ECONOMIC IMPACT ANALYSIS
(Final Analysis)

Item Title: Regulation Number 7

Meeting Date: December 17-19, 2019

ISSUE

The Air Pollution Control Division (Division) is proposing revisions to the Air Quality Control Commission (AQCC)'s Regulation Number 7 to address Senate Bill 19-181, as well as ozone, streamlining and updating the regulation, and making any necessary typographical, grammatical, and formatting corrections. The Division proposes to include several revisions in Colorado's State Implementation Plan (SIP) as streamlining, clarifications, SIP strengthening, and concerning reasonably available control technology (RACT) provisions for major sources of volatile organic compounds (VOC) and/or nitrogen oxides (NOx).

Two elements of this proposal include recommendations from the Statewide Hydrocarbon Emissions Reduction (SHER) team, formed in response to the Air Quality Control Commission's November 2017 directive to form a stakeholder process to make recommendations on state-wide hydrocarbon emissions reduction strategies for the oil and gas sector. Notably, these SHER team recommendations on addressing emissions from pneumatic controllers and the transmission segment are being made in advance of the January 2020 timeline.

Senate Bill 19-181: Minimizing emissions from the oil and gas sector

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the AQCC. This proposed rulemaking focuses on the AQCC directives in § 25-7-109, Colorado Revised Statutes (CRS), which bolster the AQCC's existing authority to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the AQCC should consider including semi-annual leak detection and repair inspection requirements at well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This proposed rulemaking addresses many of the specific provisions for consideration, though not continuous methane monitoring, and is expected to be the first of several rulemakings brought before the AQCC to implement SB 19-181.

Therefore, the Division requests that the AQCC consider proposed revisions to Regulation Number 7 to further minimize emissions from the oil and gas sector. The Division proposes to increase certain leak detection and repair (LDAR) inspection frequencies, expand inspection requirements for pneumatic controllers, revise the thresholds at which a storage tank is subject to control, expand the well emissions best management practices (BMP) requirements, require new storage tanks to use an automatic tank gauging system, require the control of emissions from storage tank unloading, and establish a performance based emission reduction program for the downstream transmission segment. The Division is also proposing annual emissions inventory and reporting requirements for the oil and gas sector.

<u>Ozone reclassification</u>

On May 4, 2016, the U.S. Environmental Protection Agency (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) of 75 parts per billion (ppb). EPA, therefore, reclassified the Denver Metro North Front Range (DMNFR) to Moderate and required attainment of the NAAQS no later than July 20, 2018. On August 15, 2019, EPA proposed to reclassify the DMNFR to Serious, after 2015-2017 ozone data failed to show attainment, requiring attainment of the 2008 ozone NAAQS no later than July 20, 2021.

Separately, EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Colorado must act aggressively to attain both of these standards and submit the necessary revisions to its SIP to address both the Clean Air Act's (CAA) more rigorous Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A serious SIP revision must include Reasonably Available Control Technology (RACT) requirements for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tons per year (tpy) or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

To address the CAA RACT SIP requirements for Serious nonattainment areas, the Division requests that the AQCC consider proposed revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx including expanding the combustion equipment requirements currently applicable to major sources over 100 tpy

VOC and/or NOx, incorporating specific New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutant (NESHAP) requirements, a categorical rule concerning general solvent use, and adopting a requirement that specific sources submit RACT analyses to the Division.

Other revisions

In an effort to improve the organization and thus usability of Regulation Number 7, the Division is proposing to reorganize Regulation Number 7 into five parts. The Division has provided a crosswalk, attached to this proposal packet, to assist in understanding the reorganization.

As a SIP clean-up effort, the Division requests that the AQCC consider proposed revisions to Regulation Number 7, Part B, Sections IV. and VII. and Appendix E to update the gasoline transport truck testing and associated recordkeeping requirements and update and clarify the vapor system requirements.

The Division also proposes clean-up corrections to the requirements for major source combustion equipment adopted in July 2018.

The Division may also make typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7 are SIP revisions, with the exception of revisions to State Only requirements in Part D, Sections II. and III.

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), CRS, 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.

