exempt from APEN requirements pursuant to Regulation Number 3, Part A.

XVI.C.4. Any lean burn reciprocating internal combustion engine operating in the 8-hour Ozone Control Area prior to June 1, 2004, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $5,000 per ton of VOC emission reduction. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by May 1, 2005. Any reciprocating internal combustion engine qualifying for this exemption shall not be moved to any other location within the 8-hour Ozone Control Area.

XVI.D. Requirements for major sources of NOx

XVI.D.1. Applicability. Except as provided in Section XVI.D.2., the requirements of this Section XVI.D. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx as of June 3, 2016 located in the 8-Hour Ozone Control Area.

XVI.D.2. Exemptions. The following stationary combustion equipment are exempt from the emission limitation requirements of Section XVI.D.4., the compliance demonstration requirements in Section XVI.D.5., and the related recordkeeping and reporting requirements of Sections XVI.D.7.a-f. and XVI.D.8, but these sources must maintain any and all records necessary to demonstrate that an exemption applies. These records must be maintained for a minimum of five years and made available to the Division upon request. Qualifying for an exemption in this section does not preclude the combustion process adjustment requirements of Section XVI.D.6., when required by XVI.D.6.a.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of this Section XVI.D. as expeditiously as practicable but no later than 36 months after any exemption no longer applies. Additionally, once stationary combustion equipment that is not equipped with CEMS or CERMS no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations of Section XVI.D.4.

XVI.D.2.a. Any stationary combustion equipment whose utilization is less than:

XVI.D.2.a.(i) 20% of its capacity factor on an annual average basis over a 3-year rolling period for boilers; or

XVI.D.2.a.(ii) 10% of its capacity factor on an annual average basis over a 3-year rolling period for stationary combustion turbines and compression ignition reciprocating internal combustion engines.

XVI.D.2.b. An engine testing operation or process line.

XVI.D.2.c. Any gaseous fuel fired stationary combustion equipment used to control VOC emissions from a commercial or industrial process.

XVI.D.2.d. Any stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx on a calendar year basis.

XVI.D.2.e. Any natural gas-fired reciprocating internal combustion engines subject to a work practice or emission control requirement contained in this Regulation 7, Section XVI.A. or B.

XVI.D.2.f. Any stationary combustion equipment subject to a federally enforceable work practice or emission control requirement contained in this Regulation 7, Section XIX.A.-D or Regulation 3, Part F.

XVI.D.3. Definitions

XVI.D.3.a. “Affected unit” means any stationary combustion equipment that is subject to or becomes subject to an emission limitation in Section XVI.D.4.

XVI.D.3.b. “Boiler” means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

XVI.D.3.c. “Capacity factor” means the ratio of the amount of fuel burned by an emissions unit in a calendar year to the amount of fuel it could have burned if it had operated at the designed heat input rating for 8,760 hours during the calendar year. Alternatively, for electric generating units, capacity factor can mean the ratio of the unit’s actual annual electric output (expressed in MWe/hr) to the electric output the unit could have achieved if it operated at its nameplate capacity (or maximum observed hourly gross load (expressed in MWe/hr) if greater than the nameplate capacity) for 8,760 hours during the calendar year.

XVI.D.3.d. "Continuous emission monitoring system" ("CEMS") or "Continuous emission rate monitoring system" ("CERMS") means the total equipment required to sample, condition (if applicable), analyze, and provide a written record of such emissions and/or emission rates, expressed on a continuous basis in terms of an applicable emission limitation. Such equipment includes, but is not limited to, sample collection and calibration interfaces, pollutant analyzers, a diluent analyzer (oxygen or carbon dioxide), stack gas volumetric flow monitors (if appropriate for CERMS), and data recording and storage devices.

XVI.D.3.d. "Compression ignition reciprocating internal combustion engine (RICE)" means a type of stationary RICE that is liquid fuel-fired and not ignited with a spark plug or other sparking device.

XVI.D.3.e. "Digester gas" means any gaseous byproduct of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide.

XVI.D.3.f. "Duct burner" means a device that combusts fuel and is placed in the exhaust duct from another source (e.g., stationary combustion turbine, internal combustion engine, or kiln) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

XVI.D.3.g. "Gaseous fuel" means natural gas, landfill gas, refinery fuel gas, digester gas, methane, ethane, propane, butane, or any gas stored as a liquid at high pressure such as liquefied petroleum gas.

XVI.D.3.h. "Glass melting furnace" means an emissions unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass.

XVI.D.3.i. "Kiln" means the equipment used to remove combined (chemically bound) water and/or gases from mineral material through direct or indirect heating.

XVI.D.3.j. "Lightweight aggregate" means the expanded, porous product from heating shales, clays, slates, slags, or other natural materials in a kiln.

XVI.D.3.k. "Liquid fuel" means any fuel which is a liquid at standard conditions including but not limited to distillate oils, kerosene and jet fuel. Liquefied gaseous fuels are not liquid fuels.

XVI.D.3.l. "Process heater" means an enclosed device using controlled flame and a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

XVI.D.3.m. "Reciprocating internal combustion engine" means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not used to propel a motor vehicle or a vehicle used solely for competition.

XVI.D.3.n. "Stationary combustion equipment" means an emissions unit that combusts solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use. Stationary combustion equipment includes, but is not limited to, boilers, duct burners, engines, glass melting furnaces, kilns, process heaters and stationary combustion turbines.

XVI.D.3.o. "Stationary combustion turbine" means a non-mobile, enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine. Stationary combustion turbines can be simple cycle or combined cycle and they may or may not include a duct burner.

XVI.D.4. Emission limitations. By October 1, 2021, no owner or operator of stationary combustion equipment may cause, allow or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section XVI.D.5.a.(i), the following emission limitations are on a 30-day rolling average basis.

XVI.D.4.a. Boilers

XVI.D.4.a.(i) For a gaseous fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

XVI.D.4.a.(ii) For a liquid fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

XVI.D.4.a.(iii) Boilers subject to the categorical limits in Section XVI.D.4.a.(i) or (ii) with a maximum design heat input capacity less than 100 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section XVI.D.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section XVI.D.6.a.

XVI.D.4.b. Stationary combustion turbines

XVI.D.4.b.(i) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction on or before February 18, 2005 must comply with the applicable NOx emission limits in 40 CFR Part 60, Subpart GG (July 1, 2017).

XVI.D.4.b.(ii) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction, modification or reconstruction after February 18, 2005 must comply with the applicable NOx emission limits in 40 CFR Part 60, Subpart KKKK (July 1, 2017).

XVI.D.4.b.(iii) Stationary combustion turbines subject to the categorical limits in Section XVI.D.4.b.(i) or (ii) above and stationary combustion turbines with a maximum design heat input capacity less than 10 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section XVI.D.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section XVI.D.6.a.

XVI.D.4.c. Lightweight aggregate kilns. For lightweight aggregate kilns with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr, 56.6 pounds of NOx per hour.

XVI.D.4.d. Glass melting furnaces

XVI.D.4.d.(i) For, glass melting furnaces, 1.2 pounds of NOx per ton of glass pulled. However, days in which a glass melting furnace is operated at less than 35% of maximum designed production may be excluded from the 30-day rolling average for purposes of demonstrating compliance with this Section XVI.D.4.d.(i). During each day excluded from the 30-day rolling average, NOx emissions must be measured continuously in accordance with the applicable monitoring requirements of Section XVI.D.5, and the furnace must be operated in accordance with good air pollution control practices.

XVI.D.4.e. Compression ignition RICE

XVI.D.4.e.(i) For a compression ignition RICE with a maximum design power output equal to or greater than 500 horsepower, 9 grams per brake horsepower-hour.

XVI.D.4.e.(ii) Compression ignition RICE subject to the emission limit in Section XVI.D.4.e.(i) above and compression ignition RICE with a maximum design power output less than 500 horsepower must comply with the combustion process adjustment requirements contained in Section XVI.D.6.

XVI.D.5. Compliance demonstration. By October 1, 2021, the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section XVI.D.4. according to the applicable methods contained in this Section XVI.D.5.

XVI.D.5.a. Emissions monitoring requirements for major source RACT limits

XVI.D.5.a.(i) Continuous emission monitoring

XVI.D.5.a.(i)(A) Owners or operators of an affected unit subject to a NOx emission limit in Section XVI.D.4.a.(i)-(ii), c. or d. must install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this section XVI.D.5.a.(i). Owners or operators of affected units subject to a NOx emission limit in Section XVI.D.4.b. or e. may install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section XVI.D.5.a.(i) in lieu of performance testing pursuant to Section XVI.D.5.a.(ii).

XVI.D.5.a.(i)(A)(1) The owner or operator of an affected unit that is subject to or becomes subject to the monitoring requirements of 40 CFR part 75 and 40 CFR part 75, Appendices A to I, must use those monitoring methods and specifications for monitoring NOx emissions for purposes of this Section XVI.D.5. and for demonstrating compliance with Section XVI.D.4. The missing data substitution procedures and bias adjustment requirements of 40 CFR Part 75 do not apply for purposes of demonstrating compliance with Section XVI.D.4. or this Section XVI.D.5.

XVI.D.5.a.(i)(A)(2) For an affected unit equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with an applicable subpart of 40 CFR Part 60, the owner or operator must use the definition of operating day, data averaging methodology, and data validation requirements of the applicable subpart of 40 CFR Part 60 for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section XVI.D.4. The owner or operator must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable requirements of 40 CFR Part 60, Section 60.13, the performance specifications in 40 CFR Part 60, Appendix B, and the quality assurance procedures of 40 CFR Part 60, Appendix F.

XVI.D.5.a.(i)(A)(3) For an affected unit that is not equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with 40 CFR Part 60 or Part 75, the owner or operator must install, operate, and maintain a NOx CEMS or CERMS that measures emissions in terms of the applicable emission limitation and must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable provisions of 40 CFR Part 60, Section 60.13, the performance specifications in 40 CFR Part 60, Appendix B, and the quality assurance procedures of 40 CFR Part 60, Appendix F. The owner or operator must use the following methodology for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section XVI.D.4.:

XVI.D.5.a.(i)(A)(3)(a) A unit operating day is a calendar day when any fuel is combusted in the affected unit.

XVI.D.5.a.(i)(A)(3)(b) 30-day rolling average emission rates must be calculated as the arithmetic average emissions rates determined by the CEMS or CERMS for all hours the affected unit combusted any fuel from the current unit operating day and the prior 29 unit operating days.

XVI.D.5.a.(i)(A)(4) When an affected unit utilizes a common flue gas stack system with one or more affected units, but no non-affected units, the owner or operator must follow the applicable procedures of 40 CFR Part 75, Appendix F for the determination of all sampling locations and apportionment of emissions to an individual affected unit.

XVI.D.5.a.(ii) Initial and periodic performance testing

XVI.D.5.a.(ii)(A) An owner or operator of a stationary combustion turbine subject to 40 CFR Part 60, Subparts GG or KKKK that has used and continues to use performance testing to demonstrate compliance with either Subpart GG or KKKK, as applicable, may use those performance testing procedures to demonstrate continued compliance with an applicable limitation contained in Section XVI.D.4.b., thereby satisfying the requirements of this section XVI.D.5.a.(ii).

XVI.D.5.a.(ii)(B) Except as otherwise provided for in Section XVI.D.5.a.(ii)(A), the owner or operator of an affected unit subject to a NOx emission limitation contained in Section XVI.D.4.b. or e. that is not equipped with NOx CEMS or CERMS, must conduct an initial performance test and subsequent performance tests every 2 years thereafter, according to the following requirements, as applicable, to determine the affected unit's NOx emission rate for each fuel fired in the affected unit. A performance test is not required for a fuel used only for startup or for a fuel constituting less than 2% of the unit's annual heat input, as determined at the end of each calendar year.

XVI.D.5.a.(ii)(B)(1) Initial performance test must include a determination of the capacity load point of the unit's maximum NOx emissions rate based on one 30 minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, and 70 to 100%. Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NOx emissions rate.

XVI.D.5.a.(ii)(B)(2) Performance tests must determine compliance with Section XVI.D.4. based on the average of three 60-minute test runs performed at the capacity load determined in XVI.D.5.a.(ii)(B)(1).

XVI.D.5.a.(ii)(C) All performance tests must be conducted in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

XVI.D.5.a.(iii) For affected units subject to a production-based or output based emission limit contained in Section XVI.D.4. (e.g. lb of NOx/ton of product), the owner or operator must install, operate, and maintain monitoring equipment for measuring and recording the affected unit's production or output, on an hourly basis, in units consistent with the applicable emission limitation.

XVI.D.5.a.(iv) Where measuring fuel use is necessary to calculate an emission rate in the units of the applicable standard, fuel flowmeters must be installed, calibrated, maintained, and operated according to manufacturer's instructions for measuring and recording heat input in terms of the applicable emission limitation. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of 40 CFR Part 75, Appendix D are acceptable for demonstrating compliance with this section. The installation of fuel-flowmeters is not required where emissions of NOx in terms of the applicable standard can be calculated in accordance with applicable provisions of EPA Method 19 or where the standard is concentration based (e.g. parts per million dry volume corrected for oxygen).

XVI.D.6. Combustion process adjustment

XVI.D.6.a. As of January 1, 2017, this Section XVI.D.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx as of June 3, 2016.

XVI.D.6.b. Combustion process adjustment

XVI.D.6.b.(i) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, the owner or operator must conduct the following inspections and adjustments of boilers and process heaters, as applicable:

XVI.D.6.b.(i)(A) Inspect the burner and combustion controls and clean or replace components as necessary.

XVI.D.6.b.(i)(B) Inspect the flame pattern and adjust the burner or combustion controls as necessary to optimize the flame pattern.

XVI.D.6.b.(i)(C) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly.

XVI.D.6.b.(i)(D) Measure the concentration in the effluent stream of carbon monoxide and nitrogen oxide in ppm, by volume, before and after the adjustments in Sections XVI.D.6.b.(i)(A) through (C). Measurements may be taken using a portable analyzer.

XVI.D.6.b.(ii) The owner or operator of a duct burner must inspect duct burner elements, baffles, support structures, and liners and clean, repair, or replace components as necessary.

XVI.D.6.b.(iii) The owner or operator of a stationary combustion turbine must conduct the following inspections and adjustments, as applicable:

XVI.D.6.b.(iii)(A) Inspect turbine inlet systems and align, repair, or replace components as necessary.

XVI.D.6.b.(iii)(B) Inspect the combustion chamber components, combustion liners, transition pieces, and fuel nozzle assemblies and clean, repair, or replace components as necessary.

XVI.D.6.b.(iii)(C) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, confirm proper setting and calibration of the combustion controls.

XVI.D.6.b.(iv) The owner or operator of a stationary internal combustion engine must conduct the following inspections and adjustments, as applicable:

XVI.D.6.b.(iv)(A) Change oil and filters as necessary.

XVI.D.6.b.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary.

XVI.D.6.b.(iv)(C) Inspect spark plugs and replace as necessary.

XVI.D.6.b.(v) The owner or operator must operate and maintain the boiler, duct burner, process heater, stationary combustion turbine, or stationary internal combustion engine consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

XVI.D.6.b.(vi) Frequency

XVI.D.6.b.(vi)(A) The owner or operator must conduct the initial combustion process adjustment by April 1, 2017. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 to satisfy the requirement to conduct an initial combustion process adjustment by April 1, 2017.

