AGENDA ITEM CONTROL SHEET

Item Title: Regulation Number 7, Sections II., XII., XVII., XVIII.

Meeting Date: July 20, 2017

TYPES OF ACTION

NON-HEARING ACTIONS	*REQUEST FOR HEARING*	*HEARING*
☐ Administrative	X Rulemaking	☐ Rulemaking
☐ Briefing	☐ Public	☐ Public
☐ Policy	☐ Adjudicatory	☐ Adjudicatory
☐ Other	☐ Informational	☐ Informational

Is this action a Rule Review? ☐ Yes X No

RECOMMENDED ACTION

☐ Adoption X Approval ☐ Denial

MOTION

☐ Required ☐ Attached ☐ Not Applicable

STATUTORY AUTHORITY

☐ General X Specific

CRS §§ 25-7-105(1), 102, 106, 109, and301

EPA SUBMITTAL

Is this issue considered a SIP revision? Yes, in part (Section XII and portions of Section XVIII)

Which SIP? Ozone Moderate Nonattainment Area SIP (2008 8-Hour Ozone NAAQS)

EPA submission deadline: October 27, 2018

Is this a delegated program? No

ISSUE STATEMENT:

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, Colorado submitted 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 Air Quality Control Commission ("Commission") submitted the November SIP revisions to EPA on May 31, 2017.

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. See attached comparison tables. The Division now requests that the Commission consider proposed revisions to Regulation Number 7 to include RACT requirements for each category of sources covered by EPA's Oil and Gas CTG in Colorado's Ozone SIP. These proposed revisions duplicate existing State-Only requirements for inclusion in Colorado's Ozone SIP, propose new requirements for inclusion in Colorado's Ozone SIP, and revise and/or clarify existing SIP and State-Only provisions.

Specifically, the Division proposes to duplicate the centrifugal and reciprocating compressor emission control requirements from existing Regulation Number 7, Section XVII.B.3. in proposed Section XII.J., along with new monitoring and recordkeeping requirements. The Division also proposes to create a well production facility and natural gas compressor station leak detection and repair ("LDAR") program in proposed Section XII.L., generally consistent with the existing State-Only program in Section XVII.F. but increasing the inspection frequency for smaller well production facilities and natural gas compressor stations. The Division proposes to include new pneumatic pump emission control, monitoring, and recordkeeping requirements in proposed Section XII.K. The Division's proposal includes provisions to increase the stringency of the LDAR program for equipment leaks at natural gas processing plants in existing SIP Section XII.G. The Division proposes to incorporate some of the existing Section XVIII. State-Only requirements for natural gas actuated, continuous bleed pneumatic controllers into the SIP and to require, as part of the SIP, zero bleed pneumatic controllers at natural gas processing plants.

In addition, the Division proposes State-Only revisions that require owners or operators of natural gas-driven pneumatic controllers located at a well production facility or natural gas compressor station in the DMNFR to inspect and maintain pneumatic controllers. Current information indicates these devices are a large source of emissions and that maintenance and repair can cost-effectively reduce excess emissions. The Oil and Gas CTG does not specifically recommend pneumatic controller inspection and maintenance provisions as RACT; therefore, the Division proposes to include these requirements as State-Only revisions.

These proposed revisions satisfy Colorado's Moderate CAA requirements and obtain emission reductions necessary to help the DMNFR attain the 2008 8-hour ozone NAAQS.

Further, the Division may also make clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7, Sections II., XII. and some revisions to Section XVIII. are SIP revisions. The proposed revisions to Section XVII. and some revisions to Section XVIII. are State-Only.

PROPOSAL:

The Division is proposing revisions to Regulation Number 7 to address EPA's Oil and Gas CTG that build on upon existing Regulation Number 7 requirements. The Division is also proposing additional revisions to Regulation Number 7 to secure emission reductions that will help the DMNFR attain the 8-hour ozone NAAQS.

A. Ozone SIP control measures addressing EPA's Oil and Gas CTG

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, compressors, pneumatic controllers, pneumatic pumps, equipment leaks at natural gas processing plants, and fugitive emissions in the Oil and Gas CTG. 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 emission reduction 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 EPA policies on interpreting RACT.

The Division compared the Oil and Gas CTG to existing requirements in Regulation Number 7 and is proposing revisions to the existing requirements for compressors, pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emissions at well production facilities and natural gas compressor stations to address the Oil and Gas CTG's recommendations. The Division is also proposing new requirements for pneumatic pumps to address the Oil and Gas CTG's recommendations. For a summary comparison, see the attached tables comparing the Oil and Gas CTG to Regulation Number 7.

a. Storage vessels

Colorado's Ozone SIP currently includes adequate requirements to control emissions from condensate storage tanks in the DMNFR; therefore, the Division is not proposing substantive revisions to the existing SIP Section XII. provisions concerning storage tanks.

The Oil and Gas CTG recommends that owners or operators reduce VOC emissions from individual storage vessels with the potential to emit greater than or equal to six tons per year ("tpy") VOC by 95%, or maintain storage vessel VOC emissions at less than four tpy uncontrolled actual VOC. The Oil and Gas CTG applies to storage vessels that contain crude oil, condensate, intermediate hydrocarbon liquid, or produced water in the oil and natural gas industry production, processing, and transmission and storage segments.

Regulation Number 7, Section XII. requires that owners or operators of condensate storage tanks at oil and gas exploration and production operations, natural gas compressor stations, and natural gas drip stations located upstream of a natural gas processing plant that emit greater than two tpy of actual uncontrolled VOC reduce VOC emissions from their condensate storage tank system by 90% on a weekly basis from May 1 to September 30 and by 70% on a monthly basis from October 1 to April 30 (the "system-wide" program). Section XII. defines condensate storage tank to include any tank or series of tanks that are either manifolded together or located at the same well pad. The low applicability threshold and the regulation of tank batteries instead of individual storage vessels result in the control of emissions from more tanks under Colorado's system-wide program than the Oil and Gas CTG's recommended RACT (single tank $\geq$ 6 tpy controlled emissions). Section XII. also requires the owner or operator to inspect the air pollution control equipment at least weekly, maintain records of such inspections as well as the storage tanks identification and emissions, and submit semi-annual reports of the storage tanks and emissions. These requirements are currently part of Colorado's Ozone SIP.

The Division does not propose substantive revisions to Colorado's condensate storage tank system-wide program at this time. Currently, Regulation Number 7, Section XII. applies to more storage tanks than the Oil and Gas CTG recommendation as Section XII. applies to condensate storage tanks (single or battery) with uncontrolled actual VOC emissions greater than two tpy, while the Oil and Gas CTG applies only to storage vessels (individual) with the potential to emit greater than six tpy controlled emissions. For comparison, a six tpy controlled emission standard equates to a 120 tpy uncontrolled actual emission standard. Because Colorado's existing system-wide program addresses more storage tanks than the Oil and Gas CTG, Colorado's system-wide program obtains greater VOC emission reductions than the Oil and Gas CTG's recommended RACT. To support this demonstration, the Divisions points out that in 2016 the Section XII. system-wide reports showed that 5,867 condensate tanks/batteries reduced VOC emissions by 74,221 tpy. In contrast, looking at a potential impact of the Oil and Gas CTG storage vessel program, Colorado's inventory shows that 95% control of individual condensate, crude, or produced water storage vessels with the potential to emit greater than six tpy controlled VOC (i.e., the Oil and Gas CTG applicability standard) would reduce VOC emissions from 68 points by 13,605 tpy. Therefore, Colorado's Ozone SIP already includes RACT provisions for storage tanks controls adequate to address the Oil and Gas CTG.

b. Compressors

Regulation Number 7, Section XVII. currently includes State-Only requirements for centrifugal and reciprocating compressors. These requirements do not address all of the Oil and Gas CTG's recommended RACT for reciprocating compressors at natural gas processing plants, nor are the requirements in Colorado's Ozone SIP. Therefore, the Division proposes to revise the requirements for centrifugal and reciprocating compressors to address the recommended RACT and include the revisions in Colorado's Ozone SIP.

The Oil and Gas CTG recommends that individual reciprocating compressors located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, but not at the well site, reduce VOC emissions by either replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement, or by routing rod packing emissions to a process through a closed vent system under negative pressure. The Oil and Gas CTG also recommends that individual centrifugal compressors using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, but not at the well site, reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95%. The Oil and Gas CTG recommends monitoring, recordkeeping, and reporting in order to ensure and demonstrate compliance with the recommended RACT.

Existing Regulation Number 7, Section XVII.B.3. requires that owners or operators of centrifugal compressors using wet seals reduce uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems by at least 95%, unless the compressor is subject to 40 CFR Part 60, Subpart OOOO. Existing Section XVII.B.3. also requires that owners or operators of reciprocating compressors located at natural gas compressor stations replace the rod packing every 26,000 hours of operation or every 36 months, unless the compressor is subject to 40 CFR Part 60, Subpart OOOO. Section XVII.B.3. does not require compressor monitoring, recordkeeping, or reporting. Section XVII.B.3. is not currently part of Colorado's Ozone SIP.

The Division proposes to duplicate the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. in proposed Section XII.J. in order to include the requirements in Colorado's Ozone SIP. The Division proposes to expand the reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to adress the Oil and Gas CTG recommendations. The Division proposes to allow owners or operators the option to reduce VOC emissions by routing reciprocating compressor emissions to a process and centrifugal compressor emissions to a process or control. The Division also proposes monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

c. Continuous bleed pneumatic controllers

Regulation Number 7, Section XVIII. currently includes State-Only requirements for pneumatic controllers. These requirements do not address all of the Oil and Gas CTG's recommended RACT for pneumatic controllers at natural gas processing plants, nor are the requirements in Colorado's Ozone SIP. Therefore, the Division is proposing to revise the requirements for pneumatic controllers to address the recommended RACT and include the revisions in Colorado's Ozone SIP.

The Oil and Gas CTG recommends that individual, continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant maintain a natural gas bleed rate of zero standard cubic feet per hour ("scfh"), unless there is a functional need to have a pneumatic controller with a bleed rate greater than zero. The Oil and Gas CTG also recommends that individual, 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 maintain a natural gas bleed rate less than or equal to six scfh, unless there is a functional need to have a pneumatic controller with a bleed rate greater than six. The Oil and Gas CTG recommends that owners or operators tag pneumatic controllers exceeding those standards, maintain records of the pneumatic controllers, and submit annual reports.

Existing Regulation Number 7, Section XVIII. requires continuous bleed pneumatic controllers actuated by natural gas and located at, or upstream of natural gas processing plants to have a constant bleed rate less than or equal to six scfh, unless the high-bleed pneumatic controller must remain in service due to safety or process purposes. Section XVIII. also currently requires owners or operators of high-bleed pneumatic controllers to tag the controller, perform necessary enhanced maintenance, and keep records on high-bleed pneumatic controllers. Section XVIII. is not currently part of Colorado's Ozone SIP.

The Division proposes to remove the "State-Only" designation from the DMNFR pneumatic controller requirements in Section XVIII. in order to include the requirements in Colorado's Ozone SIP. These requirements include the low-bleed standard and justification, maintenance, and records of high-bleed pneumatic controllers. The Division has not to date received any such justifications for high-bleed pneumatic controller. The Division also proposes to revise the current requirements to specify that pneumatic controllers located at natural gas processing plants in the DMNFR maintain a natural gas bleed rate of zero scfh. The Division proposes to duplicate the high-bleed provisions for owners or operators of natural gas processing plants that require a pneumatic controller with a bleed rate greater than zero, including the process to submit a justification as well as tag and maintain such devices. The provisions that apply outside the DMNFR will remain enforceable on a State-Only basis.

d. Pneumatic pumps

Regulation Number 7 does not currently include requirements for pneumatic pumps.

The Oil and Gas CTG recommends that natural gas-driven diaphragm pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG recommends that individual natural gas-driven diaphragm pumps located at well sites, which operate for any period of time on 90 days per calendar year or more, reduce natural gas emissions by 95% by routing the emissions from the pneumatic pump to an onsite control device or process. The Oil and Gas CTG also recommends monitoring, recordkeeping, and reporting requirements.

The Division proposes to include pneumatic pump emission control and associated monitoring and recordkeeping requirements in proposed Section XII.K. as part of Colorado's Ozone SIP.

e. Equipment leaks at natural gas processing plants

Colorado's Ozone SIP currently includes requirements for equipment leaks at natural gas processing plants in the DMNFR. The Division proposes to revise the requirements for equipment leaks at natural gas processing plants to address the recommended RACT.

The Oil and Gas CTG recommends that owners or operators of natural gas processing plants implement the 40 CFR Part 60, Subpart VVa level LDAR program for equipment components at the natural gas processing plant.

Existing Regulation Number 7, Section XII.G. requires that owners or operators of natural gas processing plants comply with either the LDAR program as provided at 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the natural gas processing plant, or the applicable LDAR requirements as provided at 40 CFR Part 60, Subparts OOOO or OOOOa. These provisions are already part of Colorado's Ozone SIP.

Subpart KKK requires a 40 CFR Part 60, Subpart VV level LDAR program. Subparts OOOO and OOOOa require a Subpart VVa level LDAR program. Both Subparts VV and VVa require owners or operators to inspect equipment (e.g., valves, pumps) and repair leaks above specified thresholds. The leak repair thresholds in Subpart VVa are lower than Subpart VV for pumps in light liquid service (2,000 v 10,000 ppm), valves in gas/vapor service and in light liquid service (500 v 10,000 ppm). Subpart VV also requires inspections of connectors in gas/vapor service and in light liquid service (VV does not address). Similarly, the leak repair threshold in Subparts OOOO and OOOOa are lower than Subpart KKK for pressure relief devices in gas/vapor service (500 v 10,000 ppm). Therefore, the Division proposes to revise Section XII.G. to require, at a minimum, compliance with the LDAR program in Subpart OOOO, which requires Subpart VVa level LDAR. This proposed revision is consistent with the Oil and Gas CTG recommendations.

f. Fugitive emissions at well sites and gathering and boosting stations

Regulation Number 7, Section XVII. currently includes State-Only requirements for the leak detection and repair of components at well production facilities and natural gas compressor stations. These requirements do not address all of the Oil and Gas CTG's recommendations, nor are they in Colorado's Ozone SIP. Therefore, the Division is proposing to revise the requirements for well production facilities and natural gas compressor stations to address some recommended RACT and include the revisions in Colorado's Ozone SIP.

The Oil and Gas CTG recommends that individual well sites (comparable to Colorado's term "well production facility"), with a gas to oil ratio ("GOR") greater than or equal to 300 and producing greater than 15 barrel equivalents ("BOE") per well per day on average, develop and implement a monitoring plan that includes semi-annual optical gas imaging ("OGI"), or alternatively EPA Method 21 ("Method 21"), for fugitive emissions components at the well site. The Oil and Gas CTG recommends that individual gathering and boosting stations (comparable to Colorado's term "natural gas compressor station") located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline develop and implement a monitoring plan that includes quarterly OGI or Method 21 inspections of fugitive emissions components at the gathering and boosting station. The Oil and Gas CTG recommends repair of leaks with a concentration greater than 500 ppm methane when monitoring with Method 21 and repair of leaks with any visible emissions when monitoring with OGI. The Oil and Gas CTG recommends that companies develop and implement a monitoring plan within a company-defined area that includes, but is not limited to, monitoring frequencies, technique for determining fugitive emissions, fugitive emissions detection equipment identification, procedures and timeframes for identifying and repairing components, procedures and timeframes for verifying component repairs, records, and verification of Method 21 and OGI specifications. The Oil and Gas CTG recommends that repair of leaking components be completed as soon as practicable, but no later than thirty days after detection, with limited opportunities for delay of repair. The Oil and Gas CTG recommends that leaking components be resurveyed within thirty days of repair or replacement, using OGI or Method 21. The Oil and Gas CTG also recommends recordkeeping and reporting requirements.

The existing Regulation Number 7, Section XVII.F. requires that owners or operators of natural gas compressor stations and well production facilities inspect components for leaks using an infra-red camera, Method 21, or other Division approved instrument monitoring method ("AIMM"). Unlike the Oil and Gas CTG, which, as discussed above, uses an EPA Method 21 500 ppm methane threshold for identifying leaks to be repaired, Colorado's Section XVII. LDAR program employs an EPA Method 21 500 ppm hydrocarbon threshold. To maintain consistency of the SIP and State-Only LDAR programs, the Division is proposing a related revision to Section II. to note that certain provisions of Section XII. will apply to the regulation of emissions of hydrocarbons, and not just VOCs.

Existing Section XVII.F. specifies an inspection frequency based on facility VOC emissions. Section XVII.F. requires owners or operators to make a first attempt to repair identified leaks within five days after discovery and to remonitor repaired leaks within fifteen days after repair. Section XVII.F. identifies leaks requiring repair as those exceeding a specified hydrocarbon concentration when detected with Method 21 and as any detectable emissions detected with infra-red camera. Section XVII.F. requires owners or operators to maintain LDAR records and submit an annual LDAR report. Section XVII.F. is not currently part of Colorado's Ozone SIP.