Section 25-7-110.5(4)(c), C.R.S. further provides that:

> The proponent and the division shall select one or more of the following economic impact analyses. The commission may ask affected industry to submit information with regard to the cost of compliance with the proposed rule, and, if it is not provided, it shall not be considered reasonably available. The economic impact analysis required by this subsection (4) shall be based upon reasonably available data…

For the purposes of this Initial Economic Analysis the Division has chosen to use the methodology set forth in § 25-7-110.5(4)(c)(I), CRS.

COST-EFFECTIVENESS ANALYSIS

The Division's assessment of the costs and benefits for each of the proposed strategies is set forth below. For each strategy, these assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements. Finally, the Division considered whether there would be any additional costs for the Division to implement the proposed requirements beyond current expenditures and determined that the proposed revisions could be implemented using existing resources.

I. Controls for Petroleum Storage Tanks

Colorado has adopted numerous control requirements to reduce emissions from storage tanks at oil and gas exploration and production and other facilities. The

Division is proposing several new regulatory provisions aimed at reducing VOC, methane, and other hydrocarbon emissions from this category of sources. For the purposes of this analysis the Division assumes that operators will use enclosed flares to control emissions from storage tanks.

A. General Cost Estimates for Flares

In Table 1, the Division has estimated the annualized cost of an enclosed flare, ancillary equipment, pilot fuel, installation along with operation and maintenance based on identified costs from a 2008 oil and gas cost study[1] adjusted for inflation[2]. Based on this information, the estimated annualized cost of a flare control device with auto-igniter[3] is about $6,488.

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	$19,245			
Freight/Engineering		$1,745		
Flare Installation		$7,393		
Auto Igniter	$1,745			
Pilot Fuel**			$642	
Maintenance			$2,327	
Subtotal Costs	$20,990	$9,138	$2,969	
Annualized Costs***	**$2,909**	**$609**	**$2,969**	**$6,487.7**

** All the flare control device costs were escalated by 16.35% to reflect CPI-U increases that have occurred since the 2008 rulemaking.*
*** Pilot fuel costs based on $2.85/MMBtu (Henry Hub Spot Price average January - April 2019)*
**** Annualized costs are over a 15 year period assuming a 5% rate of return*

B. Replace the 90%/70% system-wide condensate storage tank control program in the DMNFR with a discrete threshold-based control requirement for storage tanks ≥ 2 tons per year (tpy) of uncontrolled actual VOC emissions.

Despite significant population growth and increased economic activity, the DMNFR region has seen gradual improvement in ozone levels over the past 20

[1] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process.
[2] Inflation adjustment over the period 2008-2018 was estimated at 16.35 % using US Department of Labor CPI-U annual data.
[3] Currently all flares in the state are required to have auto-igniters.

years, largely from significant reductions in ozone precursor emissions. However, ozone levels remain above the 2008 and 2015 National Ambient Air Quality Standards (NAAQS) and the DMNFR is facing a pending reclassification to a “Serious” nonattainment area for the 2008 standard. Despite significant decreases in emissions since 2004, presently, condensate tanks remain the largest single source of VOC emissions in the DMNFR. Given the region’s ozone problems, and the administrative complexity of the current regulatory program, the Division proposes to transition from the current system-wide approach of controlling VOC emissions to a more stringent control program requiring control of all storage tanks with uncontrolled actual emissions of greater than or equal to 2 tpy.

Presently, Colorado’s ozone SIP specifies in Section XII.D.2 of Regulation Number 7 that owners and operators of all condensate tanks emitting ≥ 2 tpy meet a 90% system-wide control requirement on a weekly basis during the summer ozone season May 1st through September 30th. During the remainder of the year, operators must meet a 70% control requirement. The regulation provides exemptions from the system-wide control program to small operators with total company-wide emissions under 30 tpy. Operators are required to submit semi-annual reports to the Division detailing the number of tanks, condensate production, the presence of a control device on the individual tank (or tank battery), and the operational status. While many of the condensate tanks in the DMNFR are already controlled pursuant to the existing system-wide control program and a state-wide program requiring controls on storage tanks with uncontrolled actual emissions greater than or equal to 6 tpy, the transition to a 2 tpy tank control threshold will require operators to install additional controls.