XVI.D.6.b.(vi)(B) The owner or operator must conduct subsequent combustion process adjustments at least once every twelve (12) months after the initial combustion adjustment, or on the applicable schedule according to Sections XVI.D.6.c.(i) or XVI.D.6.c.(ii).

XVI.D.6.c. As an alternative to the requirements described in Sections XVI.D.6.b.(i) through XVI.D.6.b.(v):

XVI.D.6.c.(i) The owner or operator may conduct the combustion process adjustment according to the manufacturer recommended procedures and schedule; or

XVI.D.6.c.(ii) The owner or operator of combustion equipment that is subject to and required to conduct a period tune-up or combustion adjustment by the applicable requirements of a New Source Performance Standard in 40 CFR Part 60 or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 may conduct tune-ups or adjustments according to the schedule and procedures of the applicable requirements of 40 CFR Part 60 or 40 CFR Part 63.

XVI.D.7. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request:

XVI.D.7.a. The applicable emission limit and calculated heat input weighted emission limit for stationary combustion equipment demonstrating compliance for multiple fuels.

XVI.D.7.b. The 30-day rolling average emission rate calculated on a daily basis for sources using CERMS to comply with Section XVI.D.

XVI.D.7.c. The type and amount of fuel used.

XVI.D.7.d. The stationary combustion equipment's annual capacity factor on a calendar year basis.

XVI.D.7.e. All records generated to comply with the reporting requirements contained in Section XVI.D.8.

XVI.D.7.f. For stationary combustion equipment subject to the combustion process adjustment requirements in Section XVI.D.6., the following recordkeeping requirements apply:

XVI.D.7.f.(i) The owner or operator must create a record once every calendar year identifying the combustion equipment at the source subject to Section XVI.D. and including for each combustion equipment:

XVI.D.7.f.(i)(A) The date of the adjustment;

XVI.D.7.f.(i)(B) Whether the combustion process adjustment under Sections XVI.D.6.b.(i) through XVI.D.6.b.(v) was followed, and what procedures were performed;

XVI.D.7.f.(i)(C) Whether a combustion process adjustment under Sections XVI.D.6.a. and XVI.D.6.b. was followed, what procedures were performed, and what New Source Performance or National Emission Standard for Hazardous Air Pollutants applied, if any; and

XVI.D.7.f.(i)(D) A description of any corrective action taken.

XVI.D.7.f.(i)(E) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation.

XVI.D.7.f.(i)(F) If multiple fuels are used, the type of fuel burned and heat input provided by each fuel.

XVI.D.7.f.(ii) The owner or operator must retain manufacturer recommended procedures, specifications, and maintenance schedule if utilized under Section XVI.D.6.a. for the life of the equipment.

XVI.D.7.f.(iii) As an alternative to the requirements described in Section XVI.D.7.f.(i), the owner or operator may comply with applicable recordkeeping requirements related to combustion process adjustments conducted according to a New Source Performance Standard in 40 CFR Part 60 or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63.

XVI.D.7.g. All sources qualifying for an exemption under Section XVI.D.2. must maintain all records necessary to demonstrate that an exemption applies.

XVI.D.8. Reporting

XVI.D.8.a. For affected units demonstrating compliance with Section XVI.D.4. using CEMS or CERMS in accordance with Section XVI.D.5.a.(i)(A), the owner or operator must submit to the Division the following information:

XVI.D.8.a.(i) Quarterly or semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual or quarterly period, as applicable. Excess emissions means emissions that exceed the applicable limitations contained in Section XVI.D.4. Excess emission reports must include the information specified in 40 CFR Part 60, Section 60.7(c) (July 1, 2018).

XVI.D.8.b. For affected units demonstrating compliance with Section XVI.D.4 using performance testing pursuant to Section XVI.D.5.a.(ii)(C), the owner or operator must submit to the Division the following information:

XVI.D.8.b.(i) Performance test reports within 60 days after completion of the performance test program. All performance test reports must determine compliance with the applicable emission limitations set by Section XVI.D.4.

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

XVII.A. (State Only) Definitions

XVII.A.1. "Air Pollution Control Equipment," as used in this Section XVII., 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 XVII.B.2.e.

XVII.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.

XVII.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.

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

XVII.A.5. "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.

XVII.A.6. "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.

XVII.A.7. "Date of First Production" means the date reported to the COGCC as the "date of first production."

XVII.A.8. "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.

XVII.A.9. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

XVII.A.10. "Intermediate Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid.

XVII.A.11. "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.

XVII.A.12. "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.

XVII.A.13. "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.

XVII.A.14. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

XVII.A.15. "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.

XVII.A.16. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.17. "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.

XVII.A.18. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

XVII.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.

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

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall 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.

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

XVII.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.

XVII.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:

XVII.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.

XVII.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.

XVII.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 XVII., 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 XVII.

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

XVII.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 XVII.A.5., and may be monitored under the provisions of Section XVII.F.

XVII.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 on that date or thereafter.

XVII.B.3.c. Beginning January 1, 2015, the rod packing on any reciprocating compressor located at a natural gas compressor station must be replaced every 26,000 hours of operation or every thirty six (36) months, unless the reciprocating compressor is subject to 40 CFR Part 60, Subpart OOOO on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

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

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

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

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

XVII.C.1.a. 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 operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. 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 operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.

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

XVII.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.

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

XVII.C.1.b.(i)(C) A storage tank not otherwise subject to Sections XVII.C.1.b.(i)(A) or XVII.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.

XVII.C.1.c. Control requirements within ninety (90) days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, 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 the date of first production. The air pollution control equipment must achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. 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 the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.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 XVII.C.1.b.

XVII.C.1.d. Beginning May 1, 2014, or the applicable compliance date in Section XVII.C.1.b.(i), whichever comes later, owners or operators of storage tanks subject to Section XVII.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 XVII.C.1.e. The additional visual inspections must include, at a minimum:

XVII.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;

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

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

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

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

XVII.C.1.e. 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.

XVII.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.

XVII.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.

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

XVII.C.2. Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section XVII.C.2.b.(ii).

XVII.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:

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

XVII.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).

XVII.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 XVII.C.2.a.

XVII.C.2.b. Owners or operators of storage tanks subject to the control requirements of Sections XII.D.2., XVII.C.1.a, or XVII.C.1.b. 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 XVII.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.

XVII.C.2.b.(i) STEM must include selected control technologies, monitoring practices, operational practices, and/or other strategies; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument monitoring methods following the applicable schedule in Section XVII.C.2.b.(ii) and Inspection Frequency in Table 1.

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

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

XVII.C.2.b.(ii)(B) A storage tank constructed before May 1, 2014, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by May 1, 2015. Approved instrument monitoring method inspections must begin within ninety (90) days of the Phase-In Schedule in Table 1, or within thirty (30) days for storage tanks with uncontrolled actual VOC emissions greater than 50 tons per year.

XVII.C.2.b.(ii)(C) A storage tank not otherwise subject to Sections XVII.C.2.b.(ii)(A) or XVII.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 XVII.C.2.a. and XVII.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of discovery of the emissions increase.

XVII.C.2.b.(ii)(D) Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table 1.

Table 1 – Storage Tank Inspections		
Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Method Inspection Frequency	Phase-In Schedule
≥ 6 and ≤ 12	Annually	January 1, 2016
> 12 and ≤ 50	Quarterly	July 1, 2015
> 50	Monthly	January 1, 2015

XVII.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 XVII.C.1.e.

XVII.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.

XVII.C.3. Recordkeeping: The owner or operator of each storage tank subject to Sections XII.D. or XVII.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:

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

XVII.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance, gauging, or safety of personnel and equipment.

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

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

XVII.C.3.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

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

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

XVII.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 XVII.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.

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

XVII.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

XVII.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.

XVII.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 XVII.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:

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

XVII.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.

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

XVII.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 XVII.D.3. by the date that the glycol natural gas dehydrator commences operation.

XVII.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.

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

XVII.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.

XVII.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.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b., the owner or operator of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in Table 2 shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 2.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 2 as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 2				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.E.3.a.(i)(B) and (C) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(A) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(B) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(C) The requirements of this Section XVII.E.3.a. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

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

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

XVII.F.2. Owners or operators of well production facilities or natural gas compressor stations that monitor components as part of Section XVII.F. 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).

XVII.F.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:

XVII.F.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.

XVII.F.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.

XVII.F.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.

XVII.F.3.d. For purposes of Section XVII.F.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 (tpy)	Inspection Frequency
>0 and ≤ 12	Annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

XVII.F.4. Requirements for well production facilities

XVII.F.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.

XVII.F.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.

XVII.F.4.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).

Table 4 – Well Production Facility Component Inspections				
Thresholds (per XVII.F.4.c.)				
Well production facilities without storage tanks (tpy)	Well production facilities with storage tanks (tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and ≤ 6	> 0 and ≤ 6	One time	Monthly	January 1, 2016
> 6 and ≤ 12	> 6 and ≤ 12	Annually	Monthly	January 1, 2016
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 20	> 50	Monthly		January 1, 2015

XVII.F.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.

XVII.F.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.

XVII.F.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.

XVII.F.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.

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

XVII.F.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.

XVII.F.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.

XVII.F.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.

XVII.F.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.

XVII.F.6.e. 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 XVII.F.7. 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 XVII.F.6., the leak must be repaired and remonitored in accordance with Section XVII.F.7.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. 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.

XVII.F.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.

XVII.F.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.

XVII.F.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.

XVII.F.7.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.

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

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

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

XVII.F.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;

XVII.F.8.c. A list of the leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

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

XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;

XVII.F.8.g. 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;

XVII.F.8.h. The date the leak was remonitored and the results of the remonitoring; and

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

XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted for calendar years prior to January 1, 2018:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.f. 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.

XVII.F.10. Reporting, beginning with the reporting year of 2019: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

XVII.F.10.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

XVII.F.10.b. The total number of inspections performed per inspection frequency tier of well production facilities and inspection frequency tier of natural gas compressor stations;

XVII.F.10.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 XVII.F.10.b., or inspection frequency tier of natural gas compressor stations;

XVII.F.10.d. The total number of leaks repaired for each inspection frequency tier of well production facilities, as reported in Section XVII.F.10.b., or inspection frequency tier of natural gas compressor stations;

XVII.F.10.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 XVII.F.10.b., or inspection frequency tier of natural gas compressor stations, and the basis for each delay of repair;

XVII.F.10.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

XVII.F.10.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.

XVII.G. (State Only) Control of emissions from well production facilities

Well Operation and Maintenance: On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from the date of first production by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and liquids unloading events

XVII.H.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for well venting associated with downhole well maintenance and liquids unloading, unless venting is necessary for safety.

XVII.H.1.a. During liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. The owner or operator must be present on-site during any planned well maintenance or liquids unloading event and must ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under Section XVII.H. must be kept for two (2) years and made available to the Division upon request.

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

XVIII.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).

XVIII.B. Definitions

XVIII.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).

XVIII.B.2. "Continuous Bleed" means an intentional continuous bleed rate of natural gas from a pneumatic controller.

XVIII.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.

XVIII.B.4. "Enhanced Response" means to return equipment to proper operation and includes but is not limited to, cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.5. "High-Bleed Pneumatic Controller" means a 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.

XVIII.B.6. (State Only) "Intermittent pneumatic controller" means a pneumatic controller that vents non-continuously.

XVIII.B.7. "Low-Bleed Pneumatic controller" means a 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.

XVIII.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.

XVIII.B.9. "No-Bleed Pneumatic Controller" means any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.10. "Pneumatic Controller" means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.B.11. "Self-contained Pneumatic Controller" means a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.

XVIII.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:

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

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

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

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.

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

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

XVIII.C.2.a. All pneumatic controllers placed in service on or after January 1, 2018, must have a natural gas bleed rate of zero, unless allowed pursuant to Section XVIII.C.2.c.

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

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

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

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

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

XVIII.C.3.a. Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014, must:

XVIII.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.

XVIII.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 XVIII.C.3.c.

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

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

XVIII.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 XVIII.C.3.c.

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

XVIII.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.

XVIII.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.

XVIII.D. Monitoring

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

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

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

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

XVIII.D.2. In the 8-Hour Ozone Control Area and located at a natural gas processing plant:

XVIII.D.2.a. Effective May 1, 2018, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

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

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

XVIII.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.

XVIII.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.

XVIII.E. Recordkeeping

XVIII.E.1. In the 8-Hour Ozone Control Area:

XVIII.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:

XVIII.E.1.a.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.

XVIII.E.1.a.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour. Owners or operators must use this information to update the estimate required in Section XVIII.E.1.a.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

XVIII.E.1.b. Continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant:

XVIII.E.1.b.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero.

XVIII.E.1.b.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero. Owners or operators must use this information to update the estimate required in Section XVIII.E.1.b.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

XVIII.E.1.c. Records must be maintained for a minimum of five years and made available to the Division upon request.

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

XVIII.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 XVIII.C.1.c. and XVIII.C.2.c. (State Only: and in Section XVIII.C.3.c.). The log shall be updated on a monthly basis.

XVIII.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.

XVIII.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.

XVIII.F. (State Only) Pneumatic Controller Inspection and Enhanced Response in the 8-Hour Ozone Control Area

XVIII.F.1. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

XVIII.F.2. Pneumatic controller inspection

XVIII.F.2.a. Beginning June 30, 2018, 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:

XVIII.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.

XVIII.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.

XVIII.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, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility.

XVIII.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility.

XVIII.F.2.a.(v) For purposes of Section XVIII.F.2.a., 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).

XVIII.F.2.b. Beginning June 30, 2018, 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:

XVIII.F.2.b.(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.

XVIII.F.2.b.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year.

XVIII.F.2.b.(iii) For purposes of Section XVIII.F.2.b., 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.

XVIII.F.2.c. 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.

XVIII.F.2.d. 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.

XVIII.F.3. Enhanced response and remonitoring

XVIII.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.

XVIII.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.

XVIII.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 XVIII.F.2.b., perform any necessary enhanced response in accordance with Section XVIII.F.3., keep records in accordance with Section XVIII.F.4., or submit reports in accordance with Section XVIII.F.5.

XVIII.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.

XVIII.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;

XVIII.F.4.b. A list of pneumatic controllers, including type, determined to be not operating properly;

XVIII.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;

XVIII.F.4.d. The date(s) of enhanced response and a description of the actions taken to return the pneumatic controller to proper operation;

XVIII.F.4.e. The date the owner or operator verified the pneumatic controller was returned to proper operation; and

XVIII.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.

XVIII.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) 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:

XVIII.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);

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

XVIII.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.

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

XIX. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-hour Ozone Control Area

XIX.A. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017:

XIX.A.1. Buckley Air Force (005-0028) – engines (pt 120, 118, 119, 124, 128, 138, 139).

XIX.A.2. Colorado State University (069-0011) – engines (pt 018).

XIX.A.3. DCP Midstream, Greeley (123-0099) – engine (pt 102).

XIX.A.4. DCP Midstream, Kersey/Mewbourn (123-0090) – engine (pt 101).

XIX.A.5. DCP Midstream, Spindle (123-0015) – engines (pt 059, 075).

XIX.A.6. IBM (013-0006) – engines (pt 092, 094).

XIX.A.7. Owens-Brockway (123-4406) – engine (pt 024).

XIX.A.8. Plains End (059-0864) – engine (pt 005).

XIX.A.9. PSCo Cherokee (001-0001) – engine (pt 031).

XIX.A.10. Spindle Hill (123-5468) – engine (pt 005).

XIX.A.11. Suncor (001-0003) – engines (pt 150, 151).

XIX.A.12. Timberline Energy (123-0079) – engines (pt 010, 011).