The Division proposes to duplicate the LDAR requirements from existing Section XVII.F., including key definitions from Section XVII.A., in proposed Sections XII.B. and XII.L. in order to include the requirements in Colorado's Ozone SIP. The Division proposes to increase the minimum inspection frequencies to address recommendations in the Oil and Gas CTG concerning inspection frequencies. As a result, proposed Section XII.L. will require, at a minimum, annual leak inspections at well production facilities with uncontrolled actual VOC emissions greater than one tpy and less than or equal to six tpy, semi-annual leak inspections at well production facilities with uncontrolled actual VOC emissions greater than six tpy, and quarterly inspections at natural gas compressor stations in the DMNFR. The proposed Section XII.L. retains the current repair, remonitoring, recordkeeping, and reporting provisions in Section XVII.F., with a few revisions. Among other revisions, the reports would include some additional details that the Division has determined are necessary to improve the usefulness of the reports. The Oil and Gas CTG recommends exempting well sites that produce on average less than 15 BOE per well per day from the recommended LDAR program. To address this exemption, but retain consistency with the Commission's existing programs, the Division proposes to exempt well production facilities with uncontrolled actual emissions less than one tpy from the proposed LDAR requirements in Section XII.L.

The Division also proposes to expand the existing regulation of hydrocarbon emissions in Section II. to include the regulation of hydrocarbon emissions under the proposed revisions in Section XII., which will be part of Colorado's Ozone SIP. Regulation Number 7, Section XVII.F. currently regulates hydrocarbon emissions and maintaining these hydrocarbon thresholds in the proposed Section XII. further maintains consistency between the SIP and State-Only LDAR programs.

In recognition of the highly evolving field of leak monitoring, the Division also proposes a process for the review and approval of alternative instrument based monitoring methods for inclusion in Colorado's Ozone SIP. 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 Division proposes to include an application and review process in Colorado's Ozone SIP for the potential approval of instrument based monitoring methods that are an alternative to an infra-red camera or EPA's Method 21. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative monitoring must be capable of detecting leaks comparable to the leak detection thresholds specified for an infra-red camera or EPA's Method 21 to be potentially approvable.

B. State-Only control measures for pneumatic controllers

The Division proposes State-Only revisions concerning 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 specifically recommend a pneumatic controller inspection and maintenance as RACT. Therefore the revisions are proposed as State-Only.

Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere. Colorado's 2017 emissions inventory estimated approximately 53,000 pneumatic controllers at well sites in the DMNFR, emitting approximately 7,400 tpy VOC and 15,300 tpy methane-ethane. Colorado's inventory suggests that of the 53,000 pneumatic controllers, approximately 2,500 are continuous-bleed controllers. The proposed revisions requiring pneumatic controller inspection and maintenance apply to both continuous bleed and intermittent pneumatic controllers, and obtain VOC emission reductions that will help reduce ozone in the DMNFR.

As discussed above, Regulation Number 7, Section XVIII. includes requirements for pneumatic controllers actuated by natural gas and located at, or upstream of natural gas processing plants. The Division proposes to add maintenance requirements to Section XVIII. for owners or operators of natural gas-driven pneumatic controllers in the DMNFR. The Division proposes to require owners or operators of pneumatic controllers to inspect pneumatic controllers at well production facilities and natural gas compressor stations at the same frequency as the well production facility and natural gas compressor station LDAR inspections in proposed Section XII.L. The Division proposes that owners or operators utilize these inspections to determine whether the pneumatic controllers are operating properly and to repair or conduct maintenance on pneumatic controllers that are not operating properly. The Division's proposal includes minimum recordkeeping and reporting requirements, consistent with the existing Section XVII. and proposed Section XII. LDAR programs.

C. Clarifications, support, and program alignment

The Division proposes to clarify the existing Section XII. system-wide storage tank program and glycol natural gas dehydrator semi-annual reporting provisions to replace the reference to "ozone season" with the appropriate months addressed in the November report. This revision is made in recognition that, pursuant to EPA's final rule promulgating the revised 2015 ozone standard, Colorado's ozone season is now year-round. (*See* 80 Fed. Reg. 65292 at p.65419 (Oct. 26, 2015)). There are no substantive changes proposed to the system-wide or gas dehydrator reporting programs by these revisions.

The Division proposes to clarify what leaks from components require repair in the existing State-Only Section XVII.F., and also in the proposed Section XII.L. LDAR program. This revision clarifies that all emissions from components detected with an infra-red camera or Method 21 are considered leaks, but that only those leaks exceeding the specified thresholds require repair.

The Division also proposes to clarify and set further boundaries around the time frame for repair of leaks from components. The existing Section XVII.F. requires a first attempt to repair a leak within five days of discovery but does not specify when repair must be completed. The Oil and Gas CTG recommends that repair of leaking components be completed as soon as practicable, but no later than thirty days after detection. Therefore, the Division proposes to require the completion of leak repairs within thirty days after discovery, both in existing Section XVII.F. and also in the proposed Section XII.L. The Division proposes to maintain the existing limited opportunities for delay of repair. The Division further proposes to ensure that repair delays resulting from unavailable parts that extend beyond this thirty day timeframe are limited to truly necessary delays by requiring certification by the operator that reasonable attempts have been made to secure the needed parts. The Division also proposes other limited revisions, clarifications, and details to the recordkeeping and reporting requirements of the LDAR program existing in Section XVII.F. and proposed for Section XII.L.

Lastly, the Division proposes to clarify in the existing State-Only Section XVIII.C.2. (proposed renumbering as Section XVIII.C.3.) that owners or operators must install no-bleed pneumatic controllers where the facility uses electric grid power and it is technically and economically feasible to use a no-bleed pneumatic controller. If the facility does not use electric grid power or a no-bleed pneumatic controller is not feasible, the owner or operator can then install a pneumatic controller emitting VOCs in an amount equal to or less than a low bleed pneumatic controller. This revision clarifies that the first option for an owner or operator installing a pneumatic controller at a facility using electric grid power is a no-bleed pneumatic controller and that the second option is a pneumatic controller with emissions equal to or less than a low-bleed pneumatic controller where a no-bleed pneumatic controller is not feasible.

POTENTIAL ISSUES FOR COMMISSION CONSIDERATION:

In working with stakeholder on the various aspects of this rulemaking, the Division suggests the Commission consider the following issues in preparation for the rulemaking process.

First, Colorado must act within a limited timeframe. Colorado has a SIP submittal deadline of October 27, 2018, and in order to submit these SIP revisions to EPA in 2018, the rules must undergo legislative review in the 2018 Colorado legislative session. Due to the short timeframe to address the Oil and Gas CTG, the Division anticipates that while stakeholder involvement has informed the current proposal, the rulemaking process is likely to be a dynamic and fluid process. In light of the possibility that federal requirements may change, the Division also anticipates continued discussion concerning whether to wait until the October, 2018, submittal deadline to formally submit the SIP revisions to EPA. Delaying the formal SIP submission until October would help preserve flexibility but would not delay emission reductions because any new emission control requirements would be effective after Commission adoption as state regulations.

Second, the Oil and Gas CTG provides RACT recommendations for emission sources in a moderate or higher ozone nonattainment area. However, emissions are not contained by an ozone nonattainment area boundary and some stakeholders have suggested emission control requirements should be statewide. The Division anticipates that stakeholders will continue to discuss the geographic scope of the proposed revisions.

Third, Colorado's DMNFR has yet to attain the 2008 8-hour Ozone NAAQS. Emission reductions will be obtained by the proposed revisions to Colorado's Ozone SIP, as well as the proposed State-Only revisions. Some stakeholders have suggested expanding the State-Only no-bleed pneumatic controller requirements. Other stakeholders have suggested limiting the proposed State-Only pneumatic controller inspection and maintenance requirements. The Division anticipates that stakeholders will continue to discuss the scope of these two control measures.

Fourth, the Division continues to work with stakeholders concerning the proposed revisions and anticipates continued discussion concerning, but not limited to, the proposed LDAR frequencies, well production facility applicability threshold, process to inspect and determine proper operation of pneumatic controllers, potential task force and data collection effort, and alternative AIMM.

SUMMARY:

The proposed revisions to Regulation Number 7 address EPA's Oil and Gas CTG and build on upon existing Regulation Number 7 requirements. The additional proposed revisions to Regulation Number 7 securing emission reductions will help the DMNFR attain the 8-hour ozone NAAQS.

The Division proposes to include RACT requirements for the category of sources addressed in EPA's Oil and Gas CTG in Colorado's Ozone SIP. These emission sources include centrifugal compressors using wet seals, reciprocating compressors, natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, equipment leaks at natural gas processing plants, and fugitive emission components at well production facilities and natural gas compressor stations in the DMNFR.

The Division also proposes State-Only inspection and maintenance requirements for natural gas-driven pneumatic controllers in the DMNFR.

Last, the Division proposes revisions to existing provisions in Sections XVII. and XVIII. to clarify, support, and align with proposed revisions in Section XII.

ATTACHMENTS:

1. Memorandum of Notice;
2. Proposed rule – Regulation Number 7;
3. Statement of Basis, Specific Statutory Authority, and Purpose;
4. Initial Economic Impact Analysis; and
5. CTG Comparison Table.

CONTACT:

Please contact Leah Martland, with the Air Pollution Control Division at 303-692-6269 or at leah.martland@state.co.us with any questions.

Notifications regarding ozone are sent through the Division's Ozone email list, sign up available at https://www.colorado.gov/pacific/cdphe/ozone-information.

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7/6/2017

Date

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CTG Comparison Tables

Air Quality Control Commission meeting July 20, 2017

The Division provides these summary tables to assist the Air Quality Control Commission's review of the proposed revisions to Regulation Number 7, Sections XII. and XVIII. addressing EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") recommended RACT for inclusion in Colorado's Ozone SIP. Table 1 shows the types of equipment or emissions addressed by the current version of Regulation 7 and the CTG. Table 2 summarizes the differences between the current Regulation 7 requirements and the CTG recommendations for each type of equipment or emissions.

Table 1: Applicability

	Regulation 7 (section)	CTG
Storage vessels (condensate, crude oil, intermediate hydrocarbon liquids, produced water)	Yes (XII, XVII)	Yes
Compressors – centrifugal and reciprocating	Yes (XVII)	Yes
Pneumatic controllers	Yes (XVIII)	Yes
Pneumatic pumps		Yes
Equipment leaks at natural gas processing plants	Yes (XII)	Yes
Fugitive emissions – well sites and compressor stations	Yes (XVII)	Yes
Liquids unloading	Yes (XVII)	No
Natural gas driven pneumatic controllers	Yes (XVIII)	No

Table 2: Summary of Requirements

	Regulation Number 7		CTG		CO-CTG comparison
	Control	Location	Control	Location	
	VOC/hydrocarbon		VOC		
Storage vessels (crude oil, condensate, intermediate hydrocarbon liquids, produced water)	Condensate tank/battery ≥ 2 tpy uncontrolled – systemwide 70/90% control (XII), Tank/battery ≥ 6 tpy uncontrolled – 95% control & no venting & STEM (XVII)	NAA (XII), statewide (XVII)	Single ≥ 6 tpy controlled – 95% control or maintain uncontrolled ≤ 4 tpy, no detectable emissions (AVO), monthly AVO & M21	Excluding located in distribution	R7 systemwide program achieves greater reductions than CTG, R7 threshold is lower
Centrifugal compressors (wet seal fluid degassing system)	95% control unless subject to OOOO	Statewide	95% control	Between wellhead and custody transfer to	R7 more stringent because applies to all centrifugal compressors, buts lacks MRR

	Regulation Number 7		CTG		CO-CTG comparison
	Control	Location	Control	Location	
	VOC/hydrocarbon		VOC		
				transmission/storage (except at well site)	
Reciprocating compressors	Rod packing replacement unless subject to OOOO	Statewide at compressor stations	Rod packing replacement or route to process	Between wellhead and custody transfer to transmission/storage (except at well site)	CTG more stringent because R7 only applies to reciprocating compressors at compressor stations, R7 also lacks MRR
Pneumatic controllers (gas-driven, continuous bleed)	Low bleed, no bleed where feasible and electric grid used	Statewide at/upstream of gas plants	Low bleed	Wellhead to gas plant/custody transfer to oil pipeline	Same, R7 lacks some records
Pneumatic controllers (gas-driven, continuous bleed) at natural gas processing plants			Zero bleed	Natural gas processing plant	CTG more stringent because R7 only requires no-bleed for new controllers and only where feasible, R7 lacks some records
Intermittent vent pneumatic controllers	Not covered		Not covered		CTG and R7 do not address
Pneumatic pumps (gas-driven, diaphragm)	Not covered		95% control where control/process onsite	Well site (pump operating > 90 days/yr)	CTG more stringent because R7 does not address
Pneumatic pumps (gas-driven, diaphragm) at natural gas processing plants	Not covered		Zero emissions	Natural gas processing plant	
Equipment leaks at natural gas processing plants	VV or VVa LDAR	NAA natural gas processing plant	VVa LDAR	Natural gas processing plant	CTG more stringent because R7 applies VV minimum LDAR
Fugitive emissions – well sites	Components – once, annually, quarterly, monthly AIMM (IR, M21, other)	Statewide well production facility	Components – semi-annual OGI/M21 LDAR, repair 30	Well site > 300 GOR and > 15 BOE	R7 more stringent for larger emitting facilities (evaluating smaller emitting facilities)

	Regulation Number 7		CTG		CO-CTG comparison
	Control	Location	Control	Location	
	VOC/hydrocarbon		VOC		
	LDAR, monthly AVO, repair 5 days, remonitor 15 days		days, resurvey 30 days		
Fugitive emissions – compressor stations	Components – annual, quarterly, monthly AIMM (IR, M21, other) LDAR, repair 5 days, remonitor 15 days	Statewide natural gas compressor station upstream of natural gas processing plant	Components – quarterly OGI/M21 LDAR, repair 30 days, resurvey 30 days	Gathering and boosting station between wellhead to custody transfer to transmission/storage or oil pipeline	
Liquids unloading	BMPs to minimize emissions, operator on-site	Statewide well	Not covered		R7 more stringent – CTG does not address
Natural gas driven pneumatic controllers	Leak inspection and maintenance/repair	Wellhead through natural gas processing plant	Not covered		R7 more stringent – CTG does not address

The definitions of component, well production facility, and natural gas compressor station in Regulation Number 7 are similar but differ from the definitions in the Oil and Gas CTG, provided below for comparison. The Division is proposing to use the existing definitions in Regulation Number 7.

R7 component:

- Each pump seal, flange, pressure relief device, 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

CTG fugitive emissions component:

- Any component that has the potential to emit fugitive emissions of methane or VOC at a well site or gathering and boosting station site including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to A.2(c) or (d) or section D, thief hatches or other openings on a storage vessel not subject to section A, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

R7 compressor station/well site:

- 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.
- 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.

CTG compressor station/well site:

- Gathering and boosting station means any permanent combination of one or more compressors that collects natural gas and moves the natural gas at increased pressure into gathering pipelines to the natural gas processing plant or into the pipeline. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of this section.
- Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at section I.1, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

MEMORANDUM OF NOTICE

Item Title: Regulation Number 7, Sections II., XII., XVII., XVIII.

Meeting Date: July 20, 2017

GENERAL DESCRIPTION

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, Colorado submitted 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 Air Quality Control Commission ("Commission") submitted the November SIP revisions to EPA on May 31, 2017.

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. See attached comparison tables. The Division now requests that the Commission consider proposed revisions to Regulation Number 7 to include RACT requirements for each category of sources covered by EPA's Oil and Gas CTG in Colorado's Ozone SIP. These proposed revisions duplicate existing State-Only requirements for inclusion in Colorado's Ozone SIP, propose new requirements for inclusion in Colorado's Ozone SIP, and revise and/or clarify existing SIP and State-Only provisions.

Specifically, the Division proposes to duplicate the centrifugal and reciprocating compressor emission control requirements from existing Regulation Number 7, Section XVII.B.3. in proposed Section XII.J., along with new monitoring and recordkeeping requirements. The Division also proposes to create a well production facility and natural gas compressor station leak detection and repair ("LDAR") program in proposed Section XII.L., generally consistent with the existing State-Only program in Section XVII.F. but increasing the inspection frequency for smaller well production facilities and natural gas compressor stations. The Division proposes to include new pneumatic pump emission control, monitoring, and recordkeeping requirements in proposed Section XII.K. The Division's proposal includes provisions to increase the stringency of the LDAR program for equipment leaks at natural gas processing plants in existing SIP Section XII.G. The Division proposes to incorporate some of the existing Section XVIII. State-Only requirements for natural gas actuated, continuous bleed pneumatic controllers into the SIP and to require, as part of the SIP, zero bleed pneumatic controllers at natural gas processing plants.

In addition, the Division proposes State-Only revisions that require owners or operators of natural gas-driven pneumatic controllers located at a well production facility or natural gas compressor station in the DMNFR to inspect and maintain pneumatic controllers. Current information indicates these devices are a large source of emissions and that maintenance and repair can cost-effectively reduce excess emissions. The Oil and Gas CTG does not specifically recommend pneumatic controller inspection and maintenance provisions as RACT; therefore, the Division proposes to include these requirements as State-Only revisions.