1. *Condensate Tank Count*

All non-exempt operators in the DMNFR are required to submit system-wide control reports to the Division semi-annually. Based on operator reported data for 2017, Table 2 shows there are 5,028 condensate tank batteries[4] in the DMNFR that are subject to Regulation 7 system-wide requirements. At the proposed tank control threshold of ≥ 2 tpy, there are 65 condensate tanks that do not have emission controls.

Table 2: Condensate Tank Count Based on Reg. 7 System-wide Control Reports

Tank Battery Size*	Count of NAA Tanks	Count of NAA Tanks w/Controls**	Count of NAA Tanks w/out Controls
≥ 4 tpy	1,812	1,803	9

[4] In the DMNFR, owners and operators of condensate tanks with total actual uncontrolled VOC emissions less than 30 tpy are exempt from system-wide control requirements and therefore are excluded from the above listed total. Analysis of these currently exempt tanks is addressed below.

≥ 3 tpy to < 4 tpy	285	265	20
≥ 2 tpy to < 3 tpy	409	373	36
Subtotal	**2,506**	**2,441**	**65**
≥ 1 tpy to < 2 tpy	703	571	132
≥ 0 tpy to < 1 tpy	1,219	959	260
= 0 tpy	600	-	-
Subtotal	2,522	1,530	392
Grand Total	**5,028**	**3,971**	**457**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

2. *Emission Reductions From Controlling DMNFR Condensate Tank ≥ 2 TPY*

Using the Regulation Number 7 system-wide reports for 2017, there are a potential 65 condensate storage tanks without emission controls at the proposed ≥ 2 tpy storage tank control threshold in the DMNFR. The Division assumes that 100 percent of the flash gas in the storage tank is captured and routed to a control device through the implementation of Storage Tank Emissions Management (STEM) system requirements.[5] As reflected in Table 3, controlling emissions from these tanks will reduce VOC emissions by 188.93 tpy using an assumed 95 percent control device effectiveness[6].

Table 3: Condensate Tank Emission Reductions

Tank Battery Size	Count of NAA Tanks w/Controls	Count of NAA Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 4 tpy	1,803	9	40.78
≥ 3 tpy to < 4 tpy	265	20	66.00
≥ 2 tpy to < 3 tpy	373	36	82.15
Total	**2,441**	**65**	**188.93**

3. *Cost Effectiveness*

Table 4 provides the annualized cumulative cost of installing 65 flare control devices is about $421,700 dollars with an average cost effectiveness of about $2,232 per ton of VOC reduced. For the smallest category of tanks (2-3 tpy) the

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[5] See Regulation Number 7, Section 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."
[6] Generally flares can achieve a destruction efficiency of 98 percent, but the Division assumes 95 percent control to account for some downtime.

incremental cost of controls on 36 tanks is estimated at $2,843 per ton of VOC reduced.

Table 4: Incremental Control Cost Estimates for Flare Control Devices on Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[7]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 4 tpy	9	$6,487.7	$58,389	40.78	$1,432
≥ 3 tpy to < 4 tpy	20	$6,487.7	$129,754	66.00	$1,966
≥ 2 tpy to < 3 tpy	36	$6,487.7	$233,557	82.15	$2,843
All tanks	65	$6,487.7	$421,700	188.93	$2,232

In order to preserve flexibility in controlling smaller storage tanks that may have very low VOC concentrations that potentially may not be controlled if supplemental firing of natural gas is necessary to control emissions, the Division is proposing to establish in the SIP a control requirement for storage tanks ≥ 4 tpy. At the ≥ 4 tpy threshold, 91.5% control is achieved, thus no SIP backsliding occurs because VOC emission reductions exceed the required 90% system-wide control requirement by 1.5% The control requirement for storage tanks ≥ 2 tpy but < 4 tpy are proposed as "state-only".