XIX.B. Elkay Wood Products (001-1602) must comply with applicable requirements in 40 CFR Part 63, Subpart JJ (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

XIX.C. Cemex Construction Materials (013-0003) must comply with applicable THC requirements and associated monitoring, recordkeeping, and reporting in 40 CFR Part 63, Subpart LLL (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

XIX.D. Denver Regional Landfill and Front Range Landfill (123-0079) (pt 007, 013) must comply with applicable flare requirements in 40 CFR Part 60, Subpart WWW (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

XX. Statements of Basis, Specific Statutory Authority and Purpose

XX.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 industries will be able to take advantage of and benefit from this possible shift in product contents.

XX.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.

XX.C. November 21, 1996 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Numbers 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3, Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(I)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulation Numbers 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

XX.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:

Methanol0.16
m-Pyrol0.57

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 emission 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.

XX.E. January 11, 2001 (Sections III.C., IX.L.2.c.(1), and X.D.2. through XI.A.3.)

Readoption of Changes to Regulation Number 7 that were not printed in the regulation or the Colorado Code of Regulations.

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Basis

During a review of the version of Regulation Number 7 adopted by the Air Quality Control Commission and the version of Regulation Number 7 published in the Colorado Code of Regulations, several significant discrepancies have been identified. This rule making will clarify the Commission's intent to adopt the following revisions to Regulation Number 7:

1. Section III.C regarding General Requirements for Storage of Volatile Organic Compounds omits the following revision:

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

2. Section IX.L.2.c.(i) contains discrepancies in reference to the permit number of Coors Brewing Company Emissions Reduction Credit Permit issued on July 25, 1994.

3. Section X.D.2. through Section XI.A.3. was omitted from the CCR as published in the current version of Regulation Number 7.

Authority

Sections 25-7-109, C.R.S. (1997) authorize the Commission to adopt emission control regulations.

Purpose

Re-adoption of the proposed rule will eliminate the discrepancies between the Commission's adopted provisions within Regulation Number 7 and those contained within the Colorado Code of Regulations. Adoption of the amendments will benefit the regulated community by providing sources with consistent information.

XX.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.

XX.G. (March 2004, Sections I.A, I.B., XII., and XVI.

The March 2004 revisions were adopted in conjunction with the Early Action Compact Ozone Action Plan, which is a SIP revision for attainment of the 8-hour ozone standard by December 31, 2007. The Commission adopted four new control measures in Regulation Number 7 to reduce emissions of volatile organic compounds (VOC). The control measures require the installation of air pollution control technology to control: (1) VOC emissions from condensate operation at oil and gas (E&P) facilities; (2) emissions from stationary and portable reciprocating internal combustion engines; (3) certain VOC emissions from gas-processing plants; and, (4) emissions from dehydrators at oil and gas operations.

The new requirements in Sections XII., and XVI. apply to a larger geographic area than the pre-existing requirements of Regulation Number 7, as set out in Section I.A. of the rule. The reference to the "Denver Metro Attainment Maintenance Area", which is not a defined term, in Section I.A was changed to refer to the "Denver 1-hour ozone attainment/maintenance area", which is defined in the Ambient Air Quality Standards Rule. Similarly, the reference to the "Denver Metropolitan Nonattainment Area Ozone Maintenance State Implementation Plan" was changed to the "Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area," which is the correct name of the document submitted to EPA in May 2001.

Regarding VOC emissions from condensate operations, the Commission has determined that an overall reduction of 47.5% VOCs is required of each E&P operation so as to meet the requirements of the SIP. Further the Commission decided not to take a unit-by-unit approach, but rather, the amendments take a more flexible approach to regulating such emissions by requiring sources that have filed, or were required to file, APENs to choose emission controls and locations for applying those controls. This approach also minimizes the risk that sources may reconfigure tanks to avoid implementing the regulation.

Section XII.A.6. provides an exemption for owners and operators with less than 30 tpy of flash emissions subject to APEN reporting requirements. Regulation Number 7 previously included more general exemptions for emissions from condensate operations, but such pre-existing exemptions should have been repealed as part of this revision to Regulation Number 7. To the extent any pre-existing exemption for condensate operations remains, such pre-existing exemption shall not be construed to supersede the requirements of Section XII.

The rule also requires annual reports describing how E&P sources will achieve the requisite emission reductions. Such reports are necessary so that the Division can determine whether or not the emission reductions are being achieved.

Section XII.B. of Regulation Number 7 is required to ensure that existing and new natural gas processing plants employ air pollution control technology to control emissions from leaking equipment, and atmospheric condensate storage tanks (and tank batteries). The Commission is specifically requiring a leak detection and repair (LDAR) program for all gas plants, according to the provisions of 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the affected facility. This is necessary to ensure these large facilities are well controlled and VOC emissions minimized.

Section XII. C. pertains to control of VOC emissions from natural gas dehydration operations. The Commission determined that, in order to meet the requirements of the SIP, emissions must be reduced from all dehydration operations located in the 8-hour Ozone Control Area if such operations produce emissions above the minimum threshold specified in the rule. Further the Commission decided that flexibility should be allowed in how emissions are reduced, so several options are listed from which a source owner or operator may choose. If other equally effective measures or control devices are available, the Division may, on a case-by-case basis, approve the use of such alternatives.

Similarly, Section XVI. establishes controls for reciprocating internal combustion engines. Both "lean" and "rich" burn engines are addressed and though the Commission has specified the default control technology to be applied to each engine type, the Division is allowed to approve alternative technology if a demonstration can be made that the alternative is at least as effective as the listed device in reducing VOC emissions. Parties to the rulemaking hearing provided evidence that suitable, cost-effective control equipment may not be available for some existing engines. The rule adopted by the Commission includes an exemption for lean burn engines if the owner demonstrates that such emissions controls would cost $5,000 or more per ton of VOC removed. In calculating such costs, the Division shall use an appropriate amortization period and current discount rate. The Commission directs the Division to further investigate the question of whether controls are available and suitable for lean burn engines, and to recommend any revisions necessary for the regulation applicable to such engines. New engines locating in the control area must comply with the requirements effective June 1, 2004, but existing engines have until May 1, 2005 to come into compliance. Since the rule provides an exemption for existing engines that cannot be controlled for less than $5,000 per ton, the rule must make the distinction between new and existing engines so that engines will not be moved into the area during prior to May 2005 and subsequently apply for such an exemption.

The Commission recognizes that, at this point in time, the controls required by the rule amendments constitute Reasonably Available Control Technology (RACT), at a minimum, and in some cases, the controls mandated by this regulation may, in fact, constitute Best Available Control Technology (BACT). This means that this regulation shall not be used: (a) to preclude a source from asserting that one of the controls mandated herein constitutes BACT or Lowest Achievable Emissions Rate (LAER) for a new source or major modification, (b) require the Division or Commission to mandate different control technologies as BACT, or (c) preclude the Division or Commission from requiring additional or more stringent air pollution control technologies as necessary or appropriate to comply with applicable BACT or LAER requirements for new sources and major modifications.

By its terms, the New Source Performance Standard (NSPS) applicable to leaking equipment at onshore natural gas processing plants (40 CFR Part 60, Subpart KKK) applies to “affected facilities” and “process units” at such facilities as those terms are defined in the standard. In general, plants that were constructed prior to January 20, 1984 are exempt from the standard, unless subsequently modified or reconstructed, or newly constructed after that date. Since process units at a single gas plant can be distinct, certain gas plants may contain equipment that is not presently subject to the NSPS because of its date of construction. The control requirement in Section XII.B. would extend leak detection and repair program requirements to such equipment.

The statutory authority for the revisions to regulation Number 7 is set out in Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The March 2004 revisions to Regulation Number 7 are based on reasonably available, validated, reviewed, and sound scientific methodologies. All validated, reviewed and sound scientific methodologies and information made available by interested parties has been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution. The Commission chose the most cost-effective mix of control strategies available to comply with the 8-hour ozone NAAQS. Where possible, the regulations provide the regulated community with flexibility to achieve the necessary reductions. The Commission chose the regulatory alternative that will maximize the air quality benefits in the most cost-effective manner.

XX.H. (December 2004, SECTIONS I.A., II.A., XII. and XVI.)

The December 2004 revisions were adopted to respond to U.S. EPA comments on the Ozone Action Plan the Commission adopted in March 2004. EPA required the rule revision in order to make the control measures incorporated into the State Implementation Plan practically enforceable as required by the federal Clean Air Act. The Federal Act requires all of the regulatory provisions adopted in this rulemaking action, and none of the provisions are more stringent than the requirements of the federal act.

The revised rule includes a process for obtaining emission reduction credit for pollution prevention measures. In order to qualify for 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.

XX.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.

Basis

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 more timely 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.

XX.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.

<u>Basis</u>

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.

XX.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.

<u>Basis</u>

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.

<u>Condensate Tank Emissions Control</u>

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 ton per year tanks be considered. In doing this, the Commission intends that tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year or more be considered in determining compliance with the system-wide emissions reductions for the specific ozone non-attainment or attainment maintenance area, and that industry have the flexibility to control smaller tanks in those specific ozone non-attainment or attainment maintenance areas if needed in order to meet the applicable system-wide emissions reductions. For example, if a company owns 20 tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year in a specific ozone non-attainment area, and 15 tanks that emit less than two tons per year, the company would determine its required emission reductions of the production through the 20 two tpy tanks, but be able to control any of the 15 additional less than 2 tpy tanks in order to comply with the system-wide emissions reduction or maintain the desired over control as buffer. However, all tanks controlled in order to comply with the system-wide emissions reduction standard must have filed an APEN and obtained a valid permit in order to be considered as part of the compliance demonstration.

Calendar Weekly and Calendar Monthly Records and Reports

The Commission intends that records and associated reports demonstrating compliance with the weekly emission reduction requirement shall start with the calendar week containing May 1st and end with the calendar week containing September 30th, or other specified dates in the rule. A calendar week begins midnight Sunday morning and ends the following Saturday evening at midnight. Thus, where May 1st falls on any day other than Sunday, the calendar week of May 1st begins on midnight of the preceding Sunday morning. Similarly, the weekly emission reduction requirement applies to the full calendar week that includes September 30th. So, if September 30th falls somewhere in the middle of a calendar week, the emissions reduction requirement applies to that calendar week in full, beginning midnight Sunday morning and ending the following Saturday evening at midnight.

Consequently, calendar monthly records and associated reports demonstrating compliance with the monthly emission reduction requirement shall apply to midnight the morning of day 1 through midnight the evening of the last day of each specific calendar month.

The Commission intentionally broadened the definition of surveillance to provide that: 1) electronic surveillance is not specifically required, and other means to gather information from remote locations is allowed; and 2) data only had to be gathered on a daily basis. The Commission intends that currently required surveillance need only monitor combustion device flame presence or temperature once every day, in order to balance the need to gather adequate data on combustion device operation with the amount of data to be gathered, handled and processed. The Commission believes this is a fair approach considering that only the largest atmospheric condensate storage tanks (those with actual uncontrolled volatile organic compound emissions equal to or greater than 100 tons per year) are subject to this surveillance requirement.

Finally, the Commission intends that the monitoring be completed to ensure compliance, and has determined that failing to monitor as required, losing monitoring data, and failing to maintain monitoring data should be treated similarly to recordkeeping requirements. Thus, these actions “may be treated by the Division as if the data were not collected.”

The Commission intends that system-wide emissions control requirements apply to each specific ozone non-attainment or attainment maintenance area and not collectively to all ozone non-attainment or attainment maintenance areas state-wide. This means that the system-wide emissions control requirements apply specifically to the Ozone Control Area (a.k.a. the Denver Metropolitan Area/North Front Range Ozone Control Area), separately from any future designated ozone non-attainment area. Each new ozone non-attainment area designated in the future shall be subject to the system-wide control requirements by themselves. This is needed to ensure that necessary controls are achieved and maintained in each ozone non-attainment or attainment maintenance area, and that these controls are not removed and offset by system-wide controls in some other ozone non-attainment area.

Pneumatics Emissions Control

This revision establishes new VOC controls for pneumatic controllers in the 8-hour Ozone NAA in Regulation Number 7, Section XVIII. Pneumatic controllers are widely used in the oil and gas industry to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature. Pneumatic controllers of interest are instruments that are actuated using natural gas pressure (of which some natural gas may be bled to the atmosphere from the pneumatic controller and some may be vented from the associated valve). Natural gas-actuated pressure relief devices are not intended to be covered by this rule. There are high-bleed controllers designed to emit more than six standard cubic feet of gas per hour (scfh) to the atmosphere, and low-bleed controllers that emit six scfh or less. Historically, high-bleed controllers have been used.

A 2003 EPA study reported that emissions from pneumatic controllers are collectively one of the largest sources of methane emissions in the natural gas industry. Estimated annual nationwide methane emissions are approximately 31 billion cubic feet (Bcf) from the production sector, 16 Bcf from the processing sector, and 14 Bcf from the transmission sector. As stated, by definition, high-bleed pneumatic controllers emit more than six scfh of natural gas to the atmosphere. The highest bleed rate listed in one source, a table published by the EPA, is 42 cubic feet per hour (cfh). The average bleed rate for high-bleed pneumatic controllers in the NAA is 21 cfh. Natural gas is primarily composed of methane, but also contains other compounds including VOCs and hazardous air pollutants (HAPs). VOC emissions from pneumatic controllers within the NAA were 24.8 tons per day (tpd) for the 2006 baseline and have been projected to be 31.1 tpd for the 2010 baseline. These emissions represent 14.0 and 15.1 percent of the total VOC emissions from oil and gas sources in the NAA in 2006 and 2010, respectively. Therefore, emission reductions related to this source category have the potential to be significant.

These rules require that most high-bleed controllers must be replaced with the equivalent of low-bleed or better pneumatic controllers by May 1, 2009. There is an exception that allows high-bleed controllers that the Division agrees are necessary for safety purposes. Operators must inspect and maintain in-use high-bleed controllers on a monthly basis. Operators must also keep logs of the number of in-use high-bleed controllers, as well as the reasoning that high-bleed controller remains in place, and the inspection and maintenance of the in-use high-bleed controllers. These revisions further require operators to physically tag the in-use high-bleed controllers to enable the Division to track compliance.

The oil and gas industry has already begun replacing high-bleed controllers with low-bleed controllers, understanding the financial gain of minimizing the bleed rate of pneumatic controllers.

RICE Controls

Reciprocating internal combustion engine (RICE) requirements of Regulation Number 7, Section XVI. applies in what was the early action compact area (now the Ozone NAA). These revisions extend the RICE requirements' applicability to a state-wide basis.

Expand and Clarify RACT Requirements

Regulation Number 7 is revised to expand its application to all subject sources in any Ozone NAA and Attainment/Maintenance Areas. This previously applied to the one-hour attainment/maintenance area nonattainment area. Accordingly, this regulation will apply to some sources that were previously outside of its geographic scope. It is intended that existing sources become subject to previously adopted Control Technique Guidelines (CTGS) or general RACT requirements, and are given time to comply to implement the general RACT requirements. Specifically, existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements. All new or modified sources become subject to these general RACT requirements upon commencing operation after the new ozone non-attainment designation date. This revision is considered a measured approach to ensuring the consistent use of best practices across the NAA as well as reductions in ozone precursors considered necessary to attaining the 8-hour ozone standard.

This revision expands Regulation Number 7's applicability to any Ozone NAA or attainment/maintenance area. This is done intentionally to apply Regulation Number 7 requirements to current as well as any future Ozone NAA or attainment maintenance areas in Colorado.