These proposed revisions satisfy Colorado's Moderate CAA requirements and obtain emission reductions necessary to help the DMNFR attain the 2008 8-hour ozone NAAQS.

Further, the Division may also make clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7, Sections II., XII. and some revisions to Section XVIII. are SIP revisions. The proposed revisions to Section XVII. and some revisions to Section XVIII. are State-Only.

WHAT IS IN THIS PACKAGE?

Attachments to this Memorandum provide details on the proposal as follows:

- Agenda Item Control Sheet;
- Proposed Regulatory Language;
- Statement of Basis, Specific Statutory Authority and Purpose;
- Initial Economic Impact Analysis; and
- CTG Comparison Table.

EXPLANATION OF THE PROPOSED RULE

The Division is proposing revisions to Regulation Number 7 to address EPA's Oil and Gas CTG that build on upon existing Regulation Number 7 requirements. The Division is also proposing additional revisions to Regulation Number 7 to secure emission reductions that will help the DMNFR attain the 8-hour ozone NAAQS.

A. Ozone SIP control measures addressing EPA's Oil and Gas CTG

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, compressors, pneumatic controllers, pneumatic pumps, equipment leaks at natural gas processing plants, and fugitive emissions in the Oil and Gas CTG. 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 emission reduction 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 EPA policies on interpreting RACT.

The Division compared the Oil and Gas CTG to existing requirements in Regulation Number 7 and is proposing revisions to the existing requirements for compressors, pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emissions at well production facilities and natural gas compressor stations to address the Oil and Gas CTG's recommendations. The Division is also proposing new requirements for pneumatic pumps to address the Oil and Gas CTG's recommendations. For a summary comparison, see the attached tables comparing the Oil and Gas CTG to Regulation Number 7.

a. Storage vessels

Colorado's Ozone SIP currently includes adequate requirements to control emissions from condensate storage tanks in the DMNFR; therefore, the Division is not proposing substantive revisions to the existing SIP Section XII. provisions concerning storage tanks.

The Oil and Gas CTG recommends that owners or operators reduce VOC emissions from individual storage vessels with the potential to emit greater than or equal to six tons per year ("tpy") VOC by 95%, or maintain storage vessel VOC emissions at less than four tpy uncontrolled actual VOC. The Oil and Gas CTG applies to storage vessels that contain crude oil, condensate, intermediate hydrocarbon liquid, or produced water in the oil and natural gas industry production, processing, and transmission and storage segments.

Regulation Number 7, Section XII. requires that owners or operators of condensate storage tanks at oil and gas exploration and production operations, natural gas compressor stations, and natural gas drip stations located upstream of a natural gas processing plant that emit greater than two tpy of actual uncontrolled VOC reduce VOC emissions from their condensate storage tank system by 90% on a weekly basis from May 1 to September 30 and by 70% on a monthly basis from October 1 to April 30 (the "system-wide" program). Section XII. defines condensate storage tank to include any tank or series of tanks that are either manifolded together or located at the same well pad. The low applicability threshold and the regulation of tank batteries instead of individual storage vessels result in the control of emissions from more tanks under Colorado's system-wide program than the Oil and Gas CTG's recommended RACT (single tank $\geq$ 6 tpy controlled emissions). Section XII. also requires the owner or operator to inspect the air pollution control equipment at least weekly, maintain records of such inspections as well as the storage tanks identification and emissions, and submit semi-annual reports of the storage tanks and emissions. These requirements are currently part of Colorado's Ozone SIP.

The Division does not propose substantive revisions to Colorado's condensate storage tank system-wide program at this time. Currently, Regulation Number 7, Section XII. applies to more storage tanks than the Oil and Gas CTG recommendation as Section XII. applies to condensate storage tanks (single or battery) with uncontrolled actual VOC emissions greater than two tpy, while the Oil and Gas CTG applies only to storage vessels (individual) with the potential to emit greater than six tpy controlled emissions. For comparison, a six tpy controlled emission standard equates to a 120 tpy uncontrolled actual emission standard. Because Colorado's existing system-wide program addresses more storage tanks than the Oil and Gas CTG, Colorado's system-wide program obtains greater VOC emission reductions than the Oil and Gas CTG's recommended RACT. To support this demonstration, the Divisions points out that in 2016 the Section XII. system-wide reports showed that 5,867 condensate tanks/batteries reduced VOC emissions by 74,221 tpy. In contrast, looking at a potential impact of the Oil and Gas CTG storage vessel program, Colorado's inventory shows that 95% control of individual condensate, crude, or produced water storage vessels with the potential to emit greater than six tpy controlled VOC (i.e., the Oil and Gas CTG applicability standard) would reduce VOC emissions from 68 points by 13,605 tpy. Therefore, Colorado's Ozone SIP already includes RACT provisions for storage tanks controls adequate to address the Oil and Gas CTG.

b. Compressors

Regulation Number 7, Section XVII. currently includes State-Only requirements for centrifugal and reciprocating compressors. These requirements do not address all of the Oil and Gas CTG's recommended RACT for reciprocating compressors at natural gas processing plants, nor are the requirements in Colorado's Ozone SIP. Therefore, the Division proposes to revise the requirements for centrifugal and reciprocating compressors to address the recommended RACT and include the revisions in Colorado's Ozone SIP.

The Oil and Gas CTG recommends that individual reciprocating compressors located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, but not at the well site, reduce VOC emissions by either replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement, or by routing rod packing emissions to a process through a closed vent system under negative pressure. The Oil and Gas CTG also recommends that individual centrifugal compressors using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, but not at the well site, reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95%. The Oil and Gas CTG recommends monitoring, recordkeeping, and reporting in order to ensure and demonstrate compliance with the recommended RACT.

Existing Regulation Number 7, Section XVII.B.3. requires that owners or operators of centrifugal compressors using wet seals reduce uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems by at least 95%, unless the compressor is subject to 40 CFR Part 60, Subpart OOOO. Existing Section XVII.B.3. also requires that owners or operators of reciprocating compressors located at natural gas compressor stations replace the rod packing every 26,000 hours of operation or every 36 months, unless the compressor is subject to 40 CFR Part 60, Subpart OOOO. Section XVII.B.3. does not require compressor monitoring, recordkeeping, or reporting. Section XVII.B.3. is not currently part of Colorado's Ozone SIP.

The Division proposes to duplicate the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. in proposed Section XII.J. in order to include the requirements in Colorado's Ozone SIP. The Division proposes to expand the reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to adress the Oil and Gas CTG recommendations. The Division proposes to allow owners or operators the option to reduce VOC emissions by routing reciprocating compressor emissions to a process and centrifugal compressor emissions to a process or control. The Division also proposes monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

c. Continuous bleed pneumatic controllers

Regulation Number 7, Section XVIII. currently includes State-Only requirements for pneumatic controllers. These requirements do not address all of the Oil and Gas CTG's recommended RACT for pneumatic controllers at natural gas processing plants, nor are the requirements in Colorado's Ozone SIP. Therefore, the Division is proposing to revise the requirements for pneumatic controllers to address the recommended RACT and include the revisions in Colorado's Ozone SIP.

The Oil and Gas CTG recommends that individual, continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant maintain a natural gas bleed rate of zero standard cubic feet per hour ("scfh"), unless there is a functional need to have a pneumatic controller with a bleed rate greater than zero. The Oil and Gas CTG also recommends that individual, 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 maintain a natural gas bleed rate less than or equal to six scfh, unless there is a functional need to have a pneumatic controller with a bleed rate greater than six. The Oil and Gas CTG recommends that owners or operators tag pneumatic controllers exceeding those standards, maintain records of the pneumatic controllers, and submit annual reports.

Existing Regulation Number 7, Section XVIII. requires continuous bleed pneumatic controllers actuated by natural gas and located at, or upstream of natural gas processing plants to have a constant bleed rate less than or equal to six scfh, unless the high-bleed pneumatic controller must remain in service due to safety or process purposes. Section XVIII. also currently requires owners or operators of high-bleed pneumatic controllers to tag the controller, perform necessary enhanced maintenance, and keep records on high-bleed pneumatic controllers. Section XVIII. is not currently part of Colorado's Ozone SIP.

The Division proposes to remove the "State-Only" designation from the DMNFR pneumatic controller requirements in Section XVIII. in order to include the requirements in Colorado's Ozone SIP. These requirements include the low-bleed standard and justification, maintenance, and records of high-bleed pneumatic controllers. The Division has not to date received any such justifications for high-bleed pneumatic controller. The Division also proposes to revise the current requirements to specify that pneumatic controllers located at natural gas processing plants in the DMNFR maintain a natural gas bleed rate of zero scfh. The Division proposes to duplicate the high-bleed provisions for owners or operators of natural gas processing plants that require a pneumatic controller with a bleed rate greater than zero, including the process to submit a justification as well as tag and maintain such devices. The provisions that apply outside the DMNFR will remain enforceable on a State-Only basis.

d. Pneumatic pumps

Regulation Number 7 does not currently include requirements for pneumatic pumps.

The Oil and Gas CTG recommends that natural gas-driven diaphragm pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG recommends that individual natural gas-driven diaphragm pumps located at well sites, which operate for any period of time on 90 days per calendar year or more, reduce natural gas emissions by 95% by routing the emissions from the pneumatic pump to an onsite control device or process. The Oil and Gas CTG also recommends monitoring, recordkeeping, and reporting requirements.

The Division proposes to include pneumatic pump emission control and associated monitoring and recordkeeping requirements in proposed Section XII.K. as part of Colorado's Ozone SIP.

e. Equipment leaks at natural gas processing plants

Colorado's Ozone SIP currently includes requirements for equipment leaks at natural gas processing plants in the DMNFR. The Division proposes to revise the requirements for equipment leaks at natural gas processing plants to address the recommended RACT.

The Oil and Gas CTG recommends that owners or operators of natural gas processing plants implement the 40 CFR Part 60, Subpart VVa level LDAR program for equipment components at the natural gas processing plant.

Existing Regulation Number 7, Section XII.G. requires that owners or operators of natural gas processing plants comply with either the LDAR program as provided at 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the natural gas processing plant, or the applicable LDAR requirements as provided at 40 CFR Part 60, Subparts OOOO or OOOOa. These provisions are already part of Colorado's Ozone SIP.

Subpart KKK requires a 40 CFR Part 60, Subpart VV level LDAR program. Subparts OOOO and OOOOa require a Subpart VVa level LDAR program. Both Subparts VV and VVa require owners or operators to inspect equipment (e.g., valves, pumps) and repair leaks above specified thresholds. The leak repair thresholds in Subpart VVa are lower than Subpart VV for pumps in light liquid service (2,000 v 10,000 ppm), valves in gas/vapor service and in light liquid service (500 v 10,000 ppm). Subpart VV also requires inspections of connectors in gas/vapor service and in light liquid service (VV does not address). Similarly, the leak repair threshold in Subparts OOOO and OOOOa are lower than Subpart KKK for pressure relief devices in gas/vapor service (500 v 10,000 ppm). Therefore, the Division proposes to revise Section XII.G. to require, at a minimum, compliance with the LDAR program in Subpart OOOO, which requires Subpart VVa level LDAR. This proposed revision is consistent with the Oil and Gas CTG recommendations.

f. Fugitive emissions at well sites and gathering and boosting stations

Regulation Number 7, Section XVII. currently includes State-Only requirements for the leak detection and repair of components at well production facilities and natural gas compressor stations. These requirements do not address all of the Oil and Gas CTG's recommendations, nor are they in Colorado's Ozone SIP. Therefore, the Division is proposing to revise the requirements for well production facilities and natural gas compressor stations to address some recommended RACT and include the revisions in Colorado's Ozone SIP.

The Oil and Gas CTG recommends that individual well sites (comparable to Colorado's term "well production facility"), with a gas to oil ratio ("GOR") greater than or equal to 300 and producing greater than 15 barrel equivalents ("BOE") per well per day on average, develop and implement a monitoring plan that includes semi-annual optical gas imaging ("OGI"), or alternatively EPA Method 21 ("Method 21"), for fugitive emissions components at the well site. The Oil and Gas CTG recommends that individual gathering and boosting stations (comparable to Colorado's term "natural gas compressor station") located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline develop and implement a monitoring plan that includes quarterly OGI or Method 21 inspections of fugitive emissions components at the gathering and boosting station. The Oil and Gas CTG recommends repair of leaks with a concentration greater than 500 ppm methane when monitoring with Method 21 and repair of leaks with any visible emissions when monitoring with OGI. The Oil and Gas CTG recommends that companies develop and implement a monitoring plan within a company-defined area that includes, but is not limited to, monitoring frequencies, technique for determining fugitive emissions, fugitive emissions detection equipment identification, procedures and timeframes for identifying and repairing components, procedures and timeframes for verifying component repairs, records, and verification of Method 21 and OGI specifications. The Oil and Gas CTG recommends that repair of leaking components be completed as soon as practicable, but no later than thirty days after detection, with limited opportunities for delay of repair. The Oil and Gas CTG recommends that leaking components be resurveyed within thirty days of repair or replacement, using OGI or Method 21. The Oil and Gas CTG also recommends recordkeeping and reporting requirements.

The existing Regulation Number 7, Section XVII.F. requires that owners or operators of natural gas compressor stations and well production facilities inspect components for leaks using an infra-red camera, Method 21, or other Division approved instrument monitoring method ("AIMM"). Unlike the Oil and Gas CTG, which, as discussed above, uses an EPA Method 21 500 ppm methane threshold for identifying leaks to be repaired, Colorado's Section XVII. LDAR program employs an EPA Method 21 500 ppm hydrocarbon threshold. To maintain consistency of the SIP and State-Only LDAR programs, the Division is proposing a related revision to Section II. to note that certain provisions of Section XII. will apply to the regulation of emissions of hydrocarbons, and not just VOCs.

Existing Section XVII.F. specifies an inspection frequency based on facility VOC emissions. Section XVII.F. requires owners or operators to make a first attempt to repair identified leaks within five days after discovery and to remonitor repaired leaks within fifteen days after repair. Section XVII.F. identifies leaks requiring repair as those exceeding a specified hydrocarbon concentration when detected with Method 21 and as any detectable emissions detected with infra-red camera. Section XVII.F. requires owners or operators to maintain LDAR records and submit an annual LDAR report. Section XVII.F. is not currently part of Colorado's Ozone SIP.

The Division proposes to duplicate the LDAR requirements from existing Section XVII.F., including key definitions from Section XVII.A., in proposed Sections XII.B. and XII.L. in order to include the requirements in Colorado's Ozone SIP. The Division proposes to increase the minimum inspection frequencies to address recommendations in the Oil and Gas CTG concerning inspection frequencies. As a result, proposed Section XII.L. will require, at a minimum, annual leak inspections at well production facilities with uncontrolled actual VOC emissions greater than one tpy and less than or equal to six tpy, semi-annual leak inspections at well production facilities with uncontrolled actual VOC emissions greater than six tpy, and quarterly inspections at natural gas compressor stations in the DMNFR. The proposed Section XII.L. retains the current repair, remonitoring, recordkeeping, and reporting provisions in Section XVII.F., with a few revisions. Among other revisions, the reports would include some additional details that the Division has determined are necessary to improve the usefulness of the reports. The Oil and Gas CTG recommends exempting well sites that produce on average less than 15 BOE per well per day from the recommended LDAR program. To address this exemption, but retain consistency with the Commission's existing programs, the Division proposes to exempt well production facilities with uncontrolled actual emissions less than one tpy from the proposed LDAR requirements in Section XII.L.

The Division also proposes to expand the existing regulation of hydrocarbon emissions in Section II. to include the regulation of hydrocarbon emissions under the proposed revisions in Section XII., which will be part of Colorado's Ozone SIP. Regulation Number 7, Section XVII.F. currently regulates hydrocarbon emissions and maintaining these hydrocarbon thresholds in the proposed Section XII. further maintains consistency between the SIP and State-Only LDAR programs.

In recognition of the highly evolving field of leak monitoring, the Division also proposes a process for the review and approval of alternative instrument based monitoring methods for inclusion in Colorado's Ozone SIP. 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 Division proposes to include an application and review process in Colorado's Ozone SIP for the potential approval of instrument based monitoring methods that are an alternative to an infra-red camera or EPA's Method 21. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative monitoring must be capable of detecting leaks comparable to the leak detection thresholds specified for an infra-red camera or EPA's Method 21 to be potentially approvable.

B. State-Only control measures for pneumatic controllers

The Division proposes State-Only revisions concerning 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 specifically recommend a pneumatic controller inspection and maintenance as RACT. Therefore the revisions are proposed as State-Only.

Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere. Colorado's 2017 emissions inventory estimated approximately 53,000 pneumatic controllers at well sites in the DMNFR, emitting approximately 7,400 tpy VOC and 15,300 tpy methane-ethane. Colorado's inventory suggests that of the 53,000 pneumatic controllers, approximately 2,500 are continuous-bleed controllers. The proposed revisions requiring pneumatic controller inspection and maintenance apply to both continuous bleed and intermittent pneumatic controllers, and obtain VOC emission reductions that will help reduce ozone in the DMNFR.