C. *Remove the Part E, Section I.A.7 exemption (associated with the system-wide control program) for owners or operators of condensate tanks with total actual uncontrolled VOC emissions less than 30 tpy.*

Regulation Number 7 provides for an exemption from the system-wide control requirement for small condensate tank operators with total VOC emissions less than 30 tpy. Since these operators are exempt from system-wide reporting and Air Pollutant Emissions Notice (APEN) reporting is infrequent, it is difficult to ascertain how many tanks are using the exemption. Based on 2019 COGCC data, there are 67 operators reporting tank operations in Weld County. If the operators reporting to system-wide in Weld County are removed, there are about 46 operators reporting oil production that may have condensate tanks above the proposed 2 tpy VOC emission control threshold that would lose the 30 tpy exemption from control. The 46 operators also include 17 operators that report zero oil production for the first six months of 2019, but who could presumably produce condensate at some point in the future.

The Division assumes that any condensate tanks previously exempted from control would fall into an uncontrolled VOC tank size range between ≥ 2 to < 6

[7] See Table 1 for estimated annualized cost of flare controls.

tpy because all storage tanks statewide must be controlled if the emissions ≥ 6 tpy. The estimated number of condensate tanks potentially impacted by the proposed ≥ 2 tpy threshold control requirement could be as high as 690 tanks assuming all 46 operators were just below the 30 tpy exemption threshold and all had 15 tanks equal to the 2 tpy threshold. A lower number of tanks potentially impacted by the proposed ≥ 2 tpy threshold control requirement is about 230 tanks assuming all 46 operators were just below the 30 tpy exemption threshold and all had 5 tanks just below the 6 tpy threshold. It is more likely that most operators have a few tanks and some will have no tanks above the ≥ 2 tpy threshold. If the Division assumes that all 46 operators have at least three tanks ≥ 2 tpy, the number of tanks subject to control is estimated at 138 tanks. Operators with condensate tanks below the 2 tpy threshold would not incur any additional control costs.

Although the Division is currently unable to establish the exact number of condensate tanks impacted by the proposal to remove the 30 tpy exemption for condensate tanks, the control costs should be similar to the incremental control cost estimates presented in Table 4. The Division has previously requested more information from operators impacted by the removal of the 30 tpy condensate tank exemption but has yet to receive any such information.

D. Require controls on crude oil and produced water tanks in the DMNFR with uncontrolled actual emissions of 2 tpy VOC or greater.

Currently, in Part D, Section I (formerly Section XII) of Regulation Number 7 only condensate tanks ≥ 2 tpy are subject to the system-wide emission control requirement. Other storage tanks (crude oil and produced water) are subject to controls in Part D, Section II (formerly Section XVII) of Regulation Number 7, and then only if the uncontrolled actual VOC emissions ≥ 6 tpy. Consequently, there are a number of crude oil and produced water tanks over the proposed ≥ 2 tpy threshold that are not currently required by Regulation Number 7 to have controls in the DMNFR.

Based on most recently available Regulation Number 7 APEN reported data (for 2018) on crude oil and produced water tanks, Table 5 shows there are 605 crude oil and water tank batteries[8] in the DMNFR. At the proposed storage tank control threshold of ≥ 2 tpy, there are 175 tanks that are reported as not having emission controls that will need to install controls.

Table 5: DMNFR Crude Oil & Produced Water Tank Battery Analysis (2018 APEN Data)

Tank Battery Size*	Count of NAA Tanks	Count of NAA Tanks w/Controls**	Count of NAA Tanks w/out Controls

[8] Crude oil and water tanks are determined by screening by respective source classification codes 404003012 and 4040003015.

≥ 4 tpy	417	371	46
≥ 3 tpy to < 4 tpy	58	25	33
≥ 2 tpy to < 3 tpy	130	34	96
Total	**605**	**430**	**175**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

Table 6 shows the estimated 611.4 tpy VOC emission reduction associated with the proposed control requirements on 175 crude oil and produced water tanks ≥ 2 tpy in the DMNFR.