Additionally, this revision clarifies how the Regulation Number 3 RACT requirements interact with Regulation Number 7. This revision specifies that pursuant to Regulation Number 7, Section II.C. all existing sources that emit 100 tons per year of VOC emissions and that are located in the 8-hour Ozone NAA become subject to RACT.

Further, Regulation Number 7 is currently unclear on whether or not existing sources that are modified become subject to new source requirements. This revision clarifies that existing sources that are modified are subject to the Regulation Number 3, Part B, Section II.D. requirements and are considered to be a new source for the purposes of Regulation Number 7.

This revision also clarifies that the both case-by-case and general RACT requirements of Regulation Number 7, Section II.C. only apply to existing, new and modified sources. For sources at which all air pollution generating activities at that source are already subject to RACT or BACT, the RACT analysis would show that all activities are already subject to RACT or BACT. For any other air pollution generating activities not covered by RACT or BACT, the source would only have to complete a RACT analysis specific to those activities.

Typographical, Grammatical, Formatting and Other Changes

The commission changed the title of Regulation Number 7 to include NOx. An outline of the sections is provided to better understand the contents of Regulation Number 7. Outdated sections are removed (i.e. Section II.F.1. specific to Gates Rubber Company, which is now out of business). Section XII., specific to condensate tanks in the Ozone NAA is reorganized for clarity. One appendix (new Appendix A) is added to provide maps of Ozone NAAs and chronologies of attainment designations, of which certain requirements key off. Finally, sections and appendices are renumbered and formatted as necessary.

Section 110.5 and 110.8 Analysis

Some of these revisions are not intended to be incorporated into Colorado's SIP. To the extent these revisions could be construed to exceed the requirements of federal law, the Commission provides the following additional statement, consistent with C.R.S. § 25-7-110.5(5)(a):

(I) These rules are intended to reduce uncontrolled emissions of ozone precursor pollutants. The rules thereby serve to attain and maintain compliance with the National Ambient Air Quality Standard (NAAQS) for Ozone. However, there are no comparable federal requirements that apply to the sources in question.

(II) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. There is considerable flexibility in meeting the NAAQS. However, there are very limited sources of uncontrolled anthropogenic ozone precursor emissions to target in order to reduce ozone. Consequently, the sources in question, as a significant source of uncontrolled VOCs and NOx, must be targeted in order to attain the standard.

(III) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. The ozone NAAQS was not determined taking into account concerns that are unique to Colorado.

(IV) These rules may prevent or reduce the need for costly retrofit to meet more stringent requirements at a later date. The DMA/NFR non-attainment area has violated the 0.08 ppm ozone NAAQS. Colorado will soon be required to comply with the new ozone NAAQS of 0.075 ppm. Colorado Governor Ritter has directed that Colorado air quality planning agencies implement measures to reduce ozone to a level below the NAAQS. If these rules are not adopted now, it may be necessary to require more costly 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.

XX.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.

XX.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. 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 ton 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.

XX.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 below.

"Approved instrument monitoring method" ("AIMM") means the methods and technologies utilized for monitoring storage tanks and components at well production facilities and natural gas compressor stations. The instrument being used for AIMM inspections must be capable of measuring hydrocarbon compounds at the applicable leak definition concentration specified in the revisions, and calibrated as appropriate. See EPA Method 21 at 6.0. In addition, while the definition lists EPA Method 21 and IR cameras, the Commission does not intend to limit industry to only EPA Method 21 and IR cameras as the Division may approve the use of additional monitoring devices and methods.

"Component" excludes compressor seals and open-ended valves and lines, which are defined separately, because they are designed to leak and are better addressed with equipment specific work practices, also included separately. Based on concerns that the requirements for small reciprocating compressors at well production facilities may not be cost-effective, the adopted work practices for reciprocating compressors are limited to reciprocating compressors located at natural gas compressor stations. Nevertheless, there is an issue as to whether compressors at well production facilities are a significant source of emissions. The Commission, therefore, directs the Division to investigate whether reciprocating compressors at well production facilities are a significant source of emissions, and if so, whether there may be appropriate, cost-effective work practices to reduce fugitive emissions from reciprocating compressors at well production facilities. The Commission further directs the Division to brief the Commission on this investigation in March, 2015.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both COGCC and Commission requirements.

"Natural gas compressor stations" are subject to leak detection and repair requirements. This definition is meant to exclude compressors at well production facilities and gas processing plants. This definition is also meant to exclude natural gas compressor stations that are downstream of the natural gas processing plant at this time.

"Normal operation" is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of "malfunction" as set forth in the Common Provision regulations.

"Storage tank," means a single storage tank or a storage tank battery if the storage tanks are manifolded together. In recent years, it has become more common for multiple storage tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of "storage tank," the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery. The Commission's definition, and Colorado's approach to emissions reporting and permitting for storage tanks, differs from EPA's definition of "storage vessel" and the description of an affected storage vessel facility in NSPS OOOO because EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. The Commission intends to maintain this distinction and, therefore, deletes the previously used definition of "atmospheric condensate storage tank" and creates a new definition of "storage tank" which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

"Well production facilities" are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The "owned, operated, or leased" qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from "well production facility" and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells.

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas operations, including those below control thresholds or even below Regulation Number 3 APEN and permitting thresholds, adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;
- Inspecting and repairing seals on thief hatches, access points, or other openings of storage tanks;
- Initiating timely action to address leaks or unpermitted emissions; and
- Maintaining equipment and the facility in good operating condition.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. The Commission intends these revisions to address venting emissions from storage tank thief hatches, pressure relief valves, or other access points during normal operations. Access points are not limited to points of entry of liquids or gas into the storage tank but include any route from which emissions can escape. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices and that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. The Commission does not intend to increase risk or compromise safety of personnel and equipment. However, inadequate design of a storage tank emissions capture system is not a legitimate reason for venting.

Therefore, the Commission intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to owners or operators, provided that the owners or operators demonstrate that the elements of the malfunction defense have been met. The Commission intends that the burden remain on the owner or operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2. The Commission further recognizes that meeting the no venting requirement may be challenging in some cases, and accordingly has adopted additional provisions requiring owners and operators to develop a STEM plan to help ensure compliance. In some cases, development and implementation of the STEM plan may be an iterative process involving ongoing improvements before continuous compliance with the no venting standard is achieved. With this in the mind, the Division should consider the efforts of owners and operators in developing and implementing their STEM plan as part of the Division's assessment about how best to enforce the no venting requirement.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and natural gas compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered by the owner or operator or the Division inspector pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if a leak is identified and the owner or operator is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the owner or operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners or operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tanks Controls (Section XVII.C.)

EPA established a six (6) tpy VOC threshold on a controlled actual emissions basis for applying storage vessel controls. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for applying reporting, permitting, and control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control equipment may be removed if: (1) the storage tank (including manifolded tanks) emissions fall below the uncontrolled actual six (6) tpy threshold, on a rolling twelve month basis; and (2) those controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the uncontrolled actual six (6) tpy threshold on a rolling twelve month basis, air pollution control equipment must be installed within sixty (60) days of discovery of the increase.

The Commission does not intend for the storage tank control, or related, requirements to apply to frac tanks that are located at a well production facility for less than 180 consecutive days.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used the device must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Audio, Visual, Olfactory ("AVO") and Visual Inspections (Section XVII.C.)

The Commission intends that owners and operators of subject storage tanks (including storage tanks during the first ninety (90) days of production and storage tanks containing only stabilized liquids) conduct applicable AVO and visual inspections for venting or leaking. Visual inspections are in addition to AVO monitoring and require further inspections of the storage tank and associated equipment, such as thief hatches and air pollution control equipment. These inspections are not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO and visual inspection, and indicates the frequency at which inspection is required.

Storage Tank Emission Management System ("STEM") Plan, Monitoring, and Recordkeeping (Section XVII.C.)

Owners and operators of storage tanks with uncontrolled actual emissions equal to or greater than six (6) tpy must develop, certify, and implement a STEM plan designed to ensure compliance with the "without venting" requirement of Section XVII.C.2., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies, monitoring, maintenance, and operational practices to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility to develop STEM plans on an individual basis for each storage tank or for multiple storage tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review. Owners and operators of storage tanks controlled during the first ninety (90) days of production or containing only stabilized liquids are not required to develop and implement a STEM plan. However, owners or operators of such storage tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include, but is not limited to, the following elements:

- A monitoring strategy including, at a minimum, the applicable inspection frequencies and methodologies;
- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the owner or operator to demonstrate the quality and achievements of the STEM plan;
- The calibration methodology and schedule for emission detection equipment used in the monitoring;
- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;
- A procedure to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and
- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

In addition to AVO and visual inspections for storage tanks, STEM plans must include AIMM inspections on a frequency schedule that is tied to the uncontrolled actual VOC emissions from the storage tank. The Commission intends that the AIMM inspection satisfy any simultaneous AVO and visual inspection requirement.

The STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of applicable monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Unsafe, Difficult, or Inaccessible to Monitor (Sections XVII.C. and XVII.F.)

The Commission does not intend to require owners or operators to conduct either AVO or AIMM inspections of unsafe, difficult, or inaccessible components or storage tanks and associated equipment. The Commission acknowledges that, in limited circumstances, unsafe to monitor may include unsafe weather or travel conditions. However, in those limited circumstances, the Commission expects the owner or operator to resume monitoring once the weather or travel conditions cease to be unsafe. Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season.

Glycol Natural Gas Dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. This revision requires that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of six (6) tpy or greater be controlled with air pollution control equipment achieving at least a 95% reduction. This revision also requires that existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled if the dehydrator is located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations. The Commission does not intend to apply this proximity requirement to the glycol natural gas dehydrator owner or operator's buildings, where public access to the building is also restricted. Further, because glycol natural gas dehydrators are different and unique sources, a similar proximity requirement for storage tanks is not appropriate at this time as storage tanks are more appropriately addressed based on emission thresholds.This revision also requires that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. The leak detection and repair program more broadly targets leaks from components at natural gas compressor stations and well production facilities, even if such facilities do not include storage tanks. In contrast, STEM targets venting from storage tanks. The use of an AIMM as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may have lower emissions and may need additional time to comply. Owners or operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor. Owners or operators also have flexibility in timing the AVO and AIMM inspections to coordinate overlapping AVO and AIMM inspections, as well as inspections of facilities in the same area or on the same inspection frequency. The Commission intends that the AIMM inspection satisfy any simultaneous AVO inspection requirement. However, the Commission expects that owners and operators will also utilize this flexibility to ensure that inspections are appropriately spaced on the frequency schedule (e.g. quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Commission distinguished between new and existing well production facilities by utilizing an October 1, 2014, commenced construction date and created an inspection phase-in schedule for existing facilities.

The Commission also distinguished the emissions thresholds for determining inspection frequencies for well production facilities with storage tanks and well production facilities without storage tanks. For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on "facility emissions." The Commission has determined that "facility emissions" means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.

The Commission has defined a leak requiring repair in a manner that is dependent on the monitoring methodology. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identify the emission rate. Similarly, while IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in selecting a leak detection methodology.

If EPA Method 21 is utilized, the Commission set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing natural gas compressor stations and 500 ppm for new (constructed after May 1, 2014) natural gas compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is utilized, a leak is any detectable emission not associated with normal equipment operation (e.g. the acceptable level of leaks from a component designed to leak). These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources. Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO identifies leaks at natural gas processing plants at 500 ppm. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices. Further, the Commission finds that the repair deadlines set forth in Section XVII.F.7. provide flexibility for operational differences, including the potential range of leaks and degrees of repair difficulty that may be encountered.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country.

The Commission expects that owners and operators will remonitor leaks requiring repair with either the approved instrument monitoring method the owner or operator used to identify the leak or any method approved for remonitoring of leaks under EPA Method 21.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in permits existing as of the promulgation date of the revisions. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and owners and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

During the rulemaking, several parties requested more stringent requirements for all oil and gas operations located within 1,320 feet of a building unit or designated outside activity area. Residents living within close proximity to oil and gas operations, particularly those living within 1,320 feet of oil and gas operations, may understandably have heightened concerns regarding potential impacts of emissions from such facilities. It is the Commission's understanding that some oil and gas owners and operators implement practices beyond what is currently required under state law in order to minimize emissions and otherwise be good neighbors, including conducting increased site inspections. The Commission supports such practices.

Also during the rulemaking, various parties provided extensive evidence concerning the frequency of instrument monitoring method inspections, the timing of leak repair, and the costs and benefits associated with more or less frequent monitoring and repair. The Commission recognizes that additional information would benefit the Commission, Division, industry, and other stakeholders and therefore encourages the Division to work with energy companies, to evaluate the comparative effectiveness of various kinds of instrument based monitoring methods and program designs at a range of types, sizes, and frequencies at well production facilities and natural gas compressor stations.

The Commission also encourages the Division to work with industry and other stakeholders to evaluate emissions from and potential control strategies for downstream natural gas compressor stations and intermittent pneumatic controllers.

Lastly, several parties to the rulemaking requested greater transparency and public access to air quality information associated with oil and gas development. In particular, a coalition of local community organizations requested that owner and operators' annual reports as required by these rules be posted on the Division's website. The Commission believes these reports will provide important information when reviewing the efficacy of the inspection and maintenance program, as well as valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make this information available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. In addition, the Commission requests an annual briefing on these regulations. Such briefing will assist the Commission and interested stakeholders to understand the data and implementation issues relating to this new program, as well as other initiatives covered in this rulemaking. The Commission believes that this information would also be valuable to all parties.

Well Maintenance and Liquids Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well maintenance and well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading emissions are estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008, rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. However, the Commission does not intend to expand the pneumatic device requirements to intermittent pneumatic controllers at this time. Further, while the use of low-bleed pneumatic controllers will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources. However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is only requiring the use of no-bleed pneumatic controllers at facilities that are connected to the electric grid, using electricity to power equipment, and where technically and economically feasible.

<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 more costly 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.

XX.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.

Ozone reclassification SIP revisions

8-hour ozone control area

All provisions of Regulation Number 7 currently apply to the Denver 1-hour ozone nonattainment and attainment/maintenance area. The 1-hour ozone area does not include all of Adams and Arapahoe counties or the portions of Larimer and Weld counties included in the 8-hour ozone control hour. Therefore, to ensure that all sources in the 8-hour ozone nonattainment area are subject to applicable RACT requirements in Regulation Number 7 on a federally enforceable basis, the Commission revised Regulation Number 7, Section I.A.1.a. to state that all provisions apply to both the 1-hour and 8-hour ozone areas. The Commission intends that provisions clearly marked "state-only" continue to be enforceable only on a state-only basis, and are not included in the SIP.

Auto-igniter and storage tank AVO

Regulation Number 7, Section XII.C.1.e. includes auto-igniter requirements for combustion devices used to control emissions of VOCs. Pursuant to Section XII.E., the auto-igniter must be inspected weekly to ensure it is properly functioning. Prior to the revision, these requirements were "state-only". The Commission revised these provisions to include the auto-igniter installation, operation, and monitoring requirements in the SIP.

Regulation Number 7, Section XII.E. includes requirements for owners or operators of condensate storage tanks subject to Section XII.D. to inspect combustion devices, vapor recovery units, control devices, and thief hatches. These are SIP requirements. Regulation Number 7, Section XVII.C.1.d. also requires of owners or operators of storage tanks subject to Section XVII. to conduct AVO and additional visual inspection at the same frequency as liquids load-out. The requirements of Section XVI.C.1.d. are enforceable on a "state-only" basis. The Commission revised Section XII. to include in the SIP the requirement that owners and operators conduct AVO inspections of condensate storage tanks with uncontrolled actual VOC emissions of 6 tons per year ("tpy") or greater, making them federally enforceable.