As discussed above, Regulation Number 7, Section XVIII. includes requirements for pneumatic controllers actuated by natural gas and located at, or upstream of natural gas processing plants. The Division proposes to add maintenance requirements to Section XVIII. for owners or operators of natural gas-driven pneumatic controllers in the DMNFR. The Division proposes to require owners or operators of pneumatic controllers to inspect pneumatic controllers at well production facilities and natural gas compressor stations at the same frequency as the well production facility and natural gas compressor station LDAR inspections in proposed Section XII.L. The Division proposes that owners or operators utilize these inspections to determine whether the pneumatic controllers are operating properly and to repair or conduct maintenance on pneumatic controllers that are not operating properly. The Division's proposal includes minimum recordkeeping and reporting requirements, consistent with the existing Section XVII. and proposed Section XII. LDAR programs.

C. Clarifications, support, and program alignment

The Division proposes to clarify the existing Section XII. system-wide storage tank program and glycol natural gas dehydrator semi-annual reporting provisions to replace the reference to “ozone season” with the appropriate months addressed in the November report. This revision is made in recognition that, pursuant to EPA’s final rule promulgating the revised 2015 ozone standard, Colorado’s ozone season is now year-round. (*See* 80 Fed. Reg. 65292 at p.65419 (Oct. 26, 2015)). There are no substantive changes proposed to the system-wide or gas dehydrator reporting programs by these revisions.

The Division proposes to clarify what leaks from components require repair in the existing State-Only Section XVII.F., and also in the proposed Section XII.L. LDAR program. This revision clarifies that all emissions from components detected with an infra-red camera or Method 21 are considered leaks, but that only those leaks exceeding the specified thresholds require repair.

The Division also proposes to clarify and set further boundaries around the time frame for repair of leaks from components. The existing Section XVII.F. requires a first attempt to repair a leak within five days of discovery but does not specify when repair must be completed. The Oil and Gas CTG recommends that repair of leaking components be completed as soon as practicable, but no later than thirty days after detection. Therefore, the Division proposes to require the completion of leak repairs within thirty days after discovery, both in existing Section XVII.F. and also in the proposed Section XII.L. The Division proposes to maintain the existing limited opportunities for delay of repair. The Division further proposes to ensure that repair delays resulting from unavailable parts that extend beyond this thirty day timeframe are limited to truly necessary delays by requiring certification by the operator that reasonable attempts have been made to secure the needed parts. The Division also proposes other limited revisions, clarifications, and details to the recordkeeping and reporting requirements of the LDAR program existing in Section XVII.F. and proposed for Section XII.L.

Lastly, the Division proposes to clarify in the existing State-Only Section XVIII.C.2. (proposed renumbering as Section XVIII.C.3.) that owners or operators must install no-bleed pneumatic controllers where the facility uses electric grid power and it is technically and economically feasible to use a no-bleed pneumatic controller. If the facility does not use electric grid power or a no-bleed pneumatic controller is not feasible, the owner or operator can then install a pneumatic controller emitting VOCs in an amount equal to or less than a low bleed pneumatic controller. This revision clarifies that the first option for an owner or operator installing a pneumatic controller at a facility using electric grid power is a no-bleed pneumatic controller and that the second option is a pneumatic controller with emissions equal to or less than a low-bleed pneumatic controller where a no-bleed pneumatic controller is not feasible.

MATERIALS CONTAINED IN THE PROPOSED RULE

The redline-strikeout version of the proposed revisions to Regulation Number 7 is attached.

PUBLIC MEETINGS

Beginning in January, 2017, the Division held numerous meetings with stakeholders to discuss the scope of a rulemaking to address the Oil and Gas CTG, as well as consider other potential emission reduction measures in the oil and gas sector. Stakeholder meeting attendees included representatives from industry, consultants, government agencies, EPA, environmental groups, monitoring technology manufacturers, and the general public.

The Commission will meet with Commission staff as necessary to fully understand the development, impact, and effect of these rule revisions.

BACKGROUND ON THE DEVELOPMENT OF THE RULEMAKING PROPOSAL

What is the problem?

The CAA requires Colorado to submit a SIP revision addressing the CAA's Moderate nonattainment area requirements, which include provisions implementing RACT for sources subject to EPA's CTGs for VOC source categories. EPA published final notice of the Oil and Gas CTG October 27, 2016, therefore provisions implementing RACT for this VOC source category were not included in the SIP revisions adopted by the Air Quality Control Commission ("Commission") in November, 2016. EPA established an October 27, 2018, deadline for states to submit SIP revisions addressing the Oil and Gas CTG.

In addition, Colorado has yet to attain the 2008 ozone NAAQS and additional emission reductions are necessary to decrease ozone in the DMNFR.

How does this proposed rule help solve the problem?

The proposed revisions concerning compressors, pneumatic pumps, continuous bleed pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emission components at well production facilities and natural gas compressor stations satisfy Colorado's CAA obligation to revise Colorado's SIP to include provisions implementing RACT for oil and gas VOC source categories addressed by the Oil and Gas CTG that are consistent with the CAA and EPA policies on interpreting RACT.

Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere. The Division estimates that there are 53,000 pneumatic controllers at well sites in the DMNFR emitting approximately 7,400 tpy VOC and 15,300 tpy methane-ethane. The proposed revisions requiring natural gas-driven pneumatic controller inspection and maintenance obtain VOC emission reductions that will help reduce ozone in the DMNFR.

How was the rule developed?

The Oil and Gas CTG was noticed and discussed at the federal level.

The Division met with oil and gas stakeholders to discuss the proposed revisions. Input from the Regional Air Quality Council, Division staff, EPA, and all sectors helped to craft the proposed revisions.

What is the fiscal and economic impact of the proposed rule?

The fiscal and economic impacts of the proposed rule are further detailed in the initial Economic Impact Analysis.

How does the rule compare to federal requirements or adjacent state requirements?

Federal requirements:

The CAA does not dictate the specific terms of the RACT SIP revisions being proposed by the Division. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Federal law also requires states with Moderate ozone nonattainment areas to include RACT in the SIP for each category of VOC sources covered by a CTG issued prior to the date of attainment. EPA issued the Oil and Gas CTG in October, 2016, that recommended RACT for storage vessels, centrifugal compressors, reciprocating compressors, pneumatic pumps, pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emission components at well sites and gathering and boosting stations. SIP revisions addressing the Oil and Gas CTG are due to EPA by October 27, 2018.

The Division proposes to adopt revisions to Regulation Number 7 that satisfy Colorado's Moderate nonattainment area RACT obligations and implement RACT for oil and gas emission sources covered by EPA's Oil and Gas CTG.

Facilities or equipment in the oil and natural gas sector may also be subject to federal NESHAP at 40 CFR Part 63, Subparts HH and HHH and NSPS at 40 CFR Part 60, Subparts Kb, KKK, OOOO, or OOOOa.

<u>Other State (Arizona, New Mexico, Utah) requirements:</u>

Parts of Arizona were designated as serious for the 1979 1-hour ozone NAAQS and marginal for the 1997 8-hour ozone NAAQS. Arizona is currently classified as a maintenance ozone area under these NAAQS. Parts of Arizona were designated as marginal nonattainment for the 2008 ozone NAAQS and recently reclassified as Moderate nonattainment for the 2008 ozone NAAQS. Arizona completed a Moderate ozone SIP in December, 2016, which stated that "oil and natural gas production – fugitive emissions" sources were not present in the nonattainment area. Arizona has adopted NSPS Kb, NSPS KKK, NSPS OOOO, NESHAP HH, and NESHAP HHH as of June 28, 2013. The duties of the Arizona Oil and Gas Conservation Commission (e.g., well drilling and well completions) were transferred to the Arizona Department of Environmental Quality in 2016.

Parts of Utah were designated as moderate nonattainment for the 1997 1-hour ozone NAAQS. Utah is currently classified as a maintenance ozone area under this NAAQS and, therefore, is not required to address EPA's Oil and Gas CTG. Utah has adopted NSPS KKK, NSPS OOOO, NESHAP HH, and NESHAP HHH as of July 1, 2014. Utah's Department of Environmental Quality regulates natural gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants. Specifically, Utah's Department of Environmental Quality requires existing pneumatic controllers to meet standards established for new equipment in NSPS OOOO, the use of auto-igniters on flares, and bottom or submerged filling for the transfer of intermediate hydrocarbon liquid or produced water. Utah's Division of Natural Resources Oil and Gas Program regulates well drilling and well completions. Utah's Department of Environmental Quality requires self-igniters on flares.

Parts of New Mexico were designated as marginal nonattainment for the 1997 1-hour ozone NAAQS. Marginal nonattainment areas are not required to conduct a moderate nonattainment area level RACT analysis. New Mexico is currently classified as a maintenance ozone area under this NAAQS and, therefore, is not required to address EPA's Oil and Gas CTG. New Mexico has adopted NSPS Kb, NSPS KKK, NSPS OOOO, NSPS OOOOa, NESHAP HH, and NESHAP HHH as of September 15, 2015. The New Mexico Oil Conservation Division regulates well drilling and production.

<u>How will the rule be implemented?</u>

The amended rules will be published on the Commission's website, and emailed to subscribers to the Division's General Air Division Updates email list. Division staff will be informed of the revisions to ensure the changes will be reflected in applicable permitting and regulatory actions. Any necessary guidance will be developed and shared with stakeholders.

<u>Are there time constraints?</u>

There are time constraints on the regulated community of the proposed revisions concerning compressors, pneumatic pumps, continuous bleed pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emission components at well sites and compressor stations as subject sources will have to conduct inspections and compile records.

There are time constraints on the development and submission of this SIP. EPA has established an October 27, 2018, submission deadline for SIP revisions addressing EPA's Oil and Gas CTG. Colorado's legislature, meeting January through May, 2018, must review the SIP before the Commission can submit the SIP to EPA. Therefore, the revisions to Regulation Number 7 to incorporate provisions implementing RACT for the oil and gas industry into Colorado's Ozone SIP must be completed before the 2018 legislative session.

What if the Air Quality Control Commission does not adopt the proposed rule?

If the Commission declines to adopt the proposal, the potential emission reductions achievable under the proposed requirements for reciprocating compressors, pneumatic pumps, continuous bleed pneumatic controllers at natural gas processing plants, equipment leaks at natural gas processing plants, and fugitive emission components at well production facilities and natural gas compressor stations are unlikely to occur. In addition, Colorado will be unable to submit this portion of its 2008 Ozone RACT SIP, which if not corrected could potentially lead to a federal implementation plan and sanctions on highway funding.

Range of Regulatory Alternatives

The Commission could choose to adopt the proposal in full, adopt only certain elements of the proposal, adopt different elements, or not adopt the proposal at all.

However, Colorado must submit SIP revisions to EPA implementing RACT for the oil and gas VOC source categories addressed by and comparable to the Oil and Gas CTG by October 27, 2018. Colorado must also attain the 2008 ozone NAAQS by July 20, 2018.

The proposed revisions were selected to address the Oil and Gas CTG recommendations, while still preserving Colorado's existing oil and gas regulatory program. This approach was selected to achieve additional emission reductions, improve the likelihood of EPA approval of this portion of Colorado's RACT SIP, and acknowledge Colorado's leading role in the oil and gas regulatory sector.

Concerning the proposed pneumatic controller inspection and maintenance provisions, the Commission could adopt the provisions as a permanent program, include a sunset provision, or include a direction to reassess the program after a limited time of implementation.

Contact for more information:

Please contact Leah Martland with the Air Pollution Control Division at 303-692-6269 or at leah.martland@state.co.us with any questions.

ECONOMIC IMPACT ANALYSIS
(Initial Analysis)

Item Title: Regulation Number 7, Sections II., XII., XVII., XVIII.

Meeting Date: July 20, 2017

ISSUE

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, Colorado submitted 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 Air Quality Control Commission ("Commission") submitted the November SIP revisions to EPA on May 31, 2017.

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. See attached comparison table. The Division now requests that the Commission consider proposed revisions to Regulation Number 7 to include RACT requirements for each category of sources covered by EPA's Oil and Gas CTG in Colorado's Ozone SIP. These proposed revisions duplicate existing State-Only requirements for inclusion in Colorado's Ozone SIP, propose new requirements for inclusion in Colorado's Ozone SIP, and revise and/or clarify existing SIP and State-Only provisions.

Specifically, the Division proposes to duplicate the centrifugal and reciprocating compressor emission control requirements from existing Regulation Number 7, Section XVII.B.3. in proposed Section XII.J., along with new monitoring and recordkeeping requirements. The Division also proposes to create a well production facility and natural gas compressor station leak detection and repair ("LDAR") program in proposed Section XII.L., generally consistent with the existing State-Only program in Section XVII.F. but increasing the inspection frequency for smaller well production facilities and natural gas compressor stations. The Division proposes to include new pneumatic pump emission control, monitoring, and recordkeeping requirements in proposed Section XII.K. The Division's proposal includes provisions to increase the stringency of the LDAR program for equipment leaks at natural gas processing plants in existing SIP Section XII.G. The Division proposes to incorporate some of the existing Section XVIII. State-Only requirements for natural gas actuated, continuous bleed pneumatic controllers into the SIP and to require, as part of the SIP, zero bleed pneumatic controllers at natural gas processing plants.

In addition, the Division proposes State-Only revisions that require owners or operators of natural gas-driven pneumatic controllers located at a well production facility or natural gas compressor station in the DMNFR to inspect and maintain pneumatic controllers. Current information indicates these devices are a large source of emissions and that maintenance and repair can cost-effectively reduce excess emissions. The Oil and Gas CTG does not specifically recommend pneumatic controller inspection and maintenance provisions as RACT; therefore, the Division proposes to include these requirements as State-Only revisions.

These proposed revisions satisfy Colorado's Moderate CAA requirements and obtain emission reductions necessary to help the DMNFR attain the 2008 8-hour ozone NAAQS.

Further, the Division may also make clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7, Sections II., XII. and some revisions to Section XVIII. are SIP revisions. The proposed revisions to Section XVII. and some revisions to Section XVIII. are State-Only.

REQUIREMENTS FOR ECONOMIC IMPACT ANALYSIS ("EIA")

Section 25-7-110.5(4)(a), C.R.S. sets forth the requirements for the initial and final Economic Impact Analysis, as stated below:

> Before any permanent rule is proposed pursuant to this section, an initial economic impact analysis shall be conducted in compliance with this subsection (4) of the proposed rule or alternative proposed rules. Such economic impact analysis shall be in writing, developed by the proponent, or the Division in cooperation with the proponent and made available to the public at the time any request for hearing on a proposed rule is heard by the commission. A final economic impact analysis shall be in writing and delivered to the technical secretary and to all parties of record five working days prior to the prehearing conference. If no prehearing conference is scheduled, the economic impact analysis shall be submitted at least ten working days before the date of the rule-making hearing. The proponent of an alternative proposal will provide, in conjunction with the Division, a final economic impact analysis five working days prior to the prehearing conference. The economic impact analyses shall be based upon reasonably available data. Except where data is not reasonably available, or as otherwise provided in this section, the failure to provide an economic impact analysis of any noticed proposed rule or any alternative proposed rule will preclude such proposed rule or alternative proposed rule from being considered by the Commission. Nothing in this section shall be construed to restrict the Commission's authority to consider alternative proposals and alternative economic impact analyses that have not been submitted prior to the prehearing conference for good cause and so long as parties have adequate time to review them.

Per Section 25-7-110.5(2), C.R.S., the requirements of Section 25-7-110.5(4) shall not apply to rules which: (1) adopt by reference applicable federal rules; (2) adopt rules to implement prescriptive state statutory requirements where the AQCC is allowed no significant policy-making options; or, (3) adopt rules that have no regulatory impact on any person, facility or activity.

DISCUSSION

To satisfy Colorado's Moderate nonattainment area CAA obligations to revise Colorado's SIP to include provisions that implement RACT for every VOC source category covered by a CTG, the Division is proposing to include RACT requirements for existing and new centrifugal compressors, reciprocating compressors, pneumatic pumps, pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emissions at well production facilities and natural gas compressor stations in the DMNFR in Colorado's Ozone SIP. Where possible, the proposed revisions build upon existing Regulation Number 7 requirements.

There may be minimal economic impacts of the proposed revisions for owners or operators of centrifugal compressors, reciprocating compressors, and continuous bleed pneumatic controllers in the DMNFR as the proposed revisions include additional monitoring and/or recordkeeping requirements than are currently required under State-Only provisions. The State-Only provisions currently require the emission control measures proposed for inclusion in Colorado's Ozone SIP.

There may be economic impacts of the proposed revisions for owners or operators of reciprocating compressors at natural gas processing plants in the DMNFR as the proposed revisions require owners or operators replace reciprocating compressor rod packing or route emissions to a process. Similarly, there may be economic impacts of the proposed revisions for owners or operators of natural gas-driven, continuous bleed pneumatic controllers at natural gas processing plants in the DMNFR as the proposed revisions require zero bleed pneumatic controllers. These proposed revisions also include recordkeeping and potential monitoring requirements. The current State-Only requirements do not apply to reciprocating compressors at natural gas processing plants and only require low-bleed pneumatic controllers at natural gas processing plants.