Table 6: DMNFR Emission Reductions from Crude Oil & Produced Water Tank Controls

Tank Battery Size	Count of NAA Tanks w/Controls	Count of NAA Tanks w/out Controls	VOC Reduction[9] from Added Controls (tpy)
≥ 4 tpy	371	46	269.8
≥ 3 tpy to < 4 tpy	25	33	108.0
≥ 2 tpy to < 3 tpy	34	96	233.6
Total	**430**	**175**	**611.4**

For crude oil and water tanks in the DMNFR, Table 7 provides the estimated annualized cost of installing 175 flare control devices at about $1.14 million dollars with an average cost effectiveness of about $1,857 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 96 tanks is estimated at $2,666 per ton of VOC reduced. Produced water tanks generally have lower hydrocarbon concentrations, which could limit flare control effectiveness and may require supplemental fuel to support effective combustion of the hydrocarbon vapors. The Division requested more information about the level of hydrocarbon concentrations triggering the use of supplemental fuel and quantity of supplemental fuel used but has not yet received such information.

Table 7: DMNFR Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy

[9] The VOC emission reduction is calculated assuming the use of enclosed flare control operating at 95% control effectiveness.

Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[10]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 4 tpy	46	$6,487.7	$298,434	269.8	$1,106
≥ 3 tpy to < 4 tpy	33	$6,487.7	$214,094	108.0	$1,982
≥ 2 tpy to < 3 tpy	96	$6,487.7	$622,819	233.6	$2,666
All tanks	**175**	**$6,487.7**	**$1,135,348**	**611.4**	**$1,857**

E. Lower the existing statewide control requirement threshold for condensate, oil and produced water storage tanks from ≥ 6 tpy to ≥ 2 tpy of uncontrolled actual VOC emissions and increase the approved instrument monitoring method (AIMM) inspection frequency from annual to semi-annual for storage tanks with VOC emissions $\geq$ 6 to $\leq$ 12.

Based on APEN reports for the most recent complete data year (2018), the Division evaluated the number of condensate, crude oil, and produced water tanks that may need to install controls for areas outside of the DMNFR (referred to herein as the "remainder of the state (ROS)") including the areas north and east of the DMNFR. The Division acknowledges that the APEN reporting system allows flexibility in reporting (up to every 5 years), which may produce inaccurate counts for each tank battery size tier, particularly if well production has declined since the most recently filed APEN report has occurred. Accordingly, the actual number of tanks without controls evaluated in this proposal may differ from the APEN reported data. The Division requested more information about the number of statewide uncontrolled storage tanks that may impacted by this rulemaking proposal but has yet to receive such information.

Table 8 shows there are about 588 crude oil and produced water tank batteries[11] in the ROS. At the proposed storage tank control threshold of ≥ 2 tpy, there are 202 tanks that are reported as not having emission controls.

Table 8: ROS Crude Oil & Produced Water Tank Battery Analysis (2018 APEN Data)

Tank Battery Size*	Count of ROS Tanks	Count of ROS Tanks w/Controls**	Count of ROS Tanks w/out Controls
≥ 4 tpy	392	320	72
≥ 3 tpy to < 4 tpy	83	33	50

[10] See Table 1 for estimated annualized cost of flare controls.

[11] Crude oil and water tanks are determined by screening by respective source classification codes 404003012 and 4040003015.

≥ 2 tpy to < 3 tpy	113	33	80
Total	**588**	**386**	**202**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

Table 9 shows the estimated 866.7 tpy VOC emission reduction associated with the proposed control requirements on the 202 crude oil and produced water tanks ≥ 2 tpy in the ROS.

Table 9: ROS Emission Reductions from Crude Oil & Produced Water Tank Controls

Tank Battery Size	Count of ROS Tanks w/Controls	VOC Reduction from Existing Controls (tpy)	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 4 tpy	320	26,905.3	72	506.2
≥ 3 tpy to < 4 tpy	33	197.7	50	167.4
≥ 2 tpy to < 3 tpy	33	110.5	80	193.1
Total	**386**	**27,092.9**	**202**	**866.7**

For crude oil and water tanks in the ROS, Table 10 provides the estimated annualized cost of installing 202 flare control devices at about $1.31 million dollars with an average cost effectiveness of about $1,512 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 80 tanks is estimated at $2,688 per ton of VOC reduced.