Lithographic and letterpress printing RACT

Pursuant to CAA Section 182(b), Colorado's ozone SIP must provide for implementation of RACT at sources of VOC for which EPA has issued a Control Technique Guideline ("CTG"). EPA's Offset Lithographic Printing and Letterpress Printing CTG ("Printing CTG") addresses VOC emissions from the use of fountain solutions, cleaning materials, and inks at lithographic and letterpress printing operations. The Printing CTG recommends controlling VOC emissions from heatset printing with dryer emissions of at least 25 tpy of VOC from heatset inks with add-on control technology. The Printing CTG recommends controlling VOC emissions from cleaning materials and fountain solutions at printing operations with facility emissions equal to or greater than 15 lb/day by limiting the VOC content of cleaning materials and fountain solutions. The Printing CTG also recommends work practices for printing operations with facility emissions equal to or greater than 15 lb/day.

Colorado has sources in the ozone nonattainment area in this CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included these requirements in Section XIII.B. as RACT for these sources. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy. This is roughly equivalent to the 15lbs/day threshold recommended in the Printing CTG. Based on the Printing CTG, the Commission added language to Section XIII.B.1.b. clarifying that fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses are considered part of the printing process and are not subject to the surface coating or industrial cleaning solvent requirements in Regulation Number 7. With respect to the compliance threshold for Section XIII.B., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. Only emissions from the printing operation and cleaning thereof should be considered in determining if emissions exceed 3 tpy.

The Commission included additional work practices, a VOC content limit for inks and monitoring, recordkeeping and performance testing requirements that are not specified in the Printing CTG but are intended to correspond to current permit requirements and ensure the enforceability of the requirements. With respect to the work practice requirements contained in Section XIII.B.1.c., the Commission applied these requirements to all lithographic and letterpress printing operations, regardless of potential or actual VOC emissions, because they are minimally burdensome, good housekeeping requirements that reduce emissions and correspond to current permit requirements. With respect to the VOC content limit for inks, the Commission included a 40% limit for heatset web offset and heatset web letterpress printing operations that require higher VOC content ink, and a 30% limit for all other lithographic and letterpress printing operations that are commonly already using low VOC inks. Compliance with the VOC content requirement for inks is demonstrated using a weighted average which takes into account the amount of the different inks used and their respective VOC contents.

For consistency with the Printing CTG, cleaning solutions are subject to VOC content or vapor pressure requirements, except that sources using less than 110 gallons of non-compliant cleaning materials per calendar year are exempt from the VOC content or vapor pressure requirements. Larger heatset printing operations, whose maximum allowable emissions before controls from petroleum inks are 25 tpy VOC or more, are subject to a control requirement (not capture and control). Printing operations' emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Industrial cleaning solvents RACT

EPA's CTG for Industrial Cleaning Solvent ("Cleaning Solvent CTG") addresses solvent use in cleaning operations such as spray gun cleaning, spray booth cleaning, large manufactured components cleaning, parts cleaning, equipment cleaning, line cleaning, floor cleaning, tank cleaning, and small manufactured components cleaning. The Cleaning Solvent CTG applies to facilities with VOC emissions from the use of industrial cleaning solvents equal to or greater than 15 lb/day of VOC. The Cleaning Solvent CTG recommends a cleaning solvent VOC content limit and work practices.

Colorado has sources in the ozone nonattainment area in this Cleaning Solvent CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included requirements in Section X.E. as RACT. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy on a calendar basis. This is roughly equivalent to the 15lbs/day threshold recommended in the CTG. The Commission intended for the term "industrial cleaning solvent operation" to be broad and apply to a wide range of work areas where manufacturing or repair activities are performed, but not to residential or janitorial cleaning.

The Commission included language to clarify that VOC emissions that are exempt from the industrial cleaning solvent rule do not count toward this 3 tpy threshold. Therefore, when determining whether a facility meets the applicability threshold of 3 tpy, a source should include facility-wide emissions from all industrial cleaning solvent operations and subtract those emissions that are exempt under Section X.E.4. In adopting the VOC content limit in Section X.E.1.a. and the vapor pressure limit in Section X.E.1.b., the Commission intended for these to be straight, as-applied limits for all industrial cleaning solvents used and not a weighted average. Additionally, in adopting the 90% control efficiency compliance option in Section X.E.1.c., the Commission did not intend for this control efficiency to include capture efficiency. The Commission acknowledged that capture efficiency may be lower than the control efficiency because industrial cleaning solvents are often used over large industrial complexes and result in relatively small VOC emissions.

With respect to the compliance threshold for Section X., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. The Commission also included monitoring, recordkeeping and reporting requirements that are not specified in the Cleaning Solvent CTG but are intended to align with current permit recordkeeping requirements and ensure the enforceability of the requirements.

The Commission included language in Section X.E.4.a.(ii) providing that industrial cleaning solvent operations subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT are exempt from the requirements of Section X. This provision was included so as not to subject sources to overlapping, duplicative, or contradictory RACT requirements. Therefore, if an industrial cleaning solvent operation is subject to a work practice or emission control requirement contained in another, federally approved section of Regulation Number 7, including but not limited to Sections IX. (surface coating operations), X.B. through X.D. (solvent cold-cleaners, non-conveyorized degreasers, and conveyorized degreasers), and XIII. (graphic arts and printing), then that operation would not also be subject to the requirements of Section X.E.4. However, this provision is not intended to exempt an industrial cleaning solvent operation from Section X. when the operation is subject to the restriction on disposal of VOCs by evaporation or spillage contained in to Section V.A. (and RACT is determined to be nothing). Therefore, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be nothing, the operator must comply with Section X. Conversely, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be a work practice or emission control requirement, then the operation is exempt from Section X. Lastly, the Commission adopted additional exemptions recommended in the Cleaning Solvent CTG in Section X.E.4.b. as well as an alternative compliance option for area source aerospace facilities in Section X.E.4.c. due to the unique solvent cleaning needs of those source categories.

Control requirements do not account for capture and control. General industrial solvent use emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Major VOC and NOx source RACT

Colorado has major sources of VOC or NOx (sources that emit or have the potential to emit greater than 100 tpy) in the DMNFR. While many of these sources are currently subject to regulatory RACT requirements in Colorado's SIP, some of the sources or emissions points are subject to RACT requirements in federally enforceable permits or New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado is submitting a SIP revision to include provisions requiring the implementation of RACT for major sources of NOx or VOC in the DMNFR. Therefore, the Commission included a work practice for combustion equipment at major sources of NOx emissions in Section XVI., a requirement for specific major sources to provide RACT analyses to the Division in Section XIX.B., and incorporated by reference applicable requirements of a NSPS or NESHAP in Sections XIX.C-G.

Specifically, the Commission adopted a combustion process adjustment requirement for individual pieces of combustion equipment at major sources of NOx in Section XVI.D., expanding on work practices currently required in federal NESHAP. The combustion process adjustment was modeled after NESHAP DDDDD, which applies to boilers and process heaters at major HAP sources, and NESHAP ZZZZ, which establishes various requirements for stationary reciprocating internal combustion engines. Section XVI.D. is intended to apply to some equipment that is not subject to work practices under the NESHAPs (e.g., natural gas fired boilers at area sources of HAPs) that have uncontrolled actual NOx emissions (annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice without consideration of any emission control equipment or procedures) equal to or greater than 5 tpy. The Commission intended major NOx sources to use the most recent APEN submitted to the Division as of January 1, 2017, to determine whether the combustion equipment is subject to the requirement to conduct an initial combustion process adjustment by April 1, 2017, or alternatively document reliance on an allowed, alternative adjustment. Subsequent determinations will be based on the most recent APEN submitted to the Division as of the year the combustion equipment may be subject to the combustion process adjustment requirements (e.g., most recent APEN submitted to the Division as of January 1, 2018, to determine whether a combustion process adjustment is required in 2018). In addition to the specific adjustment requirements, the Commission intended owners and operators to operate and maintain subject equipment consistent with manufacturer specifications or best combustion engineering practices.

The Commission also established RACT requirements for emission points at major sources of VOC or NOx in the DMNFR area in Section XIX. In Section XIX.A., the Commission listed all major sources of VOC or NOx at the time of adoption of the Moderate nonattainment area RACT SIP. The Commission determined that not all emission points above permitting thresholds at major sources were necessarily subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP. Therefore, in Sections XIX.C. through XIX.G., the Commission incorporated federal NSPS or NESHAP requirements, including monitoring, recordkeeping, and reporting requirements, for some sources to further satisfy Colorado's RACT obligation for Colorado's major VOC and NOx sources. The Commission acknowledges concerns over potential EPA revisions to NSPS and NESHAP incorporated by reference in Sections XIX.C.through XIX.G., and intended that sources comply with applicable requirements in the most up-to-date version of the federal rule, or alternative requirements approved by EPA in accordance with the NSPS or NESHAP. The Commission also directs the Division to initiate efforts to update the incorporation by reference in the SIP, as necessary and with all due diligence. Sources identified in Section XIX.A. but not specifically included in Sections XIX.B. through XIX.G., were determined to be subject to other, existing regulatory RACT requirements in Colorado's SIP (see the Moderate ozone SIP revision, RACT Chapter 6 and the Technical Support Document for Reasonably Available Control Technology for Major Sources for additional detail). Concerning major sources or source emission points not subject to other, existing regulatory RACT requirements in Colorado's SIP or specified in Sections XIX.C. through XIX.G., the Commission required owners or operators to submit RACT analyses for the facility or specific emission points to the Division by December 31, 2017. The RACT analyses should identify potential options to reduce NOx and/or VOC emissions from the facility or emission point(s), propose RACT for that facility or point, propose associated monitoring, propose a schedule for implementation, and include economic and technical information showing why the RACT proposal is RACT for the particular facility or point. These RACT analyses are not to be limited by a January 1, 2017, implementation date.

CoorsTek submitted a permit application to limit permitted emissions of VOC below 100 tpy. Metro Wastewater Reclamation District submitted an application for minor modification to its Title V permit to correct inconsistencies and remove obsolete limits, which lowered the combined Metro Wastewater/Suez Denver Metro permitted NOx emission limit below 100 tpy. Consequently, the Commission determined that the facilities no longer met the definition of a major source, and therefore were not included in Section XIX. Should either source fail to obtain such federally enforceable permits by July 1, 2018, the Commission directs the Division, with all due diligence, to initiate efforts to establish RACT requirements for that source in Colorado's ozone SIP.

Current SIP review

In 2009, the Commission submitted revisions to Regulation Number 7, Section XII. to EPA related to the 1997 ozone NAAQS attainment plan. In 2011, EPA approved the attainment demonstration but disapproved portions of the Regulation Number 7 revisions. In 2013, the Commission submitted revisions to Regulation 7, Section XII. to EPA to address EPA's disapproval. During the review of the 2013 submittal, EPA noted additional concerns with the monitoring, recordkeeping, and reporting requirements for natural gas processing plants and glycol natural gas dehydrators, as well as other concerns unrelated to the attainment demonstration for the SIP revision required following the reclassification of the DMNFR area to Moderate.

Natural gas processing plants

Regulation Number 7, Section XII.G.1. identifies a leak detection and repair ("LDAR") program applicable to natural gas processing plants. This "LDAR program" includes all applicable requirements in NSPS KKK. EPA has promulgated new LDAR programs for natural gas processing plants in NSPS OOOO and NSPS OOOOa. Therefore, the Commission updated references to applicable federal NSPS (i.e., NSPS OOOO and NSPS OOOOa) monitoring, recordkeeping, and reporting requirements for natural gas processing plants in the SIP.

Glycol natural gas dehydrators

Regulation Number 7, Section XII.H. already includes a 90% control requirement for glycol natural gas dehydrators. This is a SIP requirement. During the review of the 2013 submittal, EPA noted practical enforceability concerns with the monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators. Therefore, the Commission added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in the SIP to address EPA's concerns with ensuring compliance with the control requirement. The Commission based these requirements off of the Division's glycol natural gas dehydrator Operation and Maintenance Plan template to align the Section XII.H. monitoring, recordkeeping, and reporting requirements with the Operation and Maintenance Plan template, where possible. For any glycol dehydration system monitoring, recordkeeping and reporting requirement adopted for inclusion in the SIP during this hearing that conflicts with a similar provision in a Division approved Operation and Maintenance Plan, the Commission intends that sources only have to comply with the provision adopted for inclusion in the SIP and not the competing requirement in the approved Operation and Maintenance Plan. Further, the Commission directs the Division to work with industry to revise the Division's glycol dehydration systems Operating and Maintenance Plan template to remove requirements that are duplicative of the Section XII.H. monitoring, recordkeeping, and reporting requirements, to alleviate competing requirements with Section XII.H., as necessary.

EPA requested revisions

EPA also noted concerns with other previously submitted provisions in Section XII. EPA requested minor changes to Section XII.C.1.c., and a reversion to previously approved SIP language in Sections XII.C.1.d. and XIII.E.3.a. to address concerns with discretionary language. In response, the Commission revised Section XII.C.1.c. and reverted to previously approved SIP language in Sections XII.C.1.d. and XII.E.3.a., as requested by EPA.

Incorporation By Reference in Section XIX

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Section XIX.C through H by reference.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. The Commission also adopted revisions to Regulation Number 7 to address EPA concerns that are unrelated to the reclassification to Moderate. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address combustion device auto-igniters, condensate storage tank inspections, and glycol natural gas dehydrators at oil and gas facilities and equipment leaks at natural gas processing plants. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks and glycol natural gas dehydrators. For example, Regulation Number 7 addresses more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to tri ethylene glycol ("TEG") dehydrators. The Commission revised Regulation Number 7 to include glycol natural gas dehydrator monitoring, recordkeeping, and reporting requirements to ensure compliance with the current 90% system-wide control requirement in Section XII.D. Similarly, Regulation Number 7 addresses more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. Regulation Number 7 also addresses a broader set of storage tanks than NSPS OOOO and NSPS OOOOa, which address only those storage tanks with emissions greater than 6 tpy controlled actual emissions (i.e., 120 tpy uncontrolled actual emissions) and do not require auto-igniters on combustion devices. The Commission revised Regulation Number 7 to include the auto-igniter and condensate storage tank AVO inspections in Colorado's SIP to strengthen Colorado's SIP and support Colorado's 2017 emissions inventory. In addition, Regulation Number 7 addresses more equipment leaks at natural gas processing plants than NSPS KKK, which only applies to natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. The Commission revised Regulation Number 7 to reference the more recent equipment leak detection and repair requirements in NSPS OOOO and NSPS OOOOa.