There may be economic impacts of the proposed revisions for owners or operators of natural gas processing plants in the DMNFR as the proposed revisions revise the LDAR program minimum from a Subpart VV level program to a Subpart VVa level program, which increases the repair threshold stringency for some equipment. Colorado's Ozone SIP currently requires a Subpart VV level program for existing natural gas processing plants in the DMNFR.

There may be economic impacts of the proposed revisions for owners or operators of pneumatic pumps at well production facilities and natural gas processing plants in the DMNFR as the proposed revisions require 95% control of natural gas emissions or establish a zero emission standard. The proposed revisions also include monitoring and recordkeeping requirements. Regulation Number 7 does not currently include any requirements for pneumatic pumps.

There may be economic impacts of the proposed revisions for owners or operators of well production facilities and natural gas compressor stations in the DMNFR as the proposed revisions increase the frequency of the LDAR inspections. The proposed revisions also add additional detail to the recordkeeping and reporting requirements than are currently required under State-Only provisions. The State-Only provisions currently specify different inspection frequencies than those proposed for inclusion in Colorado's Ozone SIP.

Lastly, there may be economic impacts of the proposed revisions for owners or operators of natural gas actuated pneumatic controllers located at or upstream of a natural gas processing plant in the DMNFR as the proposed revisions require owners or operators to inspect and maintain pneumatic controllers. The proposed revisions also include recordkeeping and reporting requirements. Regulation Number 7 does not currently include inspection and maintenance requirements for all pneumatic controllers.

The degree of potential impact of the proposed revisions may be site specific and depend on the owner or operator's current required, or voluntary, control, monitoring, and recordkeeping program for the existing pieces of equipment. The impacts of the proposed revisions for new pieces of equipment or facilities can be more readily accounted for prior to installation or construction, but are also unknown. The Division relies on cost data supporting the Oil and Gas

CTG in addition to cost data the Division has independently collected. Some stakeholders have raised concerns with the Oil and Gas CTG cost data. In response to these concerns and to more generally support its proposals, the Division has requested that industry provide cost information concerning the impacts of the proposed revisions.

Based on the data the Division has at this time, the Division provides the following information to satisfy the economic analysis relating to the above described oil and gas industry emission sources, as a result of the proposed revisions to Regulation Number 7:

(A) Identification of the industrial and business sectors that will be impacted by the proposal;
(B) Quantification of the direct cost to the primary affected business or industrial sector; and
(C) Incorporation of an estimate of the economic impact of the proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors.

Section 25-7-110.5(4)(c)(III), C.R.S.

(A) Identification of the industrial and business sectors that will be impacted by the proposal

Oil and gas industry owners and operators of the following existing and new emission sources in the DMNFR may be impacted by the proposed revisions:

- Centrifugal compressors using wet seals and located after the well production facility and before the point of custody to the natural gas transmission and storage segment;
- Reciprocating compressors located after the well production facility and before the point of custody to the natural gas transmission and storage segment;
- Natural gas-driven diaphragm pneumatic pumps located at a well production facility or natural gas processing plant;
- Continuous bleed natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant;
- Equipment within a process unit located at an onshore natural gas processing plant;
- Fugitive emission components at a well production facility or natural gas compressor station; and
- Natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant.

(B) Quantification of the direct cost to the primary affected business or industrial sector

Below is a summary table of the cost analyses of the proposed revisions.

Summary Table: Total Cost of Proposed Regulation					
Description (# in DMNFR)	Item	# of Affected Facilities	Net Total Costs	VOC Reduction [tpy]	VOC Control Cost [$/ton]
Natural Gas Processing Plants (16)	Centrifugal compressor emission control, monitoring, and recordkeeping	?	Minimal	NA	NA
	Reciprocating compressor rod packing replacements,	133	Minimal to $4,280 / compressor	12.8	$334

Summary Table: Total Cost of Proposed Regulation					
Description (# in DMNFR)	Item	# of Affected Facilities	Net Total Costs	VOC Reduction [tpy]	VOC Control Cost [$/ton]
	monitoring, and recordkeeping				
	Pneumatic pump retrofit, monitoring, and recordkeeping	?	Minimal to $72,394 / pump	0.96	?
	Pneumatic controller retrofit, monitoring, and recordkeeping	?	$0 - $2,000 / controller	Up to 33	$6 - $68 / controller
	LDAR inspections at NSPS VVa (NSPS OOOO) level	16	$8,499 / facility	2.9	$2,844
Natural Gas Compressor Stations (73)	Centrifugal compressor emission control, monitoring, and recordkeeping	?	Minimal	NA	NA
	Reciprocating compressor rod packing replacements, monitoring, and recordkeeping	?	Minimal	NA	NA
	Pneumatic controller retrofit to low bleed, monitoring, and recordkeeping	?	Minimal	NA	NA
	LDAR inspections, repair, reporting, and recordkeeping	53	$253,560	111	$2,284
	(State Only) Pneumatic controller inspections, reporting, and recordkeeping	?	$0-$500	?	?
Well Production Facilities (7,264)	Pneumatic pumps emissions controls, monitoring, and recordkeeping	230	$5,433/pump	6.4	$847
	Pneumatic controller retrofit to low bleed and recordkeeping	2,500	Minimal	NA	NA
	LDAR inspections at annual frequency, repair, recordkeeping, and reporting	2,958	$3,457,319	5,324	$649
	LDAR inspections at semi-annual frequency, repair, recordkeeping, and reporting	1,370	$1,274,256	658	$1,860
	(State Only) Pneumatic controller inspections, recordkeeping, and reporting	53,000	$0-$500	?	?

Centrifugal and reciprocating compressors (Section XII.J.)

The Oil and Gas CTG recommends emission control requirements for reciprocating compressors and centrifugal compressors using wet seals and located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, excluding the well site. Regulation Number 7, Section XVII.B.3. includes similar control requirements. However, Section XVII.B.3. is not part of Colorado's ozone SIP. Therefore, the proposed revisions duplicate the emission control requirements from Section XVII.B.3. in Section XII. to include the requirements in Colorado's ozone SIP, and add minimal monitoring and recordkeeping requirements to ensure and demonstrate compliance with the emission control requirements.

There are no additional costs related to including the compressor emission control requirements for reciprocating compressors at natural gas compressor stations or centrifugal compressors in Colorado's Ozone SIP because these requirements are already required as a State-Only provision. There may be costs related to the proposed monitoring and recordkeeping requirements as owners or operators may have to conduct cover and closed vent system inspections, document such inspections, or track and document compressor operating hours. However, the Division believes that these costs are minimal as owners or operators will be able to incorporate the monitoring and recordkeeping requirements into their existing monitoring and recordkeeping programs. In addition, some compressors may already be subject to similar requirements under 40 CFR Part 60, Subparts OOOO or OOOOa and will be able to demonstrate compliance with the proposed monitoring and recordkeeping requirements by complying with the monitoring and recordkeeping requirements in Subparts OOOO or OOOOa, instead of complying with duplicative requirements in Regulation Number 7.

There may be additional costs of the proposed requirement for owners or operators of reciprocating compressors at natural gas processing plants to replace the rod packing or route emissions to a process. The Division estimates that there are sixteen natural gas processing plants in the ozone nonattainment area, with an estimated 133 engines. Conservatively assuming these 133 engines existing at the natural gas processing plants are all reciprocating engines and would be subject to the proposed requirements, it is unknown how many owners or operators voluntarily replace rod packing or capture engine emissions and therefore would not have to implement a new emission control program. However, the Oil and Gas CTG estimates the capital cost of replacing the rod packing at $4,280 and the cost per ton of VOC reduced at $334, without factoring in the natural gas savings. Concerning the option to route VOC emissions to a process, the Oil and Gas CTG assumed that costs would be minimal for an owner or operator to route emissions to an existing vapor recovery unit. In addition, there may be minimal costs related to the proposed monitoring and recordkeeping requirements, as discussed above, where an owner or operator is not currently monitoring and keeping compressor records.

Pneumatic pumps (Section XII.K.)

The Oil and Gas CTG recommends emission control requirements for natural gas-driven diaphragm pumps located at well sites and natural gas processing plants. Regulation Number 7 does not include requirements for pneumatic pumps. Therefore, the proposed revisions include an emission control requirement for pneumatic pumps at well production facilities, an emission standard for pneumatic pumps at natural gas processing plants, and associated monitoring and recordkeeping.

There may be costs of the proposed requirement for owners or operators to control emissions from pneumatic pumps at well production facilities. The Division estimates that there are approximately 7,264 well production facilities in the DMNFR and the 2017 ozone emissions inventory estimated approximately 230 pneumatic pumps at well sites. However, the Division does not have data as to what type of pneumatic pumps were reported (e.g., diaphragm or plunger/piston) and whether the facility has an existing control device onsite. The Oil and Gas CTG estimates the capital cost for routing emissions to an existing control device at $5,433, with a cost per ton of VOC reduced at $847, without gas savings.

There may be costs of the proposed requirement for owners or operators to ensure that pneumatic pumps at natural gas processing plants have an emission rate of zero. The Division estimates that there are sixteen natural gas processing plants in the ozone nonattainment area, but does not have the data as to the quantity of natural gas-driven diaphragm pumps at the natural gas processing plants. Similarly, EPA did not have data to characterize the number and types of gas-driven pumps at natural gas processing plants. EPA estimated in the 2016 NSPS OOOOa Technical Support Document ("TSD") emissions and costs for small to large model natural gas processing plants, ranging from 4 to 100 total pumps at 25 to 75% pump distribution scenarios. The 2016 NSPS OOOOa TSD estimates annual costs to replace compressors in an existing instrument air system in order to increase capacity to operate the pumps from $10,051 to $72,394. EPA also assumes in the Oil and Gas CTG that existing natural gas processing plants have an instrument air system in place and the cost of increasing the air load on the system would be associated with the incremental cost of connecting the pneumatic pumps to the existing system. The Oil and Gas CTG utilizes the above described cost estimates from the 2016 NSPS OOOOa TSD and estimates VOC reductions from converting a pneumatic pump to instrument air at 0.96 tpy per pump. In addition, the Oil and Gas CTG estimates the capital cost for a solar-powered electric pump at $2,227 and the value of the natural gas saved per diaphragm pump at $786 per year. The Oil and Gas CTG also estimates the cost of an electric pump at $4,647, annualized costs at $954, and the value of the natural gas saved per diaphragm pump at $786 per year.

There may also be costs related to the proposed monitoring and recordkeeping requirements as owners or operators may have to conduct and document control system inspections and keep records related to pneumatic pumps. However, the Division believes that these costs are minimal as owners or operators will be able to rely upon their existing monitoring and recordkeeping programs to incorporate the proposed monitoring and recordkeeping requirements. In addition, some pneumatic pumps may already be subject to similar requirements under 40 CFR Part 60, Subpart OOOOa and will be able to demonstrate compliance with the proposed requirements by complying with Subpart OOOOa.

Continuous bleed pneumatic controllers (Sections XVIII.C. through E.)

The Oil and Gas CTG recommends emission control requirements for continuous bleed, natural gas-driven pneumatic controllers located from the wellhead through the natural gas processing plant. Regulation Number 7, Section XVIII. currently requires low-bleed pneumatic controllers at or upstream of natural gas processing plants. Section XVIII. is not part of Colorado's Ozone SIP. Therefore, the proposed revisions remove "State-Only" designations from the pneumatic controller requirements applicable in the DMNFR to include the requirements in Colorado's Ozone SIP. The proposed revisions also require that pneumatic controllers at natural gas processing plants maintain a natural gas bleed rate of zero, which is consistent with the Oil and Gas CTG recommendations.

There are no additional costs related to including the low-bleed requirement for pneumatic controllers located from the wellhead to a natural gas processing plant in Colorado's Ozone SIP because this requirement is already required as a State-Only provision.

There may be costs related to the proposed requirement for owners or operators of natural gas processing plants to ensure that natural gas-driven pneumatic controllers have a bleed rate of zero. The Division estimates that there are sixteen natural gas processing plants in the ozone nonattainment area, but does not have data on the quantity of natural gas actuated pneumatic controllers at the natural gas processing plants. The Oil and Gas CTG assumes that existing natural gas processing plants have already replaced pneumatic controllers with other types of control, such as an instrument air system, and any pneumatic controllers with a bleed rate greater than zero are required due to safety reasons. Therefore, the Division believes the cost to owners or operators of natural gas processing plants of the proposed requirements are minimal and limited to documenting, tagging, and maintaining any natural gas actuated pneumatic controllers with a bleed rate greater than zero that are required for safety and/or process purposes. Should an owner or operator of a natural gas processing plant convert an existing natural gas actuated pneumatic controller to their instrument air system, the Oil and Gas CTG estimates a capital cost of converting the pneumatic controller at $2,000 and the cost per ton of VOC reduced between $6 and $68 per pneumatic controller.

There may also be costs related to the proposed recordkeeping requirements as owners or operators may have to compile and retain documentation concerning their continuous bleed pneumatic controllers. For example, the Division estimates that there are approximately 7,264 well production facilities in the DMNFR with approximately 2,500 natural gas-driven low-bleed pneumatic controllers. Under the proposed revisions, owners or operators of these low-bleed pneumatic controllers will have to keep records documenting that the pneumatic controller is low-bleed. In addition, owners or operators of natural gas-driven, continuous bleed pneumatic controllers at natural gas processing plants will have to keep records demonstrating that the pneumatic controller has a bleed rate of zero or justifying a bleed rate greater than zero. However, the Division believes that owners or operators will be able to incorporate the recordkeeping requirements into their existing recordkeeping programs with minimal cost. There are no additional costs related to records of high-bleed pneumatic controllers because records are already required as a State-Only provision. Further, no high-bleed pneumatic controllers have been reported to the Division under the State-Only provisions.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Oil and Gas CTG recommends a minimum LDAR program equivalent to 40 CFR Part 60, Subpart VVa for existing and new natural gas processing plants. Natural gas processing plants in the DMNFR are currently required to comply with, at a minimum, the equipment LDAR program in 40 CFR Part 60, Subpart KKK. Subpart KKK relies on the LDAR program in 40 CFR Part 60, Subpart VV. In contrast, 40 CFR Part 60, Subparts OOOO and OOOOa rely on the LDAR program in Subpart VVa. Therefore, the proposed revisions replace the reference to Subpart KKK with Subpart OOOO. Requiring owners or operators of natural gas processing plants to comply with, at a minimum, the equipment LDAR program in Subpart OOOO lowers the leak detection thresholds for pumps in light liquid service, valves in gas/vapor service and in light liquid service, connectors in gas/vapor service and in light liquid service, and pressure relief devices in gas/vapor service, as compared to Subpart KKK.

The Division estimates that there are sixteen natural gas processing plants in the DMNFR. Of these, six are subject to the Subpart KKK LDAR program, five are subject to the Subpart OOOO LDAR program, one is subject to the Subpart OOOOa LDAR program, and four are subject to both the Subparts KKK and OOOO LDAR programs for different equipment. Therefore, only six natural gas processing plants will have full conversions to a Subpart OOOO LDAR program, and only four natural gas processing plants will have partial conversions.

Compliance with the Subpart OOOO LDAR program will require the owners or operators of the natural gas processing plants subject, wholly or in part, to the Subpart KKK LDAR program to repair pumps in light liquid service, valves in gas/vapor service and in light liquid service, connectors in gas/vapor service and in light liquid service, and pressure relief devices in gas/vapor service at a lower leak detection threshold. The proposed revisions, therefore, may result in additional repair or equipment replacement costs for such facilities. However, the proposed revisions will also result in additional emission reductions, and product savings, due to a potential increase in the repair of leaks. The Oil and Gas CTG estimated that the incremental capital cost of implementing a Subpart VVa (Subpart OOOO) level LDAR program from a baseline Subpart VV (Subpart KKK) LDAR program was $8,499 per natural gas processing plant. The Oil and Gas CTG also estimated that the cost per ton of VOC reduced was $2,844, and $2,810 after including natural gas savings. These estimates were made for a model natural gas processing plant wholly subject to a Subpart VV (Subpart KKK) level LDAR program. The Oil and Gas CTG model natural gas processing plant included 1,392 valves, 4,392 connectors, 134 open-ended lines, and 29 pressure relief valves. The Division assumes costs will be less for the owner or operator of four natural gas processing plants because they are already partially subject to the Subpart VVa (Subpart OOOO) LDAR program.

The Division requests that owners or operators of natural gas processing plants in the DMNFR provide Colorado specific cost information concerning the proposed revisions.

Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)

The Oil and Gas CTG recommends a LDAR program to reduce fugitive emissions from components at well sites and gathering and boosting stations located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline. Regulation Number 7, Section XVII.F. currently requires owners or operators of well production facilities and natural gas compressor stations that are located downstream of a natural gas processing plant inspect components for leaks and repair detected leaks. Section XVII.F. is not part of Colorado's ozone SIP. In addition, the Oil and Gas CTG recommends a fixed inspection frequency using optical gas imaging ("OGI") or EPA Method 21. In contrast, Section XVII.F. includes a tiered inspection frequency using infra-red camera or Method 21 ("approved instrument monitoring method' or "AIMM") based on facility emissions and a fixed inspection frequency using AVO for well production facilities. The proposed revisions duplicate provisions from Section XVII.F. in proposed Section XII. to include the requirements in Colorado's ozone SIP and build on Colorado's existing LDAR framework by replacing the tiered AIMM inspection frequency with a fixed inspection frequency.

The Division estimates, based on Air Pollution Emission Notice ("APEN") reported data, that there are 7,264 well production facilities in the DMNFR, with an estimated 4,328 (1 tpy to ≤ 12 tpy facilities) potentially impacted by the proposed increase in inspection frequency. Of the 4,328 potentially impacted well production facilities, an estimated 2,958 have uncontrolled actual VOC emissions greater than one ton per year ("tpy") but less than or equal to six tpy, and an estimated 1,370 have emissions greater than six tpy but less than or equal to 12 tpy. The Division estimates that there are 72 natural gas compressor stations in the DMNFR and 53 (≤ 12 tpy facilities) potentially impacted by the proposed increase in inspection frequency.

The Division proposes to revise the inspection frequencies for natural gas compressor stations as set forth in Table A.

Table A: Proposed Leak Inspection Frequencies Leak at Compressor Stations

Component Leak Uncontrolled Actual VOC Emissions	Current Inspection Frequency	Proposed Inspection Frequency
≤ 12 tpy	Annually	Quarterly
>12 tpy to ≤ 50 tpy	Quarterly	No Change
> 50 tpy*	Monthly	No Change

**There are currently no compressor stations in Colorado with calculated leaks at this level*

The Division proposes to revise the inspection frequencies for well production facilities as shown in Table B.[1]

Table B: Proposed Leak Inspection Frequencies for Well Production Facilities		
Tank Uncontrolled Actual VOC Emissions	Current Inspection Frequency	Proposed Inspection Frequency
≥ 1 tpy ≤ 6 tpy	One Time (and Monthly AVO)	Annual
> 6 tpy to ≤ 12 tpy	Annually	Semi-Annual
>12 tpy to ≤ 50 tpy	Quarterly	No Change
> 50 tpy	Monthly	No Change

The Division's analysis only addresses natural gas compressor stations and well production facilities with component leak uncontrolled actual VOC emissions and tank uncontrolled actual VOC emissions, respectively, less than or equal to 12 tpy. The Division's proposed revisions to the inspection frequencies do not affect facilities with emissions greater than 12 tpy as these facilities are currently required to conduct more frequent inspections on a State-Only basis.

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed LDAR requirements.

First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.[2] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, recordkeeping, and reporting. Based on the assumptions set forth in Table C below, the total annual cost for each inspector will be $202,536, which equates to an hourly inspection rate of $108.

Table C: Leak Detection and Repair (LDAR) Inspector - Annualized Cost Analysis[3]			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$127,612		
FLIR Camera Maintenance/Repair		$7,845	
Photo Ionization Detector	$5,230		
Vehicle (4x4 Truck)	$23,012		
Inspection Staff		$78,450	
Supervision (@ 20%)		$15,690	
Overhead (@10%)		$7,845	
Travel (@15%)		$11,768	
Recordkeeping (@10%)		$7,845	
Reporting (@10%)		$7,845	
Fringe (@30%)		$23,535.0	
Subtotal Costs	$155,854		
Annualized Costs*	$41,714	$160,823	$202,536

[1] Because there may be a limited number of instances where well production facilities do not have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this EIA, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

[2] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

[3] Costs are based on the purchasing power of the US Dollar in May 2017

Table C: Leak Detection and Repair (LDAR) Inspector - Annualized Cost Analysis[3]			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
**over 5 years at 6% ROR*		Annualized Hourly Rate	$108
		Annualized Hourly Rate + 30% Profit	$140

Because some operators will choose to utilize contractors for LDAR inspections, the Division assumed an additional 30% profit margin for all inspections to render a conservative estimate of $140 per hour for inspection costs.

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at natural gas compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. Consistent with existing requirements under Regulation Number 7, the proposed revisions also allow owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool followed by a Method 21 inspection to identify potential leaking components. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.[4]

For natural gas compressor stations, the Division used reported component counts for natural gas compressor stations within each leak rate category shown in Table A above. Based on these counts and the inspection times per component discussed above, the Division calculated that the total time to conduct an IR camera inspection of a natural gas compressor station with component leak uncontrolled actual VOC emissions less than or equal to 12 tpy would be 10.6 hours.

Table D: Calculated Inspection Time Compressor Station Leak Inspections		
Component Leak Uncontrolled Actual VOC Emissions in NAA	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	21.2 hours	10.6 hours

The Division has limited data on the number of components per well production facility. Based on the limited available data, there appears to be a distinction between component numbers at well production facilities in the DMNFR and well production facilities outside the DMNFR. Accordingly, the Division calculated inspection times based on the data available for well production facilities in the DMNFR, as shown in Table E below, because the Division's proposed revisions do not affect well production facilities outside of the DMNFR. The Division calculated that the time to conduct an IR camera inspection of a well production facility in the DMNFR with tank uncontrolled actual VOC emissions between 1 and 12 tpy would be 6.1 hours.

Table E: Calculated Inspection Times for Well Production Facility Leak Inspections		
Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
DMNFR	12.2 hours	6.1 hours

Next, the Division calculated the projected inspection costs for both natural gas compressor stations and well production facilities. The Division used industry reported emission data to determine the number of facilities that will be subject to the proposed quarterly (for natural

[4] Based on the Division's own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

gas compressor stations) or annual or semi-annual (for well production facilities) inspection frequencies, and multiplied those inspections by the calculated inspection time and projected hourly inspection rate. For natural gas compressor stations and well production facilities, the Division assumed that all inspections would be conducted by third-party contractors in an effort to make a conservative cost estimate.

The Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a $76.78 hourly rate to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the type of component and the complexity of the repair.[5] To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking component rate for facilities subject to annual inspections, 1.48% leaking component rate for facilities subject to semi-annual inspections and a 1.77% leaking component rate for facilities subject to quarterly inspections.[6] To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to one thousand cubic feet (MCF) of natural gas, assuming a price of $3.59/MCF. With respect to re-monitoring, the Division determined that additional costs associated with re-monitoring are negligible because re-monitoring can be undertaken at the same time as repair.

For natural gas compressor stations ≤ 12 tpy, the existing Regulation Number 7 requires an annual inspection. The proposed revisions increase the inspection frequency to quarterly. Thus, to properly account for the increased inspection frequency and associated costs, the Division analyzed the incremental change related to the revised inspection frequency. Based on the above methodology, the annual inspection cost for natural gas compressor stations is set forth in Table F below.

Table F: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Inspection Costs (@ $140/hr) Using IR Camera/Method 21 Hybrid

Regulatory Scenario	Number of Compressor Stations in DMNFR	Annual Inspection Frequency	Time per IR Camera Inspection [hours]	Total Annual Inspection Time [hours]	Total Annual Inspection Cost
Existing Reg.	53	1	10.6	561.8	$78,652
Proposed Reg.	53	4	10.6	2,247.2	$314,608
Incremental Change		3		1,685.4	$235,956

Repair costs associated with these inspections are shown in Table G and fuel savings associated with these repairs are shown in Table H.

[5] See "Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards," Bradley Nelson and Heather Brown, April 17, 2012; "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011. Hourly repair cost is adjusted for inflation to May 2017.

[6] This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry's Proposed Revisions to Colorado's Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits.

Table G: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Repair Costs					
Regulatory Scenario	Number of Compressor Stations in DMNFR	Leak Repair Rate [$/hr]	Number of Leaks per Compressor Station	Total Leak Repair Time per CS [hours]	Total Annual Repair Cost
Existing Reg.	53	$76.78	30.1	23.0	$93,595
Proposed Reg.	53	$76.78	45.1	34.6	$140,799
Incremental Change			15.0	11.6	$47,204

Table H: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Recovered Natural Gas Value from Leak Repairs					
Regulatory Scenario	Number of Compressor Stations in DMNFR	Total Recovered Natural Gas per CS [tons/year]	Value of Natural Gas [$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
Existing Reg.	53	10.2	$3.59	35.8	$58,060
Proposed Reg.	53	15.4	$3.59	35.8	$87,660
Incremental Change		5.2			$29,600

The total net costs for natural gas compressor station LDAR are set forth in Table I. The incremental increase is the estimated cost associated with revising the inspection frequency from annual to quarterly.

Table I: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Net Leak Inspection and Repair Costs					
Regulatory Scenario	Number of Compressor Stations in DMNFR	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
Existing Reg.	53	$78,652	$93,595	-$58,060	$114,187
Proposed Reg.	53	$314,608	$140,799	-$87,660	$367,747
Incremental Increase		$235,956	$47,204	-$29,600	$253,560

Finally, the Division calculated the cost effectiveness of the proposed LDAR requirements based on the costs identified above and the projected emission reductions. To determine emission reductions, the Division first calculated VOC and methane emissions, assuming no inspections and based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% emissions reduction for annual inspections, a 50% reduction for semi-annual inspections, and a 60% reduction for quarterly inspections.

Using this information, the Division calculated the total emission reductions and the incremental emissions reductions from leaks at natural gas compressor stations in the non-attainment area as shown below in Table J.

Table J: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Inspection Emission Reductions						
Regulatory Scenario	Number of Comp Stations	LDAR Program Reduction %	VOC Emissions Reduction for each	Total VOC Reduction [tpy]	Methane-Ethane Emissions Reduction	Total Methane-Ethane

	in DMNFR		CS tier [tpy]		for each CS [tpy]	Reduction [tpy]
Existing Reg.	53	40%	4.0	212	6.2	329
Proposed Reg.	53	60%	6.1	323	9.3	493
Incremental Emissions Reduction				111		164

Based on the proposed increase in the inspection frequency at natural gas compressor stations, there are additional or "incremental" emission reductions shown in Table J above. By increasing the frequency of leak inspections at natural gas compressor stations with emissions less than or equal to 12 tpy to quarterly, the estimated incremental cost effectiveness is $2,284/ton of VOC reduced, as shown in Table K.

Table K: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Inspection Cost Effectiveness using IR Camera/Method 21

Regulatory Scenario	LDAR Program Reduction %	Total Net Annual Inspection & Repair Cost	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [$/ton]
Existing Reg.	40%	$114,187	212	$539	329	$347
Proposed Reg.	60%	$367,747	323	$1,139	493	$746
Incremental cost effectiveness of additional emission reductions		$253,560	111	$2,284	164	$1,546

Using the same multi-step process for well production facilities with storage tank uncontrolled actual VOC emissions between 1 and 12 tpy, the estimated annual inspection costs are set forth in Tables L –Q below. The incremental change is the estimated cost associated with revising the inspection frequency from one-time to annual (for ≥ 1 tpy ≤ 6 tpy tanks) and annual to semi-annual (for > 6 tpy < 12 tpy tanks).

Table L: Well Production Facility Leak Inspection Costs (@ $140/hr) Using IR Camera/Method 21 Hybrid

Regulatory Scenario	Number of Facilities in DMNFR	Annual Inspection Frequency	Total Number of Inspections	Inspection Time Per Inspection [hours]	Total Annual Inspection Cost
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy					
Existing Reg.	2,958	one-time inspection satisfied in 2015			
Proposed Reg.	2,958	1	2,958	6.1	$2,526,132
Incremental Change		1	2,958		$2,526,132
Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy					
Existing Reg.	1,370	1	1,370	8,857	$1,169,980
Proposed Reg.	1,370	2	2,740	16,714	$2,339,960
Incremental Change		1	1,370	8,857	$1,169,980

Table M: Well Production Facility Leak Repair Costs

Regulatory Scenario	Number of Facilities in DMNFR	Leak Repair Rate [$/hr]	Number of Leaks per Tank	Total Leak Repair Time per Tank [hours]	Total Annual Repair Cost
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy					
Existing Reg.	2,958	one-time inspection satisfied in 2015			
Proposed Reg.	2,958	$76.78	17	11.8	$2,679,960
Incremental Change			17	11.8	$2,679,960
Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy					
Existing Reg.	1,370	$76.78	17.0	11.8	$1,241,225
Proposed Reg.	1,370	$76.78	21.3	14.8	$1,556,791
Incremental Change			4.3	3.0	$315,566

Table N: Well Production Facility Recovered Natural Gas Value from Leak Repairs					
Regulatory Scenario	Number of Facilities in DMNFR	Total Recovered Natural Gas per tank [tons/year]	Value of Natural Gas [$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy					
Existing Reg.	2,958	one-time inspection satisfied in 2015			
Proposed Reg.	2,958	4.6	$3.59	35.8	$1,748,773
Incremental Change		4.6			$1,748,773
Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy					
Existing Reg.	1,370	4.6	$3.59	35.8	$809,946
Proposed Reg.	1,370	5.8	$3.59	35.8	$1,021,236
Incremental Change		1.2			$211,290

Table O: Well Production Facility -Net Leak Inspection and Repair Costs					
Regulatory Scenario	Number of Well Production Facilities in DMNFR	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy					
Existing Reg.	2,958	one-time inspection satisfied in 2015			
Proposed Reg.	2,958	$2,526,132	$2,679,960	-$1,748,773	$3,457,319
Incremental Increase		$2,526,132	$2,679,960	-$1,748,773	$3,457,319
Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy					
Existing Reg.	1,370	$1,169,980	$1,241,225	-$809,946	$1,601,259
Proposed Reg.	1,370	$2,339,960	$1,556,791	-$1,021,236	$2,875,515
Incremental Increase		$1,169,980	$315,566	-$211,290	$1,274,256

The incremental increase provides the estimated costs associated with changing the inspection frequency from one-time to annual (for ≥ 1 tpy ≤ 6 tpy tanks) and annual to semi-annual (for > 6 tpy < 12 tpy tanks).

Table P: Well Production Facility Leak Inspection Emission Reductions

Regulatory Scenario	Number of Facilities in DMNFR	LDAR Program Reduction %	VOC Emissions Reduction for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Methane-Ethane Emissions Reduction for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy						
Existing Reg.	2,958	one-time inspection satisfied in 2015				
Proposed Reg.	2,958	40%	1.8	5,324	2.8	8,282
Incremental Emissions Reduction			1.8	5,324	2.8	8,282
Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy						
Existing Reg.	1,370	40%	1.8	2,466	2.8	3,836
Proposed Reg.	1,370	50%	2.3	3,151	3.5	4,795
Incremental Emissions Reduction			0.5	685	0.7	959

Based on the emission reductions in Table P, the estimated cost effectiveness of annual (for ≥ 1 tpy ≤ 6 tpy tanks) and semi-annual (for ≥ 6 tpy < 12 tpy tanks) leak inspections at well production facilities with storage tank uncontrolled actual VOC emissions between 1 and 12 tpy is shown in Table Q.

Table Q: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21

Regulatory Scenario	Number of Facilities in NAA	Total Net Annual Leak Inspection & Repair Cost	Total VOC Red. [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Red. [tpy]	Methane-Ethane Control Cost [$/ton]
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy						
Existing Reg.	2,958	one-time inspection satisfied in 2015				
Proposed Reg.	2,958	$3,457,319	5,324	$649	8,282	$417
Incremental cost effectiveness of additional emission reductions		$3,457,319	5,324	$649	8,282	$417
Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy						
Existing Reg.	1,370	$1,601,259	2,466	$649	3,836	$417
Proposed Reg.	1,370	$2,875,515	3,151	$913	4,795	$600
Incremental cost effectiveness of additional emission reductions		$1,274,256	685	$1,860	959	$1,329
Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 12 tpy						
Overall incremental cost effectiveness of additional emission reductions	4,328	$4,731,575	6,009	$787	9,241	$512

The Division calculated the incremental cost effectiveness by subtracting the costs and effectiveness of the existing regulation from the proposed regulation. For well productions facilities with uncontrolled actual VOC ≥ 1 tpy ≤ 6 tpy, the cost effectiveness of the proposed revisions is estimated to be $649/ton of VOC reduced. For well production facilities with uncontrolled actual VOC > 6 tpy ≤ 12 tpy, the incremental cost effectiveness of increasing the inspection frequency to semi-annual is estimated to be $1,860/ton of VOC reduced. The overall incremental cost effectiveness of the proposed revisions for well production facilities with VOC emissions between 1 and 12 tpy is $787/ton of VOC reduced.