Produced water tanks generally have lower hydrocarbon concentrations, which could limit flare control effectiveness and may require supplemental fuel to support effective combustion of the hydrocarbon vapors. Generally, the firing of supplemental fuel in a flare control device defeats the fundamental purpose of the control device, which is to reduce emissions and not increase them. Accordingly, the Division is proposing to allow operators to submit a technical demonstration showing that supplemental fuel is necessary for safe and effective combustion of the hydrocarbon vapors in situations where a tank has very low hydrocarbon vapor concentrations. The Division requested more information about the safety associated with combusting very low hydrocarbon vapor streams, the hydrocarbon concentration threshold triggering the use of supplemental fuel and quantity of supplemental fuel necessary for safe and effective combustion but has yet to receive such information.

Table 10: ROS Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[12]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 4 tpy	72	$6,487.7	$467,114	506.2	$923
≥ 3 tpy to < 4 tpy	50	$6,487.7	$324,385	167.4	$1,938
≥ 2 tpy to < 3 tpy	80	$6,487.7	$519,016	193.1	$2,688
All tanks	202	$6,487.7	$1,310,515	866.7	$1,512

In addition to crude oil and produced water tanks, there are about 874 condensate tank batteries[13] based on 2018 APEN reported data in the ROS. At the proposed storage tank control threshold of ≥ 2 tpy, Table 11 shows there are about 444 tanks that are reported as not having emission controls.

Table 11: ROS Condensate Tank Battery Analysis (2018 APEN Data)			
Tank Battery Size*	Count of ROS Tanks	Count of ROS Tanks w/Controls**	Count of ROS Tanks w/out Controls
≥ 4 tpy	522	369	153
≥ 3 tpy to < 4 tpy	140	24	116
≥ 2 tpy to < 3 tpy	212	37	175
Subtotal	**874**	**430**	**444**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

Table 12 shows the estimated 1,715.2 tpy VOC emission reduction associated with the proposed control requirements on the 444 condensate tanks ≥ 2 tpy in the ROS.

Table 12: ROS Emission Reductions from Condensate Tank Controls			
Tank Battery Size	Count of ROS Tanks w/Controls	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)

[12] See Table 1 for estimated annualized cost of flare controls.
[13] Condensate tanks are determined by screening by source classification code 404003011.

≥ 4 tpy	369	153	929.9
≥ 3 tpy to < 4 tpy	24	116	382.3
≥ 2 tpy to < 3 tpy	37	175	403.1
Total	**430**	**444**	**1,715.2**

For condensate tanks in the ROS, Table 13 provides the estimated annualized cost of installing 444 flare control devices at about $2.88 million dollars with an average cost effectiveness of about $1,679 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 175 tanks is estimated at $2,817 per ton of VOC reduced.

Table 13: ROS Control Cost Estimates for Condensate Tanks ≥ 2 tpy

Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[14]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 4 tpy	152	$6,487.7	$992,618	929.9	$1,068
≥ 3 tpy to < 4 tpy	116	$6,487.7	$752,573	382.3	$1,969
≥ 2 tpy to < 3 tpy	175	$6,487.7	$1,135,348	403.1	$2,817
All tanks	444	$6,487.7	$2,880,539	1,715.2	$1,679

Storage tanks with emissions ≥ 2 and less than 6 tpy will have to conduct AVO and visual inspections every 7 to 31 days. The Division is also proposing to add to the visual inspection requirements inspections of dump valves and liquid knockout vessels. These proposed requirements are based on the storage tank guidelines developed by the Division and industry, and are generally assumed to be conducted by most operators already.

The Division is also proposing semi-annual AIMM inspections of storage tanks with emissions greater than or equal to 2 and less than 6 and to increase the AIMM inspection frequency from annual to semi-annual for storage tanks with emissions greater than or equal to 6 and less than or equal to 12 tpy. These inspections are intended to align with the leak detection and repair (LDAR) inspections, discussed below.

[14] See Table 1 for estimated annualized cost of flare controls.