The revisions to Regulation Number 7 also address RACT requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of VOC and NOx in Colorado's ozone nonattainment area. EPA published CTGs for lithographic and letterpress printing and industrial cleaning solvents in 2006. The Commission revised Regulation Number 7 to include regulatory RACT requirements for these VOC source categories. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission revised Regulation Number 7, Sections XVI. and XIX. to include source specific regulatory RACT requirements and a combustion process adjustment for combustion equipment at major sources of NOx. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with a lower ozone NAAQS in the near future. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Section XII. strengthen Colorado's SIP, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7 Sections X. and XIII. recognize products and practices currently utilized by printing and industrial cleaning solvent operations. The revisions to Regulation Number 7 Sections XVI. and XIX. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Section XII. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7 Sections X., XIII., and XVI. similarly establish the categorical RACT requirements for similarly situated and sized sources. Where a source is not subject to a categorical RACT requirement, RACT is, by its nature, determined on a case-by-case basis.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for auto-igniters, condensate storage tank inspections, and equipment leaks at natural gas processing plants. Other revisions reflect changes in industry practice and market forces, such as the VOC content of printing materials and cleaning solvents. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate Nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

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

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

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

XX.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 above, Colorado must adopt RACT into its Ozone SIP for sources covered by the Oil and Gas CTG. While the Oil and Gas CTG recommends presumptive RACT, it does allow states the flexibility to determine what constitutes RACT for the state's covered sources. Further, while EPA's Oil and Gas CTG implementation memorandum provides guidance that the emission controls determined by the state to be RACT for the sources covered by the Oil and Gas CTG must be implemented as soon as practicable but in no case later than January 1, 2021, states also have the flexibility to determine the appropriate implementation timeframe for the sources within the state's ozone nonattainment area. The Commission determined that some of Colorado's existing regulations (*i.e.,* the "system-wide" control program for condensate tanks in Section XII.D.2.) achieve greater emission reductions than the RACT recommended by the Oil and Gas CTG. The Commission determined that some sources covered by the Oil and Gas CTG were not addressed in existing regulations (*i.e.,* pneumatic pumps). The Commission also determined that some sources addressed in the Oil and Gas CTG (*i.e.,* components at well production facilities and natural gas compressor stations, compressors, pneumatic controllers) are already subject to existing regulations that were not yet part of Colorado's Ozone SIP. The Commission adopted many of these rules in 2014, and intends to preserve the substance of these rules, where possible, in moving them into the Ozone SIP, while making a few adjustments and improvements in response to recommendations in the Oil and Gas CTG. The Commission also adopted correlating revisions to the applicability provisions of Sections II. and XII.

The Commission relied on existing regulations in the Ozone SIP for RACT for condensate storage tank controls to satisfy Colorado's obligation to address storage vessels under the Oil and Gas CTG. The Commission adopted requirements for pneumatic pumps in Section XII. to address recommendations in the Oil and Gas CTG. The Commission revised the existing SIP requirements in Section XII.G. for equipment leaks at natural gas processing plants to address recommendations in the Oil and Gas CTG. The Commission duplicated into the Ozone SIP from Section XVII. provisions for compressors and leak detection and repair ("LDAR") for components at well production facilities and natural gas compressor stations. The Commission adjusted these LDAR requirements to address recommendations in the Oil and Gas CTG, along with updates to the recordkeeping and reporting requirements. Corresponding revisions to the LDAR program in Section XVII. are made on a State Only basis. The Commission also revised Section XVIII. to include existing State Only requirements for continuous bleed, natural gas-driven pneumatic controllers in the Ozone SIP and specify that continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants maintain a natural gas bleed rate of zero scfh.

The Commission adopted State Only provisions for the inspection and maintenance of natural gas-driven pneumatic controllers in Section XVIII.

The Commission also made clarifying revisions and corrected typographical, grammatical, and formatting errors found within the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

<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 above, the Commission believes that the process to review and potentially approve alternative monitoring methods is sufficiently constrained such that EPA, when approving the process, can be assured as to what emission reductions any such alternative monitoring will achieve in the context of the Section XII.L. LDAR program. However, the Commission also recognizes EPA's technical knowledge and is requiring the Division to continue to engage with EPA concerning alternative monitoring methods. Specifically, the Division must provide complete applications to EPA early in the review process, which has previously ranged from three to nine months. The Division must also provide EPA six (6) months after approval of an alternative for further EPA review. The Commission believes this process provides sufficient time for meaningful engagement with EPA.

Clarifications

The Commission is clarifying, both in Section XII.L. and Section XVII.F., that all detected emissions are leaks, but that only those leaks above specified thresholds require repair. The Commission did not intend that leaks falling below the specified thresholds would not be considered "leaks," only that those leaks did not require repair in accordance with the prescribed schedules. The Commission has further clarified that only records of leaks requiring repair need to be maintained.

Regulation Number 7 already requires that owners or operators remonitor repaired leaks with an AIMM. AIMM includes EPA Method 21, which includes the soapy water method, and the Commission further clarifies that an owner or operator may use the soapy water method in EPA Method 21 to remonitor a repaired leak.

Some stakeholders asked the Commission to "clarify" that the LDAR repair, remonitoring, recordkeeping, and reporting requirements applied only to those leaks discovered by the owner or operator, and not those discovered by the Division. The Commission believes that would not be a clarification, but a change to the current program, and does not make that requested revision at this time. Therefore, the repair, remonitoring, recordkeeping, and reporting requirements continue to apply to leaks discovered by the Division.

<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 above, malfunctioning pneumatic controllers can result in significant hydrocarbon emissions. The DMNFR ozone nonattainment area is currently classified as a Moderate nonattainment area under the 2008 ozone NAAQS. The deadline for the DMNFR to attain the 2008 ozone NAAQS is July 2, 2018. If the DMNFR does not attain the standard or does not receive an extension, EPA may reclassify the DMNFR as a Serious nonattainment area under the 2008 ozone NAAQS. In addition, the Commission approved a designation recommendation for the DMNFR under the 2015 ozone NAAQS in September 2016. While EPA has not yet acted on this recommendation, the Commission expects the DMNFR will be designated as nonattainment under the 2015 ozone NAAQS and is taking action to promote attainment of the more stringent standard. Given both the potential for a reclassification to Serious under the 2008 ozone NAAQS and the need to reduce ozone to meet the more stringent 2015 ozone NAAQS, the Commission is adopting the State Only pneumatic controller inspection requirements that further reduce ozone precursors emissions, notwithstanding the fact that a pneumatic controller inspection program is not specified as presumptive RACT in the Oil and Gas CTG.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission. The EPA revised the ozone NAAQS in 2015 and the DMNFR must attain the new standard or face additional requirements. The revisions to Regulation Number 7 address RACT for compressors, pneumatic pumps, pneumatic controllers, natural gas processing plants, natural gas compressor stations, and well production facilities. The revisions apply to equipment already regulated by Colorado on a State Only basis and apply to equipment not previously subject to regulation. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to the regulated equipment. The Commission determined that the adopted RACT SIP requirements are comparable to the Oil and Gas CTG's recommendations. The Commission also determined that there are not comparable federal rules requiring the inspection and maintenance of natural gas-driven pneumatic controllers.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa to allow an owner or operator to request EPA approve compliance with an alternate emission limitation (e.g., alternative monitoring, state program) instead of related requirements in NSPS OOOOa.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here. Further, the State Only pneumatic controller inspection requirements address the lack of federal requirements concerning emissions from malfunctioning pneumatic controllers.

(IV) Unless federal law changes, Colorado will be required to comply with the more stringent 2015 ozone NAAQS in the near future and may be required to comply with the more stringent requirements for a Serious nonattainment area. These current SIP and State Only revisions may improve the ability of the regulated community to comply with new, more stringent, future requirements. In addition, these revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommended oil and gas RACT provisions.

(V) EPA has established October 27, 2018, deadline for this SIP submission. EPA has not yet established deadlines for the DMNFR to attain the 2015 ozone NAAQS. However, given the potential reclassification of the DMNFR to Serious under the 2008 ozone NAAQS, the Commission determined that taking action to reduce ozone precursor emissions as soon as practicable, either as part of the SIP or on a State Only basis, is warranted.

(VI) The revisions to Regulation Number 7 Sections XII. and XVIII. strengthen Colorado's SIP and State Only provisions, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(VII) The revisions to Regulation Number 7 Sections XII. and XVIII., including the State Only provisions, establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, or qualify for an extension of the attainment deadline, EPA will likely reclassify Colorado as a Serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs. The State Only rule revisions are expected to reduce future costs by achieving emissions reductions that will assist the DMNFR in attaining both the 2008 and 2015 ozone NAAQS thus avoiding additional ozone nonattainment area CAA requirements.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The State Only pneumatic controller inspection program is tailored to be consistent with the SIP required LDAR program, thereby reducing costs related to pneumatic controller inspections.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants. Further, pneumatic controller inspections will be conducted using accepted technologies and some owners or operators already repair and maintain pneumatic controllers.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP. The Commission determined that the Division's proposal was reasonable and cost-effective. The Commission further determined the State Only natural gas-driven pneumatic controller inspection program is reasonable and cost-effective, given the potential for reducing emissions from malfunctioning pneumatic controllers and the absence of federal requirements addressing pneumatic controller emissions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's Ozone SIP to address the Moderate nonattainment area requirements. Colorado must also continue to reduce ozone concentrations to address both the possibility of reclassification under the 2008 ozone NAAQS and the 2015 ozone NAAQS. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, including regulatory changes made on a State Only basis, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC.

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

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

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

XX.Q. July 19, 2018 (Sections XVI. and XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e. sources that emit or have the potential to emit 100 tons per year ("tpy") or more). The CAA does not define RACT. However, EPA has defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53762 (Sept. 17, 1979). RACT can be adopted in the form of emissions limitations or work practice standards or other operation and maintenance requirements as appropriate.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions.

In response to the reclassification, the Commission revised Regulation Number 7 to satisfy RACT SIP requirements for Moderate nonattainment areas by establishing categorical RACT requirements for major sources of VOC and/or NOx in the DMNFR. Specifically, the Commission adopted RACT requirements in Section XVI.D. for existing boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces, and compression ignition reciprocating internal combustion engines ("RICE") (collectively referred to as "stationary combustion equipment") located at major sources of NOx in the DMNFR as of June 3, 2016.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Major VOC and NOx source RACT

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. The following sources were known by the Commission to be major sources of VOC and/or NOx as of June 3, 2016 and were analyzed in Colorado's Moderate Area SIP for the 2008 8-Hour Ozone NAAQS:

Anheuser-Busch, Fort Collins Brewery (069-0060) and Nutri-Turf (123-0497) (major for VOC and NOx)

Ball Metal Beverage Container Corporation (059-0010 major for VOC)

Buckley Air Force Base (005-0028 major for NOx)

Carestream Health (123-6350 major for NOx)

Cemex Construction Materials (013-0003 major for VOC and NOx)

Colorado Interstate Gas, Latigo (005-0055 major for NOx)

Colorado Interstate Gas, Watkins (001-0036 major for VOC and NOx)

Colorado State University (069-0011 major for NOx)

CoorsTek (059-0066 major for VOC)

Corden Pharma Colorado (013-0025 major for VOC)

DCP Midstream, Enterprise (123-0277 major for VOC and NOx)

DCP Midstream, Greeley (123-0099 major for VOC and NOx)

DCP Midstream, Kersey/Mewbourn (123-0090 major for VOC and NOx)

DCP Midstream, Lucerne (123-0107 major for VOC and NOx)

DCP Midstream, Marla (123-0243 major for VOC and NOx)

DCP Midstream, Platteville (123-0595 major for VOC and NOx)

DCP Midstream, Roggen (123-0049 major for VOC and NOx)

DCP Midstream, Spindle (123-0015 major for VOC and NOx)

Denver Regional Landfill, Front Range Landfill, Timberline Energy (123-0079 major for NOx)

Elkay Wood Products (001-1602 major for VOC)

IBM Corporation (013-0006 major for NOx)

Kerr-McGee Gathering, Frederick (123-0184 major for VOC and NOx)

Kerr-McGee Gathering, Hudson (123-0048 major for VOC and NOx)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057 major for VOC and NOx)

Kodak Alaris (123-0003 major for VOC)

Metal Container Corporation (123-0134 major for VOC)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery, Rocky Mountain Metal Container (059-0006), MMI/EtOH (059- 0828), and Colorado Energy Nations Company, LLC (059-0820) (major for VOC and NOx)

Owens-Brockway Glass (123-4406 major for NOx)

Phillips 66 Pipeline, Denver Terminal (001-0015 major for VOC)

Plains End (059-0864 major for VOC and NOx)

Public Service Company, Cherokee (001-0001 major for NOx)

Public Service Company, Denver Steam Plant (031-0041 major for NOx)

Public Service Company, Fort Lupton (123-0014 major for NOx)

Public Service Company, Fort Saint Vrain (123-0023 major for NOx)

Public Service Company, Rocky Mountain Energy Center (123-1342 major for NOx)

Public Service Company, Valmont (013-0001 major for NOx)

Public Service Company, Yosemite (123-0141 major for NOx)

Public Service Company, Zuni (031-0007 major for NOx)

Rocky Mountain Bottle Company (059-0008 major for NOx)

Sinclair Transportation Company, Denver Terminal (001-0019 major for VOC)

Spindle Hill Energy (123-5468 major for NOx)

Suncor Energy, Commerce City Refinery Plants 1, 2, and 3 (001-0003 major for VOC and NOx)

Thermo Cogeneration, JM Shafer (123-0250 major for NOx)

Tri-State Generation, Frank Knutson (001-1349 major for NOx)

TRNLWB, LLC (Trinity Construction Materials, Inc.) (059-0409 major for NOx)

University of Colorado Boulder (013-0553 major for NOx)

WGR Asset Holding, Wattenberg (001-0025 major for VOC and NOx)

Many of the major sources listed above are subject to regulatory RACT requirements. Some of the sources or source emissions points are subject to regulatory RACT requirements in Colorado's SIP; other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement of inclusion of an applicable federal New Source Performance Standards ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado must include in the SIP, provisions to implement RACT for Colorado's major sources. During the November 17, 2016 rulemaking, the Commission adopted source specific RACT for a number of major sources of VOC and/or NOx (again greater than or equal to 100 tons per year) in the DMNFR. These were originally adopted as Sections XIX.C.-XIX.G. for stationary combustion turbines, stationary internal combustion engines, wood furniture manufacturing, and municipal landfills, respectively, during the November 17, 2016 rulemaking. These sections have changed to Sections XVI.D.4.b. and XIX.A.-D. during this July 19, 2018 rulemaking, where requirements for stationary combustion turbines were removed and consolidated into Section XVI.D.4.b. The original Section XIX.C.-XIX.G. RACT requirements became effective on January 1, 2017. However, during the November 17, 2016 rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Regulation 3, Part F. Therefore, the Commission opted to adopt RACT for Colorado's existing major sources of NOx on a categorical basis in this July 19, 2018 rulemaking.

Establishing RACT on a categorical basis is a distinctly different process from Colorado's minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process), and the designs of which can more easily accommodate changes prior to construction. Categorical RACT applies much more broadly to source category, including both existing sources/equipment and new/modified sources/equipment. This inclusion of existing equipment significantly impacts costs, as those sources are not already committed to a capital expenditure and any associated shut down to add controls. This ultimately impacts the decision on what controls are determined to be reasonably available, technologically and economically feasible for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement.