Similar to the analysis above, the Oil and Gas CTG estimated costs for preparing an OGI emission monitoring and repair plan for a company-defined area that included labor, reading of the rule, development of a fugitive emission monitoring plan, initial activities planning, semi-annual or quarterly monitoring, notifications, a Method 21 device, subsequent activities, OGI monitoring, repair, resurvey, and annual reports. The Oil and Gas CTG estimated the total capital cost at $17,620 per company defined area for semi-annual monitoring and $801 per well assuming 22 well sites within a company defined area, with a cost per ton VOC reduced ranging $2,494 to $11,503 without natural gas savings and depending on the type of well site. The Oil and Gas CTG estimated the total capital cost of $16,753 per facility and $2,393 per gathering and boosting station assuming 7 stations within a 210 mile radius, with a cost per ton VOC reduced at $3,205 without natural gas savings.

The Oil and Gas CTG also estimated annual repair costs at $299 for well sites and $3,436 for gathering and boosting stations per survey, assuming that 1.18% of components leak and 75% are repaired online and 25% are repaired offline. The Oil and Gas CTG estimated average fugitive emission component counts for a natural gas well site model plant at 139 valves, 510 connectors, 15 open-ended lines, and 7 pressure relief valves. The Oil and Gas CTG estimates average fugitive emission component counts for an oil well site model plant $\geq$ 300 GOR at 68 valves, 54 flanges, 186 connectors, 2 open-ended lines, and 4 pressure relief valves. The Oil and Gas CTG estimates average fugitive emission component counts for a production gathering and boosting station model plant at 906 valves, 2,864 connectors, 83 open-ended lines, and 48 pressure relief valves.

Lastly, the Oil and Gas CTG estimated the capital cost of a semi-annual EPA Method 21 emission monitoring repair plan at a 500 ppm repair threshold at $1,460 per well, with a cost per ton VOC reduced ranging $3,392 to $15,648 without natural gas savings depending on the type of well site. The Oil and Gas CTG estimated the capital cost of a quarterly monitoring program at $4,679 per gathering and boosting station, with a cost per ton VOC reduced at $4,004 without natural gas savings.

Pneumatic controllers (Section XVIII.F.)

The proposed revisions require owners or operators of existing and new natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant to operate and maintain pneumatic controllers consistent with good engineering practices. The proposed revisions also require owners or operators of existing and new natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations to inspect and determine whether the pneumatic controller is operating properly. The owner or operator would screen the pneumatic controllers with an infra-red camera or EPA's Method 21, and further inspect pneumatic controllers where emissions were observed to determine whether the pneumatic controller is operating properly. If the pneumatic controller is operating properly, no further action is required of the owner or operator. However, if an owner or operator found that a pneumatic controller was not operating properly, the proposed revisions require the owner or operator to take actions to return the device to proper operation. The proposed revisions also require the owner or operator to document and report pneumatic controller inspection and maintenance activities. 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 the revisions are proposed as State-Only.

The Division estimates that there are 7,264 well production facilities and 73 natural gas compressor stations in the DMNFR. The Division also estimates that there are approximately 53,000 natural gas-driven pneumatic controllers at well production facilities in the DMNFR. Under the proposed revisions, owners or operators of the well production facilities would inspect pneumatic controllers annually or semi-annually for proper operation, depending on the VOC emissions of the well production facility. Similarly, owners or operators of natural gas compressor stations would inspect pneumatic controllers quarterly for proper operation. The proposed revisions build upon the LDAR program in Regulation Number 7 and the Division assumes that owners or operators would incorporate the pneumatic controller inspections into their well production facility and natural gas compressor station LDAR program. Therefore, the Division believes that the inspection and recordkeeping costs are likely minimal. The Oil and Gas CTG estimates for the well site and gathering and boosting station LDAR program a resurvey cost assuming five minutes per leak at $57.80 per hour at well sites and the preparation of an annual report to take one person 4 hours at a cost of $231.

There may also be costs related to activities necessary to return a pneumatic controller to proper operation. Because methods to maintain a pneumatic controller are highly variable, costs are also variable based on labor, time, and repair or replacement parts. The mean time between first and subsequent device failures depends on the quality and composition of the gas stream, temperature variation, and rate of actuation. Pneumatic controller repair kits can range from $10 to $125, and repair time from 15 minutes to 1 hour per pneumatic controller. Some repairs may require well shut-in and incur additional costs.

However, there are likely cost savings related to maintaining and repairing pneumatic controllers due to product savings. Tuning pneumatic controllers and using the proper process settings will help maintain optimal conditions and reduce emissions. The Oil and Gas CTG notes that emissions from natural gas-driven pneumatic controllers in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device. The Oil and Gas CTG provides examples of factors increasing emissions such as nozzle corrosion, broken or worn diaphragms and fittings, improper installation, lack of maintenance, lack of calibration, debris on the vent or supply pilot, and wear in the seal seat. However, the Oil and Gas CTG concluded that maintenance of pneumatic controllers, such as cleaning and tuning, repairing leaking gaskets and seals, and eliminating unnecessary valve positions can save 5 to 18 scfh per device. Similarly, the 2016 NSPS OOOOa TSD notes that pneumatic controllers in poor condition typically bleed 5 to 10 scfh more than representative conditions due to work seals or gaskets, nozzle corrosion or wear, or lose control tube fittings. The 2016 NSPS OOOOa TSD also notes that enhanced maintenance to repair and maintain pneumatic devices can reduce emissions but that methods and costs are variable. EPA's Natural Gas Star Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry (2006) also estimates that the maintenance of natural gas-driven pneumatic controllers can save 45 to 260 mcf/year of natural gas, with implementation costs described as negligible to $500. Specifically, costs to reduce gas bleed are estimated for reducing supply pressure at $207, repairing leaks and retuning at $31, changing level controller gain settings at $0, and removing unnecessary positioners as $0. EPA estimates the payback period for cost associated with these activities ranges from immediate to three months.

The Division requests that owners or operators of natural gas-driven pneumatic controllers in the DMNFR provide Colorado specific cost information concerning the proposed revisions.

(C) Incorporation of an estimate of the economic impact of the proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors

The proposed revisions may result in positive economic impacts to supporting business that contractually conduct leak inspections, repair activities, and reporting services as some owners and operators may choose to contract a company to conduct the proposed inspection and reporting requirements. The proposed revisions may also result in positive economic impacts to equipment suppliers as some owners and operators may have to replace equipment in order to comply with the proposed revisions. It is difficult to quantify these economic impacts because the extent to which consultants assist with inspections, reporting, and analyses is unknown.

The Division requests that supporting business and industry provide Colorado specific cost information concerning the proposed revisions.

SUMMARY AND CONCLUSION

The Division prepared this Initial Economic Impact Analysis in accordance with the requirements of Section 25-7-110.594), C.R.S. Specifically, the Division utilized the methodology identified in Section 25-7-110.5(4)(c)(III), C.R.S.

The Division has determined that there may be costs related to the proposed monitoring and recordkeeping requirements for centrifugal compressors, reciprocating compressors, and continuous bleed pneumatic controllers. Because the proposed revisions build upon existing requirements, the Division believes these costs are likely minimal.

There may be economic impacts of the proposed inspection frequency or leak threshold increases for the LDAR programs at well production facilities, natural gas compressor stations, and natural gas processing plants. The proposed requirements building upon existing requirements, and the Division requests owners or operators of these facilities provide Colorado specific cost information concerning the impacts of the proposed revisions.

Lastly, there may be economic impacts of the proposed pneumatic pump, natural gas processing plant reciprocating compressor, natural gas processing plant pneumatic controller, and pneumatic controller inspection and maintenance requirements as these would be new requirements for this equipment.

Based on the above analyses, the Division believes the proposed revisions are cost-effective. The Division has provided an estimate of costs based on reasonably available information and will consider any additional information provided by stakeholders. The Division requests that affected industry or any interested party submit information with regard to the cost of compliance with these proposed rule revisions.

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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II. General Provisions

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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.

~~(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 XII.K. and L., XVII., and XVIII. The regulation of hydrocarbon emissions in Sections XVII. and XVIII. marked by (State Only) is not federally enforceable.

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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 ~~5~~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, 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. shall 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 XII.H.

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

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

XII.A.5. Well production facilities with uncontrolled actual volatile organic compound emissions greater than one (1) ton per year and natural gas compressor stations that collect, store, or handle hydrocarbon liquids are also 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, XII.J., and XII.K.

XII.A.~~5~~7. The requirements of ~~this s~~Sections XII.~~A~~ B. through XII.I. shall 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 shall, 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 this Section XII applies.

XII.B.2. "Air Pollution Control Equipment", as used in this 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 device or method 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.~~3~~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.~~4~~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.~~5~~6. “Calendar Week” shall mean a week beginning with Sunday and ending with Saturday.

XII.B.~~6~~7. “Condensate Storage Tank” shall mean 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 storage tank thief hatches), 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.~~7~~12. “Downtime” shall mean the period of time when a well is producing and the air pollution control equipment is not in operation.

XII.B.~~8~~13. “Existing” shall mean any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.

XII.B.~~9~~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.~~10~~16. “Modified or Modification” shall mean 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 contractor 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.~~11~~20. "New" shall mean 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.~~1~~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.~~1~~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.~~1~~24. "System-Wide" when used to refer to emissions and emission reductions in Section XII.D., shall mean 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 shall be 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, 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. 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 below. 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, 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 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 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 below. The dates and requisite reductions are as follows:

XII.D.2.a.(i) For the period May 1 through September 30, 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 XII.D.2.a.(viii) - 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. 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~~r~~ 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~~n~~ 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. 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 ~~during the preceding ozone season~~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. above 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 owned or operated by the same person do not exceed 30 tons per year in the 8-hour Ozone Control Area.

XII.G. ~~Gas~~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., and XVI.

XII.G.1. For fugitive VOC emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart ~~KKK~~ OOOO (July 1, 2017~~6~~) shall apply, regardless of the date of construction of the affected facility, unless subject to ~~applicable~~ the LDAR program ~~as~~ provided at 40 CFR Part 60, Subpart~~s~~ ~~OOOO or~~ OOOOa (July 1, 2017~~6~~).

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. ~~Existing n~~Natural gas processing plants within the 8-hour Ozone Control Area ~~shall~~ constructed before January 1, 2018, must begin complying with the requirements of this Section XII.G. beginning January 1, 2018 ~~by May 1, 2005~~. (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., XII.G., and XVI., shall 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 subsection.

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. shall 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.G. shall 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 this Section XII.~~G~~I. at which a glycol natural gas dehydrator and/or natural gas-fired stationary or portable engine is operated shall be subject to Sections XII.H. and/or XVI.

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 after the well production facility and before the point of custody transfer to the natural gas transmission and storage segment must be reduced by at least 95%.

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 designed and operated to route all gases, vapors, and fumes to a 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.

XII.J.1.d. The owner or operator must conduct annual EPA Method 21 inspections to determine whether a potential leak interface operates with volatile organic compound emissions less than 500 ppm.

XII.J.1.e. In the event that a leak or defect is detected, the owner or operator must repair the leak or defect as soon as practicable. First attempt to repair must be made no later than five (5) days after detecting the defect or leak and completed no later than fifteen (15) days after finding 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. Repair must be completed by the end of the next scheduled shutdown.

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

XII.J.1.f.(iii) The cover or closed vent system is difficult to inspect because inspecting personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect 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.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 maintenance or repair activities;

XII.J.1.h.(i)(C) Each cover and closed vent system inspection and any resulting maintenance or repair activities; and

XII.J.1.h.(i)(D) Each cover or closed vent system on the delay of inspection or repair list 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.-f. and XII.J.1.h.(i)(C)-(D), the owner or operator may inspect, repair, and document the cover and closed 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 requirements described in Sections XII.J.1.a.-i., the owner or operator may comply with wet seal centrifugal compressors 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 any reciprocating compressor located after the well production facility and before 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.

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) Replace the rod packing prior to January 1, 2021.

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 volatile organic compound emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions through a closed vent system designed and operated to route all gases, vapors, and fumes 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.

XII.J.2.b.(ii) The owner or operator must conduct annual EPA Method 21 inspections to determine whether a potential leak interface operates with volatile organic compound emissions less than 500 ppm.

XII.J.2.b.(iii) In the event that a leak or defect is detected, the owner or operator must repair the leak or defect as soon as practicable. First attempt to repair must be made no later than five (5) days after detecting the defect or leak and completed no later than fifteen (15) days after finding 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. Repair must be completed by the end of the next scheduled shutdown.

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

XII.J.2.b.(iv)(C) The cover or closed vent system is difficult to inspect because inspecting personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect 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.(v) 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.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, whichever is later, 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 combustion device visible emissions inspection and any resulting maintenance or repair activities;

XII.J.2.c.(i)(E) Each cover and closed vent system inspection and any resulting maintenance or repair activities; and

XII.J.2.c.(i)(F) Each cover or closed vent system on the delay of inspection or repair list 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.(i)-(iv). and XII.J.2.c.(i)(E)-(F), the owner or operator may inspect, repair, and document the cover and closed 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 requirements described in Sections XII.J.2.a.-d., the owner or operator may comply with reciprocating compressor 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 natural gas emissions from the pneumatic pump by 95% if a control device is installed at the well production facility or the owner or operator has the ability to route natural gas emissions to a process. 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 the owner or operator does not have the ability to route the emissions to a process, the owner or operator must still route the pneumatic pump emissions to the existing control device.

XII.K.2.b. 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 is shown to be technically infeasible.

XII.K.2.c. 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 designed and operated such that all gases, vapors, and fumes are routed to a process or control device.

XII.K.2.d. The owner or operator must conduct annual visual inspections of the closed vent system for defects that could result in air emissions.

XII.K.2.e. The owner or operators must conduct annual EPA Method 21 inspections to determine whether a potential leak interface operates with volatile organic compound emissions less than 500 ppm.

XII.K.2.f. In the event that a leak or defect is detected, the owner or operator must repair the defect or leak as soon as practicable. First attempt to repair must be made no later than five (5) days after detecting the defect or leak and completed no later than fifteen (15) days after detecting the defect or leak.

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

XII.K.2.g.(i) Repair is technically infeasible without a shutdown. Repair must be completed by the end of the next scheduled shutdown.

XII.K.2.g.(ii) The closed vent system is unsafe to inspect because inspecting personnel would be exposed to an immediate danger as a consequence of completing the monitoring.

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

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 a design 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 a natural gas-driven diaphragm pneumatic pump to a control device or process is technically infeasible;

XII.K.3.a.(v) Each closed vent system inspection and any resulting maintenance or repair activities; and

XII.K.3.a.(vi) Each closed vent system on the delay of inspection or repair list, 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.d.-g. and XII.K.3.a.(v)-(vi), the owner or operator may inspect, repair, and document the closed 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 requirements described in Sections XII.K.1.-4., the owner or operator may comply with natural gas-driven diaphragm pneumatic pump 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 January 1, 2018, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least on a quarterly basis.

XII.L.1.b. Owners or operators of natural gas compressor stations constructed on or after January 1, 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 on a quarterly basis.

XII.L.2. Well production facilities

XII.L.2.a. Beginning January 1, 2018, owners or operators of well production facilities with uncontrolled actual VOC emissions greater than 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 January 1, 2018, owners or operators of well production facilities with uncontrolled actual VOC 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. 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).

XII.L.2.d. Owners or operators of well production facilities constructed on or after January 1, 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 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, or other approved quantitative instrument based 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 or other approved non-quantitative instrument based 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.

XII.L.4.c. For other approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the approval according to 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 based 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. 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. If shutdown is required, the leak must be repaired during the next scheduled shutdown. 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 the repair was effective.

XII.L.5.c. Leaks discovered pursuant to the leak detection methods of Section XII.L.4. shall not be 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 new well production facilities and natural gas compressor stations;

XII.L.6.b. The date and site information 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 repair methods 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, an explanation for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after discovery due to unavailable parts must be certified by a responsible official;

XII.L.6.g. The date the leak was remonitored to verify the effectiveness of the repair, 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 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 number of well production facilities, per inspection frequency tier, and natural gas compressor stations inspected;

XII.L.7.b. The total number of leaks requiring repair, broken out by component type, monitoring method, and well production facility, per inspection frequency tier, or natural gas compressor station;

XII.L.7.c. The total number of leaks repaired and whether located at a well production facility, per inspection frequency tier, or a natural gas compressor station;

XII.L.7.d. The number and component type of leaks on the delayed repair list as of December 31st, whether located at a well production facility, per inspection frequency tier, or a natural gas compressor station, and an explanation for each delay of repair;

XII.L.7.e. 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 based monitoring device or 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. 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 ability to identify specific leak or location, 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;

XII.L.8.a.(ii)(I) Documentation, including field or test data, adequate to demonstrate the proposed alternative approved instrument monitoring method is capable of detecting leaks comparable to the repair thresholds in Section XII.L.4.;

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

XII.L.8.a.(iv) The Division and the EPA approves the proposal. The Division shall transmit a copy of the 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.

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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 device or method. Any instrument monitoring method approved by the Division must be capable of detecting leaks as defined in Section XVII.F.6. 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 storage tank thief hatch), 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.~~9~~10. "Intermediate Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid.

XVII.A.~~10~~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.~~11~~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.~~12~~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.~~13~~14. “Reciprocating Compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the ~~driveshaft~~piston rod.

XVII.A.~~14~~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.~~15~~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.~~16~~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.~~17~~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 shall 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 C.F.R. 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 C.F.R. 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) 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~~B) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(i)(~~c~~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.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 below.