To determine RACT on a categorical basis, the Commission required specific owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NOx emissions from the facility or emission point(s), propose RACT for that facility or point(s), propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). The following major sources were required to submit RACT analyses:

Anheuser-Busch (069-0060) – emission points equal to or greater than 2 tpy VOC or 5 tpy NOx

Buckley Air Force (005-0028) – engines and engine test cell (pt 102, 103, 104, 105, 101)

Carestream Health (123-6350) – boilers (pt 004)

Colorado Energy Nations Company, LLC (059-0820) – boilers (pt 001, 002)

Colorado Interstate Gas, Latigo (005-0055) – engines (001, 011)

Colorado Interstate Gas, Watkins (001-0036) – engines (001, 002)

Colorado State University (069-0011) – boilers (pt 003, 005, 007, 013)

IBM (013-0006) – engines and boilers (pt 088, 090, 001, 011, 095)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057) – turbine (pt 052) and engines (pt 038 through 044, and 047 through 049)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery (059-0006) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

MMI/EtOH (059-0828) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Nutri-Turf (123-0497) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Owens-Brockway (123-4406) – emission points with emissions equal to or greater than 5 tpy NOx (pt 001-023, 025)

Public Service Company, Cherokee (001-0001) – turbines (pt 028, 029)

Public Service Company, Fort Saint Vrain (123-0023) – turbines (pt 010, 011, 001)

Public Service Company, Denver Steam Plant (031-0041) – boilers (pt 001, 002)

Public Service Company, Zuni (031-0007) – boilers (pt 001, 002, 003)

Public Service Company, Fort Lupton (123-0014) – turbines (pt 001, 002)

Public Service Company, Valmont (013-0001) – turbine (pt 002)

Rocky Mountain Bottle (059-0008) – glass melt furnaces (pt 001)

Suncor (001-0003) – boilers (pt 309, 019, 021, 023)

Tri-State Generation and Transmission, Frank Knutson (001-1349) – turbines (pt 001, 003)

TRNLWB, LLC (Trinity Construction Materials) (059-0409) – shale kiln (pt 001)

University of Colorado (013-0553) – Power House and East District – boilers (pt 001, 002, 012, 013) and Williams Village– boilers (pt 016, 017)

WGR Asset Holding, Wattenberg (001-0025) – boiler (pt 012), turbine and duct burner (pt 021) and engines (pt 004 and 018)

Based on the information provided in these RACT analyses as well as the Division's own in-depth review of rules adopted by Moderate nonattainment areas in other states and EPA guidance such as the RACT/BACT/LAER Clearinghouse, the Commission adopted RACT requirements in Section XVI.D. for stationary combustion equipment located at existing major sources of NOx in the DMNFR. The requirements of Section XVI.D. only apply to existing stationary combustion equipment located at sources in the DMNFR that were major for NOx as of June 3, 2016 (i.e. the effective date of the DMNFR's reclassification to Moderate nonattainment).

Definitions

The definition for "stationary combustion equipment" refers to individual emission points and not grouped emission points.

Emission limitations and operational requirements

The Commission adopted categorical emission limitations (Section XVI.D.4.), which vary based on fuel type and size of the stationary combustion equipment, where applicable. Affected stationary combustion equipment is required to comply with these exemptions by October 1, 2021. This compliance period is necessary in order to allow affected sources sufficient time to complete any capital expenditures, install any control or monitoring equipment, and/or satisfy any permitting requirements necessary to comply with the applicable emission limitation. The heat input size threshold for determining whether an emission limitation applies refers to the maximum design value of the stationary combustion equipment. De-rated heat input is not the equivalent of maximum design value heat input. Therefore, stationary combustion equipment cannot simply de-rate to fall below the size threshold. For certain categories of stationary combustion equipment, if the equipment's heat input is below the applicability threshold for the emission limitations, then the equipment would still be required to comply with the combustion process adjustment requirements originally adopted by the Commission during the November 17, 2016 rulemaking (now in Section XVI.D.6.) The compliance date for the categorical emission limits (i.e. XVI.D.4 and XVI.D.5) is independent of the compliance date for the combustion process adjustment (i.e. XVI.D.6(b)(vi)(A)).The combustion process adjustment requirements shall apply as RACT to a particular piece of equipment in accordance with the applicability provision, Section XVI.D.6.a., regardless of whether or not that piece of equipment is subject to a categorical emission limit in Section XVI.D.4. As described in Section XVI.D.6.a., the combustion process adjustment requirements only apply to stationary combustion equipment with uncontrolled actual emissions of NOx equal to or greater than 5 tons per year located at major sources of NOx. For stationary combustion turbines, the heat input capacity threshold for the emission limitations takes into account to the heat input capacity of the stationary combustion turbine only and not the heat input capacity of the stationary combustion turbine and any duct burner that may be used.

For glass melting furnaces at major sources of NOx, the Commission adopted a production-based categorical emission limitation (Section XVI.D.4.d.). Emissions from some glass melting furnaces are routed through a common stack, where total emissions from multiple furnaces are monitored on a continuous basis. Where this is the case, the total emissions, as monitored from the common stack, shall be divided by the total glass production from all glass melting furnaces associated with the common stack to demonstrate compliance with the categorical RACT limit.

Exemptions

The Commission determined several exemptions from compliance with the categorical RACT standards to be appropriate for Colorado's source mix. In Section XVI.D.2.a., the Commission adopted a 20% capacity factor exemption for boilers and a 10% capacity factor exemption for stationary combustion turbines and compression ignition reciprocating internal combustion engines. The Commission established the 20% and 10% capacity factor exemptions, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units. The Commission determined that the capacity factor exemptions addressed each of these concerns, and thus that additional individual exemptions were not necessary beyond the capacity factor exemption.

At low capacities, controls are often cost prohibitive or technologically infeasible. The Commission determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the categorical standard or monitoring requirements. Many of the older boilers are not equipped with continuous emission monitoring systems ("CEMS") and may require add-on controls to comply with the categorical standard. The shift in capacity to newer, lower emitting boilers which are already equipped with NOx controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption for boilers provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall environmental benefit.

Some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating ("MCR"). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular low utilization boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard. The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard runs contrary to the original intent of reducing emissions, thus the Commission concludes that it is reasonable to allow exclusion of limited-use boilers from the categorical standard and associated CEMS requirements, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with the categorical standard. Consequently, the Commission determined that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.

For stationary combustion turbines and compression ignition RICE, a 10% capacity factor exemption from the proposed categorical emission standards and monitoring requirements is appropriate because combustion turbines and compression ignition RICE are more likely to operate during the summer months. Moreover, for turbines and compression ignition RICE that are used primarily for emergency power generation or peak demand, historic capacity factors are extremely low (0%-5%), and a 10% capacity factor exemption will provide enough operational flexibility to respond to emergency and peak demand events.

Separately, the categorical RACT for glass melting furnaces provides a 35% low usage allowance similar to capacity factor.

The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input. Alternatively, for electric generating units, the proposal allows for capacity factor to be determined based on electric output, which is consistent with the federal Acid Rain Program.

The Commission intended that the exemption for stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx was based on the permitting threshold in Regulation 3. Similarly, this equipment was not exempted from having to undergo a RACT analysis. The owner or operator must use the most recent air pollution emission notice ("APEN") submitted to the Division to determine total uncontrolled actual emissions.

Stationary combustion equipment that meets one of the exemptions contained in Section XVI.D.2. is not required to comply with the emission limitations, the compliance demonstration requirements and the related recordkeeping and reporting requirements contained in Sections XVI.D.4., XVI.D.5., XVI.D.7., and XVI.D.8., except for XVI.D.7.g, which requires a source that qualifies for an exemption under Section XVI.D.2., to maintain records demonstrating an exemption applies. All stationary combustion equipment is subject to some level of recordkeeping and may also be subject to combustion process adjustment requirements.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of Section XVI.D. as expeditiously as practicable but no later than 36 months after the equipment is no longer exempt. Therefore, if any stationary combustion equipment has to undertake a capital expenditure, such as installing a CEMS, in order to comply with Section XVI.D., then they have up to a maximum of three years to come into compliance. However, if no such capital expenditure or change in operational practice is required, then the stationary combustion equipment should comply sooner than three years (i.e. as expeditiously as practicable.) Additionally, once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations. This means that a source can fall into and out of having to comply with the emission limitation, monitoring, recordkeeping and reporting requirements of the rule if they satisfy the performance test requirements (i.e. the Division will not follow a “once in/always in” approach with respect to emission control requirements of exemptions.) Similarly, this 180 day period starts once the equipment is no longer exempt.

Monitoring, recordkeeping and reporting requirements

The Commission determined that affected stationary combustion equipment comply with certain monitoring, recordkeeping and reporting requirements by October 1, 2021. In order to provide clarity and regulatory certainty, many of the monitoring requirements adopted by the Commission incorporate by reference existing federal requirements and are consistent with rules in Moderate nonattainment areas in other states establishing RACT for these source categories.

The Commission is requiring CEMS or continuous emissions rate monitoring systems (“CERMS”) for boilers with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, lightweight aggregate kilns with a maximum heat input design capacity equal to or greater than 50 MMBtu/hr, and glass melting. CERMS may require a stack gas flow rate monitor, where necessary, in order to measure volumetric flow rate and mass emissions. Where stack gas velocity is extremely low, as may be the case for a glass melting furnace, flow can be measured using a Division approved calculation methodology if flow cannot be accurately measured using traditional differential pressure or ultrasonic flow measuring devices. Moreover, where measuring emission rates in terms of emissions per unit of heat input (i.e. lb/MMBtu), EPA Method 19 calculations may be used using the appropriate F factor (i.e. the ratio of combustion gas volumes to heat inputs). Further, it is the Commission’s intent to allow electric utility boilers and stationary combustion turbines subject to the Acid Rain Program to use the quality assurance/quality control and data validation procedures in 40 CFR Part 75 for monitoring emissions to satisfy monitoring, recordkeeping and reporting requirements in this rule. Affected units that are subject to a NOx emission limitation in an NSPS and use CEMS or CERMS to monitor compliance with that limit can use those monitoring, recordkeeping and reporting requirements to demonstrate compliance with this rule.

Similarly, owners or operators of stationary combustion turbines using performance testing to demonstrate compliance with NOx emission limitations of NSPS GG or KKKK may utilize those procedures for demonstrating compliance with the emission limitation in this rule. Where an initial performance test has already been conducted to determine compliance with NSPS GG or KKKK, it is not expected that another initial performance test must be performed for purposes of demonstrating compliance with Section XVI.D. Where an initial performance test has not been previously conducted, it must be completed by October 1, 2021 to demonstrate compliance.

For each initial or periodic test, sources should calculate the backup fuel's heat input for the calendar year prior to the year in which the performance test is required to determine if a test is required for each fuel or only for the primary fuel. Moreover, periodic performance tests must be conducted no more than 24 months apart.

With respect to the fuel flowmeter requirements, the Division reserves the right to audit quality assurance procedures with respect to manufacturer's instructions. The heat input measured and recorded by the fuel flowmeter is to be in the same unit of measurement as the applicable emission limitation. With respect to the quarterly or semi-annual reporting requirement, the Commission intended to only require that reports be submitted no less than semi-annually, but a source may submit quarterly reports in order to be consistent with existing reporting frequencies established in a permit and/or applicable NSPS or NESHAP.

With respect to the performance test reports, all performance test reports must compare average emissions determined by the performance test with the applicable emission limitation using the same number of significant figures as the emission limitation.

Incorporation by Reference in Sections XIX. and XVI.

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Sections XVI.D.5. and XIX.A. through D. by reference.

Additional Considerations

Colorado must revise its ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC and NOx in Colorado's ozone nonattainment area. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission adopted RACT requirements in Section XVI.D. for combustion equipment located at major sources of NOx in the DMNFR. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS Db, NSPS GG, NSPS KKKK, NSPS IIII, NSPS JJJJ, NSPS OOOO, NSPS OOOOa, and the compliance demonstration requirements in 40 CFR Parts 60 and 75 may apply to such stationary combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to specific existing stationary combustion equipment in the DMNFR.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in certain NSPS and MACT. Certain stationary combustion equipment with a lower heat input may trigger the combustion process adjustment work practice requirements of this rule.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7, Sections XVI. and XIX. establish categorical RACT for major sources of VOC and/or NOx, and thus are necessary to satisfy RACT SIP requirements for Moderate nonattainment areas and are specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The Revisions to Regulation Number 7, Sections XVI., and XIX. establish reasonable equity for major sources of VOC and/or NOx by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a 1-year clean data extension), EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal additional monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC and/or NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

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

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

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

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

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

Appendix A Colorado Ozone Nonattainment or Attainment Maintenance Areas

I. Chronology of Attainment Status

Denver Metropolitan Area Only

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

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

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

Denver Metropolitan Area and North Front Range

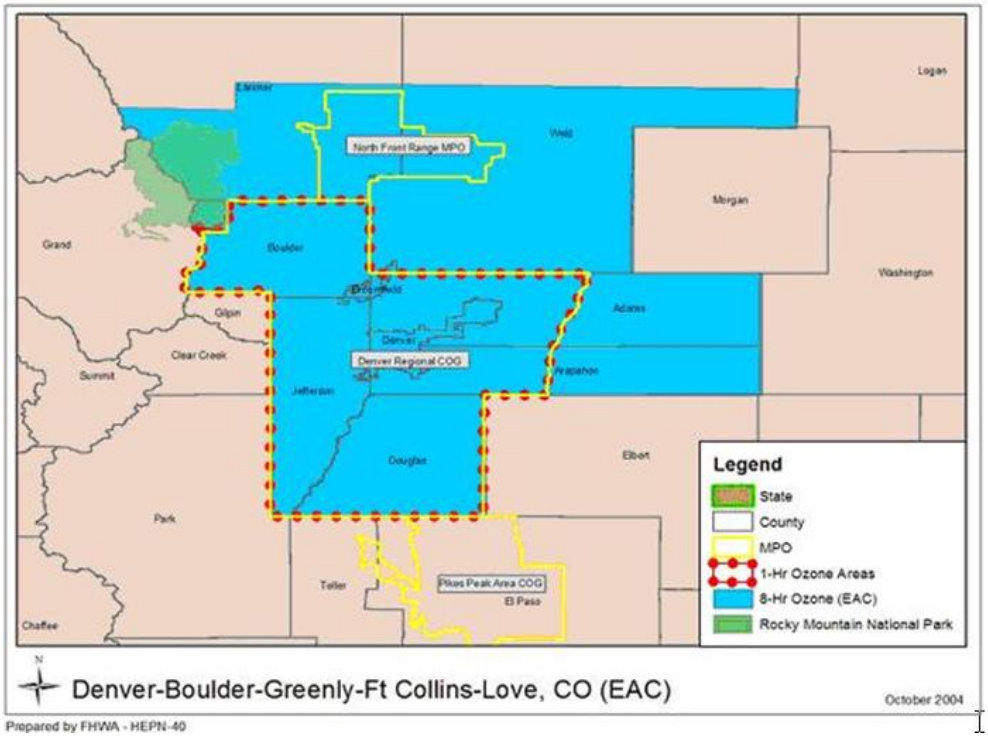
10/11/01 1-hour attainment maintenance area replaces non-attainment designation for the Denver Metro Area/North Front Range Area

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

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

II. Maps

Denver Metropolitan Area and North Front Range



Appendix B Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks

I. Drop Tube Specifications. Submerged fill is specifically required. The drop tube must extend to within 15.24 cm (6 in.) of the tank bottom.

II. Vapor Hose Return. Vapor return line and any manifold must be minimum 7.6 cm (3 in.) ID. All tanks must be provided with individual overfill protection. (Liquid must not be allowed in the vent line or vapor recovery line.) Disconnect on liquid line should assure that all liquid in the hose is drained into the storage tank. The requirements for overfill protection as specified may be waived for existing storage tanks when it is demonstrated to the satisfaction of the appropriate local Fire Marshal, and where applicable, the State Oil Inspection Office that the installation of overfill protection devices on existing tanks is physically not possible.