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) 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~~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~~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~~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. shall 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. shall 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 shall mean 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 shall mean 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. shall 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. below, 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 the table below 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 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 2 below 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 On or after January 1, 2011	2.0 1.0	4.0 2.0	1.0 0.7
≥500 Hp	On or after July 1, 2007 On or after July 1, 2010	2.0 1.0	4.0 2.0	1.0 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.3.1.(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~~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~~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~~C) The requirements of this Section XVII.E.3.a. shall 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 ~~detected pursuant to~~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, or other Division approved quantitative instrument based monitoring, at facilities constructed before May 1, 2014, ~~a~~ repair is required for leaks ~~is~~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, or other Division approved quantitative instrument based monitoring, at facilities constructed on or after May 1, 2014, ~~a~~ repair is required for leaks ~~is~~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, or other Division approved non-quantitative instrument based monitoring, ~~a~~ repair is required for leaks ~~is~~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 monitoring devices or methods, 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 ~~defined~~ 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 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. 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. If shutdown is required, the leak must be repaired during the next scheduled shutdown. 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 the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F.6. shall not be 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 and site information 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 repair methods applied;

XVII.F.8.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, an explanation for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after discovery due to unavailable parts must be certified by a responsible official~~basis for placing leaks on the list~~;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. 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 ~~plan~~ 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 the previous calendar year:

XVII.F.9.a. The number of well production facilities and natural gas compressor stations~~facilities~~ inspected;

XVII.F.9.b. The total number of inspections per inspection frequency tier of well production facilities and natural gas compressor stations;

XVII.F.9.c. The total number of leaks requiring repair identified, broken out by component type, monitoring method, and inspection frequency tier of well production facilities and natural gas compressor stations;

XVII.F.9.d. The total number of leaks repaired per inspection frequency tier of well production facilities and natural gas compressor stations;

XVII.F.9.e. The number, component type, and inspection frequency tier of well production facilities and natural gas compressor stations of leaks on the delayed repair list as of December 31st and an explanation for each delay of repair; 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.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. ~~(State Only)~~ 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" shall mean 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 a continuous flow of pneumatic supply natural gas to 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.~~2~~4. "Enhanced Maintenance" ~~is specific to high-bleed devices and shall~~ 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.~~3~~5. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.~~4~~6. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.~~5~~7. "Natural Gas Processing Plant" shall mean 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.~~6~~8. "No-Bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.~~7~~9. "Pneumatic Controller" shall mean 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.C. Emission Reduction Requirements

The 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 ~~I~~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, shall emit VOCs 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 VOC 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 must remain in service ~~-~~due to safety and/or process purposes must ~~have Division approval and~~ 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 shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. ~~The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.~~

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation. ~~The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.~~

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 must 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/operator shall 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/operator shall submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

XVIII.C.~~2~~3. (State Only) Statewide:

XVIII.C.~~2~~3.a. ~~A~~Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014, must:

XVIII.C.~~2~~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.~~Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or~~

XVIII.C.~~2~~3.a.(ii) ~~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.~~ 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 VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.3.c.

XVIII.C.~~2~~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 VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.~~2~~3.c.

XVIII.C.~~2~~3.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must ~~have Division approval and~~ comply with Sections XVIII.D. and XVIII.E.

XVIII.C.~~2~~3.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. ~~The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.~~

XVIII.C.~~2~~3.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes thirty (30) days prior to installation. ~~The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.~~

XVIII.D. Monitoring

This section applies ~~only~~ to ~~high-bleed~~ pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.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 shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, the owner or operator must inspect each high-bleed pneumatic controller ~~shall be inspected~~ on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2., and maintain the ~~device~~ pneumatic controller according to manufacturer specifications to ensure that the controller's VOC 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 shall be physically tagged by the owner/operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner/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 enhanced maintenance as defined in Section XVIII.B.2, and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.~~2~~3. (State Only) Statewide:

XVIII.D.~~2~~3.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.~~2~~3.b. Effective May 1, 2015, the owner or operator must inspect each high-bleed pneumatic controller ~~shall be inspected~~ on a monthly basis, ~~undergo~~ perform necessary enhanced maintenance as defined in Section XVIII.B.~~2~~4., and ~~be~~ maintain~~ed~~ the pneumatic controller according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

XVIII.E.1. In the 8-Hour Ozone Control Area

XVIII.E.1.a. The owner or operator must maintain records of the total number of continuous bleed, natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant, location, and documentation that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.

XVIII.E.1.b. The owner or operator must maintain records of the total number of continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant, location, and documentation that the natural gas bleed rate is zero.

XVIII.E.1.c. Records must be maintained for a minimum of five years and records made available to the Division upon request.

XVIII.E.2. This section applies only to ~~high-bleed~~ 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 of affected operations shall maintain a log of the total number of ~~high-bleed~~ pneumatic controllers and their associated controller numbers per facility, the total number of ~~high-bleed~~ pneumatic controllers per company and the associated justification that the ~~high-bleed~~ 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 shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, ~~high-bleed~~ 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 enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.~~XVIII.E.3.~~

XVIII.F. (State Only) Pneumatic Controller Inspection and Maintenance 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 January 1, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations or 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 VOC emissions greater than 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 VOC emissions greater than six (6) tons per year.

XVIII.F.2.a.(iii) Quarterly at natural gas compressor stations.

XVIII.F.2.b. 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.c. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced maintenance or follow manufacturer specifications to return the pneumatic controller to proper operation.

XVIII.F.3. Maintenance and remonitoring

XVIII.F.3.a. Enhanced maintenance must begin no later than five (5) working days after discovering the pneumatic controller is not operating properly and the pneumatic controller returned to proper operation no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete enhanced maintenance, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced maintenance conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced maintenance must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced maintenance 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 maintenance or other actions to return the pneumatic controller to proper operation, 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 shall not be 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 maintenance or other action 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 five years and make records available to the Division upon request.

XVIII.F.4.a. The date, site information, and approved instrument monitoring method used for each inspection;

XVIII.F.4.b. A list of pneumatic controllers, including type, found not operating properly;

XVIII.F.4.c. The date(s) of enhanced maintenance and a description of the actions taken to return the pneumatic controller to proper operation;

XVIII.F.4.d. The date the owner or operator verified the pneumatic controller was returned to proper operation;

XVIII.F.4.e. The delayed repair list, including the date and duration of any period where the enhanced maintenance or other action was delayed beyond thirty (30) days after discovery due to unavailable parts, required shutdown, or delay for other good cause, an explanation for the delay, and the schedule for returning the pneumatic controller to proper operation. Delay of enhanced maintenance or other action due to unavailable parts must be certified by a responsible official; and

XVIII.F.4.f. The date the owner or operator verified the pneumatic controller was returned to proper operation.

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 that includes, at a minimum, the following information regarding pneumatic controller inspection and maintenance 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 and whether located at a well production facility or natural gas compressor station; and

XVIII.F.5.b. The number and type of pneumatic controllers on the delayed repair list as of December 31st, whether located at a well production facility or natural gas compressor station, and an explanation for each delay.

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

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

STATEMENTS OF BASIS, SPECIFIC STATUTORY AUTHORITY AND PURPOSE

XX.P. 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").

Basis

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. The Commission is adopting RACT for the oil and gas sources covered by the Oil and Gas 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 provides presumptive RACT, it does allow states the flexibility to adopt equivalent levels of controls for covered sources. 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.) were equivalent to or better 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 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. the 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 pneumatic controllers in the Ozone SIP and specify that continuous bleed 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.

Oil and Gas CTG, generally

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.

Applicability to hydrocarbons (Section II.B.)

Section II.B. currently exempts negligibly reactive hydrocarbons, such as methane and ethane, from requirements of the SIP. However, many of the revisions have the benefit of reducing both VOC and these other hydrocarbon emissions. The Commission is therefore revising Section II.B to reflect that some of the Ozone SIP revisions adopted by the Commission regulate hydrocarbons other than VOCs. The Commission makes this revision in recognition that non-VOC hydrocarbon emissions can contribute to ozone formation. Further, that the Oil and Gas CTG LDAR program employs a methane-based threshold, while the Oil and Gas CTG recommendations for pneumatic pumps speak to reducing natural gas emissions. Therefore, this revision is consistent with the Oil and Gas CTG and the CAA.

The Commission intends that the scope of the existing provisions in Section XII. will not be affected by this revision to Section II., but intends that certain requirements in Section XII.K. and XII.L. will apply to non-VOC hydrocarbons. Specifically, Section XII.K.2. requires a 95% reduction of natural gas emissions from pneumatic pumps, not just VOC emissions. Similarly, Section XII.L.4. requires repair of leaks that exceed a 500 ppm hydrocarbon threshold, not a VOC threshold (and not the methane threshold recommended by the Oil and Gas CTG). With respect to Section XVIII., the Commission intends to reduce the spectrum of natural gas emissions from pneumatic devices, where feasible.

Applicability of Section XII. (Section XII.A.)

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 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 did not support this conclusion. Therefore, in addition to the complications concerning tracking BOE, the Commission chose to rely upon an actual uncontrolled 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.

Definitions (Sections XII.B. and XVII.A.)

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 on 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 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.

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, as they existed on July 1, 2017, 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. Both Subparts VV and VVa require owners or operators to inspect equipment (e.g., valves, pumps) and repair leaks above specified thresholds. The leak repair thresholds in Subpart VVa are lower than Subpart VV for pumps in light liquid service, valves in gas/vapor service and in light liquid service, and connectors in gas/vapor service and in light liquid service. Similarly, the leak repair thresholds in Subpart OOOO are lower than Subpart KKK for pressure relief devices in gas/vapor service.

Compressors (Section XII.J.)

The Commission is adopting the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. into proposed Section XII.J. in order to include the requirements in Colorado’s Ozone SIP. The Commission intends that the requirements of Section XII.J.1. and Section XII.J.2. apply to compressors located after the well production facility and before the point of custody transfer. These sections then would not apply to compressors located at well production facilities. 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.

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. With respect to reciprocating compressors, routing to a process refers to using a rod packing emissions collecting system that operates under negative pressure and meets the cover requirements. The Commission intends that owners or operators will follow similar procedures when complying with 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, 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 create a plan 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. The Commission intends that if upon attempting the repair during shutdown, and finding that the repair was not effective upon returning to operation, the owner or operator will continue repair efforts until successful, and will not wait until the next scheduled shutdown. However, the Commission intends that owners or operators may delay repairs during the May 1 – September 30 timeframe if a subsequent shutdown will result in greater emissions than the emissions that will occur from leaving the equipment unrepaired. Stakeholders have advised, and the Commission recognizes, that unplanned shutdowns may occur, and the owner or operator may not have all necessary parts and labor in place to affect the repair. The Commission expects, however, that if the repair can be made during such an unplanned shutdown, it will be.

The Commission also adopts monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

As an alternative to complying with the control, monitoring, recordkeeping, and reporting requirements in Section XII.J., owners or operators may instead comply with centrifugal or reciprocating compressor requirements in an NSPS, including Subparts OOOO, OOOOa, or future standards.

Natural gas driven diaphragm pumps (Section XII.K.)

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 pumps located at well sites route natural gas emissions from the pneumatic pump to an onsite control device or process, unless the pneumatic pump operates on fewer than 90 days. This 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. Routing to a process generally refers to routing the emissions to a vapor recovery unit ("VRU"). The Commission also intends that when an owner or operators subsequently installs a control device or has the ability to route to a process, then the owner or operator must capture the emissions from the pneumatic pump and route the emissions to the newly installed control device or available process.

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 during the months of May – September, where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak or equipment requiring repair if a subsequent shutdown will result in greater emissions than the emissions that will occur from leaving the equipment unrepaired.

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 requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)

The Oil and Gas CTG recommends LDAR programs at well sites and gathering and boosting 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 annual or semi-annual (*i.e.* quarterly or monthly), the source may comply with Section XII.L.2. by complying with Section XVII.F. As with the LDAR inspection frequency in Section XVII.F., the Commission expects that owners and 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 production facilities 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 emissions to be reduced with the cost of the controls, and agrees that there should be a floor below which the recommended minimum frequencies shall 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 one tpy and equal to or less than six tpy are adequate to 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 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 inspection frequencies begin to apply as of January 1, 2018, the rule does not require that the first periodic inspection be completed by January 1, 2018. The Commission is permitting owners or operators to take 2018 to implement the new LDAR inspection frequencies. As a result, in 2018 owners or operators of well production facilities will need to begin annual or semi-annual LDAR monitoring and owners or operators of natural gas compressor stations will need to begin quarterly LDAR monitoring. The Commission does not require that the semi-annual monitoring be conducted in advance of this date; however, inspections done after July 1, 2017, that are in addition to current required

LDAR monitoring frequencies may count towards the first semi-annual inspection (or inspections done in the previous quarter at natural gas compressor stations).

To ensure that the Ozone SIP LDAR program works together 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, Colorado's LDAR program uses a hydrocarbon concentration threshold. The Commission has also revised Section II. of the regulation to clarify that Section XII. includes the regulation of hydrocarbons (as opposed to just VOCs).

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 5 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 exists. As with compressors and pneumatic pumps, owners or operators may delay subsequent repair attempts of equipment during the months of May – September, where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak requiring repair if a subsequent shutdown will result in greater emissions than the emissions that will occur from leaving the equipment unrepaired. 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 5 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.

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, the Commission does not intend to relieve operators of the obligation to comply with the general requirements of Section XII.C., including the requirement to minimize leakage of VOCs to the maximum extent practicable.

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 certification by a responsible official is necessary for those occasions where unavailable parts have resulted in a delay of repair beyond 30 days.

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 Ozone SIP LDAR report 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.,* well production facility or natural gas compressor station). In the State-Only LDAR program, these same records should be further reported out by well production facility or natural gas compressor station inspection frequency tier (*i.e.,* annual, quarterly, etc.). 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).

Alternative approved instrument monitoring method ("AIMM")

The Commission has adopted a process for the review and approval of alternative instrument based 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 based 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 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 detecting leaks comparable to the leaks requiring thresholds specified in the SIP for an infra-red camera or EPA's Method 21 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. The Commission intends that the rule be flexible enough to allow the Division to consider alternatives, as long as the applicant can demonstrate that the proposed method is comparable to approved methods.

Clarifications

The Commission is also 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 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.

Pneumatic controllers (Section XVIII.)

The Commission is adopting both Ozone SIP and State-Only revisions to Section XVIII.

The Commission added a definition of continuous bleed pneumatic controller, which corresponds to the Oil and Gas CTG. The Commission also added "continuous bleed" to several provisions throughout Sections XVIII.C.-E. to clarify that the earlier revisions from 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 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. The requirements to submit a justification for a pneumatic controller exceeding the emission standard to the Division, as well as the requirements for maintenance, tagging, and records, duplicate and are intended to be consistent with existing requirements related to high-bleed pneumatic controllers. 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.

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 Commission recognized that there may be situations where that was not technically or economically feasible, and excluded those situations from the requirements of the rule. The Commission provided that if powering the controller with electrical power was not feasible, owners or operators could install a pneumatic controller with VOC emissions equal to or less than a low-bleed pneumatic controller. The Commission has learned that owners or operators were not interpreting this rule consistently with the Commission's intentions. Recognizing that the rule could fairly be described as ambiguous, and even though the Commission believes its intent was clear, the Commission has clarified its intent that the first option is to install a no-bleed pneumatic controller in these revisions.

The Commission directs the Division to use discretion in determining whether to pursue enforcement against owners or operators who did not comply between 2014 and the current clarification. 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 who, based on a mis-reading of the regulation, did not install a no-bleed pneumatic controller to evaluate whether retrofitting controllers at this time is technically and economically feasible.

The Commission intends that controllers that emit gas, but from which emissions are captured (because the controller is enclosed) and routed to a control device, be a permissible no-bleed option for owners or operators in complying with this provision.

Natural gas driven pneumatic controller inspection and maintenance (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 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 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 the revisions are proposed as State-Only and are not made part of the Ozone SIP at this time. Natural gas-driven pneumatic controllers can be continuous bleed, intermittent vent, and self-contained (zero-bleed) 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 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 maintenance 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 Section XII.L. to all natural gas driven pneumatic controllers. The Commission is requiring that all natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations 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 or semi-annually, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly. 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.

The pneumatic controller inspection and maintenance 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 maintenance or repair 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 conduct enhanced maintenance 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. 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, enhanced maintenance, found in Section XVIII.B. related to maintaining high-bleed pneumatic controllers. The Commission has expanded this definition to guide the maintenance of 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 maintenance program because industry has proposed to study 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; and other related information. 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 industry representatives, Division staff, 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 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 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 CAA requires that Colorado's Ozone SIP include RACT for all sources covered by a 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; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless 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 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 the subject of 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.

(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., 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 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) 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 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. The Commission is not aware of a timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Sections XII. and XVIII. 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.

(VII) The revisions to Regulation Number 7 Sections XII. and XVIII. 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, 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 compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants.

(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.

(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.

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