III. Size of Vapor Line Connections. For separate vapor lines, nominal three inch (7.6 cm) or larger connections must be utilized at the storage tank and truck. However, short lengths of 2-inch (5.1 cm) vertical pipe no greater than 91.4 cm (3 ft.) long are permissible if the fuel delivery rate is less than 400 gallons per minute.

Where concentric (coaxial) connections are utilized, a 45 cm2 (7 sq. in.) area for vapor return shall be provided. Four-inch concentric designs are acceptable only when using a venturi-shaped outer tube or where normal drop rate of 1,700 liters per minute (450 gpm) is reduced by at least 25%. Six-inch (15.24 cm) risers should be installed in new stations with concentric connections.

IV. Type of Liquid Fill Connection. Vapor tight caps are required for the liquid fill connection for all systems. A positive closure utilizing a gasket is necessary to prevent vapors from being emitted at ground level. Cam-lock closures meet this requirement. Dry break closures are preferred.

V. Tank Truck Inspection. Tank trucks are specifically required to be vapor-tight and to have valid leak-tight certification. The visual inspection procedure must be conducted at least once every six months to ensure properly operating manifolding and relief valves, using the test procedure of Appendix D.B.

VI. Dry Break on Underground Tank Vapor Riser. Dry-break closures are required to assure transfer of displaced vapors to the truck and to prevent ground-level, gasoline-vapor emissions caused by failure to connect the vapor return line to the underground tanks (closure on riser to mate with opening on hose). These devices keep the tank sealed until the hose is connected to the underground tank. Concentric couplers without dry-breaks are required to have a dry-break on the vapor line connection to the coupler itself, rather than on the rise pipe from the storage tank. The liquid fill riser should be provided with a gap having a positive closure (threaded or latched).

VII. Equipment Ensuring Vapor-Hose Connection During Gasoline Deliveries. An equipment system aboard the tank truck shall insure (barring deliberate tampering) that a vapor return hose is connected from the truck's vapor return line to the tank receiving gasoline.

VIII. Vent Line Restriction Devices. Vent line restriction devices are required. They both improve recovery efficiency and, as an integral part of any system, assure that the vapor return line is connected during transfer. If the liquid fill line were attached to the underground tank and the vapor return line were disconnected, then dry break closures would seal the vapor return path to the truck, forcing all vapors out the vent line. In such instances, a restriction device on this vent line greatly reduces fill rate, warning the operator that the vapor line is not connected. Both of the following devices must be used.

(a) An orifice of one-half to three-fourth inch (1.25 - 1.9 cm) ID.

(b) A pressure/vacuum relief valve set to open at (1) a positive gauge-pressure greater or equal to five inches of water (9 torr) and at (2) a negative gauge-pressure greater or equal to five inches of water (9 torr).

IX. Fire and Safety Regulations. All new or modified installations must comply in their entirety with all code requirements including NFPA, Pamphlet 30 (fiberglass is preferred for new manifold lines). For any questions concerning compliance, please contact State Oil Inspection or your local Fire Marshal.

X. State Oil Inspection. Requirements of the State Oil Inspection office make accurate measurements of the liquid in the underground tank necessary. Vapor-tight gauging devices will be required in all systems designed such that a pressure other than atmospheric will be held or maintained in the storage tank. The volume of liquid in the tanks maintained at atmospheric pressure may be determined with a stick through the submerged drop tube or through a separate submerged gauging tube extending to within 15.24 cm (6 in.) of the tank bottom.

Appendix C Criteria for Control of Vapors From Gasoline Transfer at Bulk Plants (Vapor Balance System)

I. Storage Tank Requirements:

A. Drop Tube Specification: Underground tanks must contain a drop tube that extends to within six inches (15.24 cm) of the tank bottom. All top loaded above-ground tanks must contain a similar drop tube. Above-ground tanks using bottom loading, where the inlet is flush with the tank bottom, must meet the submerged fill requirement.

B. Size of Vapor Lines from Storage Tanks to Loading Rack: See nomograph (Attachment 1). NOTE: Affected sources are free to choose a pipe diameter different from the one suggested by the nomograph if sufficient justification and documentation is presented.

C. Pressure Relief Valves: All pressure relief valves and valve connections must be checked periodically for leaks, and be repaired as required. The relief valve pressures should be set in accordance with Sections 2-2.5.1 and 2-2.7.1 inclusive of the current National Fire Protection Agency Pamphlet Number 30.

D. Liquid Level Check Port: Access for checking liquid level by other than a vapor-tight gauging system shall be vapor-tight when not being used. Tank level shall be checked prior to filling to avoid overfills.

E. Miscellaneous Tank Openings: All other tank openings, e.g., tank inspection hatches, must be vapor tight when not being used, and must be closed at all times during transfer of fuel.

F. Storage Tank Overfill Protection: Except for concentric (coaxial) delivery systems, underground tanks must have ball check valves (stainless steel ball). Tanks with concentric delivery systems must have Division-approved overfill protection, (e.g., cutoff pressure-switch in vent line).

II. Loading Rack Requirements:

A. Loading Specification: A vapor-tight bottom-loading or top-loading system using submerged fill with a positive seal, e.g., the Wiggins (tm) system, is required. NOTE: Bulk plants delivering solely to exempt accounts are required to have submerged fill, but loading need not be vapor-tight.

B. Dry-Break on Storage Tank Vapor Return Line: A dry-break is required to prevent ground-level gasoline vapor emissions during periods when gasoline transfer is not being made. This device keeps the tank sealed until the vapor return hose is connected.

III. Tank Truck* Requirements:

A. Vapor Return Modification: Tank trucks must be modified to recover vapors during loading and unloading operations. NOTE: Tank trucks making deliveries solely to exempt accounts do not require this modification. However, 97% submerged fill is required when top loading.

B. Loading Specifications: Bottom loading or top loading using submerged fill with a positive seal is required for tank trucks modified for vapor recovery. NOTE: When loading a tank truck with this modification without the vapor return hose connected (this is allowed at bulk plants servicing exempt accounts returning without collected vapors in the tank), the requirements of National Fire Protection Agency Pamphlet Number 385, "Loading and Unloading Venting Protection in Tank Vehicles, Section 2219, Paragraph c", must be met.

C. Vapor Return Hose Size: A minimum three-inch (7.6 cm) ID vapor return hose is required.

D. Tank Truck Inspection: Tank trucks are required to be vapor-tight and have valid leak-tight certification. Periodic visual inspection is necessary to insure properly operating manifolding and relief valves.

* The term "tank truck" is meant to include all trucks with tanks used for the transport of gasoline, such as tank wagons, account trucks and transport trucks.

Appendix D Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers

The specifications in this Appendix apply only to vapor degreasers that have both condenser coils and refrigerated freeboard chillers. (The coolant in the condenser coils is normally water.) The amount of refrigeration capacity is expressed in Calories/Hour per meter of perimeter. This perimeter is measured at the air/vapor interface.

For refrigerated chillers operated below 0°C., the following requirements apply:

DEGREASER WIDTH	*CALORIES/HR METER OF PERIMETER	BTU/HR FOOT OF PERIMETER
Less than 1.1 meters (3.5 ft.)	165	200
1.1 - 1.8 meters (3.5 - 6.0 ft.)	250	300
1.8 - 2.4 meters (6.0 - 8.0 ft.)	335	400
2.4 - 3.0 meters (8.0 - 10.0 ft.)	145	500
Greater than 3.0 meters (10 ft.)	500	600

* Kilocalories (1 Kilocalorie = 4184.0 joules)

For refrigerated chillers operating above 0°C., there shall be at least 415 Calories/Hr. - meter of perimeter (500 BTU/Hr-ft.), regardless of size.

Definition:

"Air/Vapor Interface" - means the surface defined by the top of the solvent vapor layer within the confines of a vapor degreaser.

Appendix E Test Procedures for Annual Pressure/Vacuum Testing of Gasoline Transport Tanks

A. Testing

The delivery tank, mounted on either the truck or trailer, is pressurized isolated from the pressure source, and the pressure drop recorded to determine the rate of pressure change. A vacuum test is to be conducted in a similar manner. The Division shall provide forms which designate all required information to be recorded by the testing agency.

B. Visual Inspection

The entire tank, including domes, dome vents, cargo tank, piping, hose connections, hoses and delivery elbows, shall be inspected for wear, damage, or misadjustment that could be a potential leak source. Inspect all rubber fittings except those in piping which are not accessible. Any part found to be defective shall be adjusted, repaired, or replaced as necessary. (Safety note: it is strongly recommended that testing be done outside, unless tank is first degassed (e.g., steamcleaned). No “hot work” or spark-producing procedures should be undertaken without first degassing).

C. Equipment Requirements

1. Necessary equipment.

a. Source of air or inert gas of sufficient quantity to pressurize tanks to 27.7 inches of water (1.0 psi; 52 torr) above atmospheric pressure.

b. Water manometer with 0 to 25 inch range (0-50 torr); with scale readings of 0.1 inch (or 0.2 torr).

c. Test cap for vapor line with a shut-off valve for connection to the pressure and vacuum supply hoses. The test cap is to be equipped with a separate tap for connecting with manometer.

d. Cap for the gasoline delivery hose.

e. Vacuum device (aspirator, pump, etc.) of sufficient capacity to evacuate tank to ten (10) inches of water (20 torr).

2. Recommended equipment

a. In-line, pressure-vacuum relief valve set to activate at one (1) psi (52 torr) with a capacity equal to the pressurizing or evacuating pumps. (Note: This is a safety measure to preclude the possibility of rupturing the tank).

b. Low pressure (5 psi (250 torr) divisions) regulator for controlling pressurization of tank.

D. Vacuum and Pressure Tests of Tanks

1. Pressure Test

a. The dome covers are to be opened and closed.

b. The tank shall be purged of gasoline vapor and tested empty. The tank may be purged by any safe method such as flushing with diesel fuel, or heating oil. (For major repairs it is recommended that the tank be degassed by steam cleaning, etc.)

c. Connect static electrical ground connections to tank. Attach the delivery and vapor hoses, remove the delivery elbows and plug the liquid delivery fittings. (The latter can normally be accomplished by shutting the delivery valves).

d. Attach the test cap to the vapor recovery line of the delivery tank.

e. Connect the pressure (or vacuum) supply hose and, optionally, the pressure-vacuum relief valve to the shut-off valve. Attach a manometer to the pressure tap on the vapor-hose cap. Attach pressure source to the hose.

f. Connect compartments of the tank internally to each other if possible.

g. Open shut-off valve in the vapor recovery hose cap. Applying air pressure slowly, pressurize the tank, or alternatively the first compartment, to 18 inches of water (35 torr).

h. Close the shut-off valve, allow the pressure in the delivery tank to stabilize (adjust the pressure if necessary to maintain 18 inches of water (35 torr), record the time and initial pressure; begin the test period.

i. At the end of five (5) minutes, record the final time, pressure, and pressure change. Disconnect the pressure source from the pressure/vacuum supply hose, and slowly open the shut-off valve to bring the tank to atmospheric pressure.

j. Repeat for each compartment if they were not interconnected.

2. Vacuum Test

a. Connect vacuum source to pressure and vacuum supply hose.

b. Slowly evacuate the tank, or alternatively the first compartment, to six (6) inches of water (12 torr). Close the shut-off valve, allow the pressure in the delivery tank to stabilize (adjust the pressure if necessary to maintain six (6) inches of water (12 torr) vacuum), record the initial pressure and time; begin the test period. At the end of five (5) minutes, record the final pressure, time, and pressure change.

c. Repeat for each compartment if they were not interconnected.

E. Leak Check of Vapor Return Valve

1. After passing the vacuum and pressure tests, by making any needed repairs, pressurize the tank as in Appendix E, paragraph D.1. to eighteen (18) inches of water (35 torr).

2. Close the internal valve(s) including the vapor valve(s) and “fire valves.”

3. Relieve the pressure in the vapor return line to atmospheric pressure, leaving relief valve open to atmospheric pressure.

4. After five (5) minutes, seal the vapor return line by closing relief valve(s). Then open the internal valves including the vapor valve(s) and record the pressure, time, and pressure change. (To trace a leaking vapor valve it may be advantageous to open each vapor valve one at a time and record the pressure after each.)

5. The leak rate attributed to the vapor return valve shall be calculated by subtracting the pressure change in the most recent pressure test per Appendix E, paragraph D.1.i. from the pressure change in E.4.

Appendix F Emission Limit Conversion Procedure

The following procedure shall be used to convert emission limits expressed as lb VOC/gallon coating less water and exempt solvents to limits expressed as lb VOC/gallon solids. This example uses the emission limit of 3.7 lb VOC/gallon coating.

Assume VOC density of the `Presumptive' RACT coating is 7.36 pounds per gallon because this same value was used to determine the "Presumptive" recommended RACT emission limits from volume solids data.

(3.7) LB VOC / GAL COATING LESS WATER x I GAL VOC x 100 / 7.36 LB VOC = (50) V0L% VOC

100 - (50) V0L% VOC = (50) V0L% SOLIDS

(3.7) LB VOC / GAL COATING LESS H2O x 100 GAL COATING / (50) GAL SOLIDS = (7.4) LB VOC / GAL SOLIDS

See "A Guideline For Surface Coating Calculations" EPA - 340/1-86-0l6 for additional examples.

The following table lists equivalent mass VOC/volume solids emission limits for various coating operations.

Equivalency Data for Surface Coating Processes
(VOC Density = 7.36 lb/gal)

Industrial Finishing Categories	Lb VOC per Gallon Coating less water	Lb VOC per Gallon of Solids	Kg VOC per Liter of Solids
Can Industry			
Sheet Basecoat (Exterior and Interior) and over-varnish; two-piece can exterior (base-coat and over-varnish)	2.8	4.5	0.55
Two- and three-piece can interior body spray, two-piece can exterior end spray or roll coat	4.2	9.8	1.19
Three-piece can side-seam spray	5.5	21.7	2.61
End sealing compound	3.7	7.4	0.88
Any additional coats	4.2	9.8	1.19
Coil Coating			
Any coat	2.6	4.0	0.48
Fabric Coating			
Fabric coating line	2.9	4.8	0.58
Vinyl coating line	3.8	7.9	0.93
Paper Coating			
Coating line	2.9	4.8	0.58

Automotive and Light-Duty Truck Assembly Plant			
Primer (electrodeposition) application, flashoff area and oven	1.9	2.6	0.31
Topcoat application, flashoff area and oven	2.8	4.5	0.55
Final repair application, flashoff area and oven	4.8	13.8	1.67
Metal Furniture			
Coating line	3.0	5.1	0.61
Magnet Wire			
Wire coating operation	1.7	2.2	0.26
Large Appliances			
Prime, single, or topcoat application area, flashoff area and oven	2.8	4.5	0.55
Miscellaneous Metal Parts and Products			
Air-dried items	3.5	6.7	0.80
Clear-coated items	4.3	10.3	1.25
Extreme performance coatings	3.5	6.7	0.80
Other coatings and systems	3.0	5.1	0.61
Plastic Film Coating			
Plastic film coating line	2.9	4.8	0.58

Editor's Notes

History

Entire rule eff. 01/30/2009.

Parts I.A.1, XVII, XIX.L eff. 02/14/2011

Parts II.D, XII.D XII.H, XVII.D, XIX.M eff. 02/15/2013.

Parts II.B, VI.B.2.a.(i)(E), IX.A.12.a.(x), XVII XVIII, XIX.B, XIX.N eff. 04/14/2014.

Parts 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.

Parts XVI, XIX, XX.Q eff. 09/14/2018.