II. Leak Detection and Repair (LDAR) for well production facilities and natural gas compressor stations

In 2014, the AQCC adopted LDAR requirements for well production facilities and natural gas compressor stations. Recently adopted Colorado Senate Bill 19-181 requires that the AQCC review its rules for oil and gas well production facilities and compressor stations and specifically consider adopting more stringent provisions including increasing the well production facility LDAR inspection frequency to a minimum of semi-annual. In recognition of SB 19-181, the Division is proposing to increase the frequency of AIMM inspections at well production facilities and compressor stations. In addition to proposing semi-annual LDAR inspections, the Division is proposing to require semi-annual AIMM inspections for storage tanks at these facilities so that the inspection schedules for tanks and components continue to align. Since operators will be conducting LDAR inspections at these facilities, the additional cost of an AIMM inspection on the tanks at that facility should be minimal. Accordingly the Division has not separately assessed the costs of increasing the AIMM inspections for storage tanks

Consistent with the 2014 Oil and Gas Rulemaking[15] the Division is using an identical multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair 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.[16] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment (including an infrared camera) and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in the Divisions' 2014 Final Economic Impact Analysis, the total annual cost for each inspector is estimated at $193,629, which equates to an hourly inspection rate of $103. The Division adjusted the hourly inspection rate by 5.53% to account for cost increases since 2014. The 2019 "In-house" hourly inspection rate rounded to the nearest dollar is $109.

Table 14: Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis

Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
FLIR Camera Maintenance/Repair		$7,500	

[15] See the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014.
[16] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

Photo Ionization Detector	$5,000		
Vehicle (4x4 Truck)	$22,000		
Inspection Staff		$75,000	
Supervision (@ 20%)		$15,000	
Overhead (@10%)		$7,500	
Travel (@15%)		$11,250	
Recordkeeping (@10%)		$7,500	
Reporting (@10%)		$7,500	
Fringe (@30%)		$22,500	
Subtotal Costs	$149,000	$153,750	
Annualized Costs*	$39,879	$153,750	$193,629
		2014 Annualized “In-house” Hourly Rate	$103
		2014 Annualized “Contractor” Hourly Rate**	$134
		2019 Annualized “In-house” Hourly Rate***	$109
		2019 Annualized “Contractor” Hourly Rate	**$142**

** Annualized over 5 year period at 6% rate of return*
*** Contractor rate 30% higher than In-house rate*
**** Adjusted by 5.53% to account for inflation since 2014*

In the 2014 Oil and Gas Rulemaking, the Division analyzed both “in-house” and “contractor” options for conducting LDAR inspections. The Division recognizes that in-house inspections would be the lowest cost option for larger operators since it would not involve additional profit to be paid to a contractor. However, for smaller companies that cannot fully utilize an IR camera, conducting inspections in-house may not be the most cost effective option. To account for these differences, the Division assumed a 30% profit margin for contractors, which is added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection ($142 per hour). Considering the complex mix of large and small oil and gas operations, impacted by this proposal, including some potentially exempted from previous regulatory requirements in the DMNFR, the Division is using the contractor cost option to simplify the analysis. Despite using the higher hourly cost ($142), the foregoing analysis shows that the proposed increase in inspection frequency and repair is shown to be cost effective.

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at 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. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. 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, on average, take 50% of the time required for a Method 21 inspection.[17] In its role as staff to the AQCC, the Division requests additional information on the time and costs associated with conducting IR camera based inspections.

For compressor stations, the Division used APEN reported component counts for the ≤ 12 tpy inspection tier identified in Table 15. Based on these counts, and the inspection times per component discussed above, the Division calculated the following total inspection time per compressor station facility at the ≤ 12 tpy inspection tier:

Table 15: Calculated Inspection Time Compressor Station Leak Inspections

Component Leak Uncontrolled Actual VOC Emissions	Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	Rest of State	23.1 hours	11.6 hours

For well production facilities, the Division has limited APEN data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the DMNFR and well production facilities in the ROS. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 16.

Table 16: Calculated Inspection Times for Well Production Facility Leak Inspections

Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
DMNFR	12.2 hours	6.1 hours
Remainder of the State	6.8 hours	3.4 hours

[17] Based on the Division's own IR camera inspections, and reports from various parties during the 2014 stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 16, the Division also assumed an additional three hours in travel time for each inspection in the ROS. This assumption reflects the fact that certain well sites in basins in the ROS area may be remote, requiring additional travel.

Third, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported APEN emission data to determine the number of facilities that will be subject to semi-annual inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For both compressor stations and well production facilities the Division assumed that all inspections would be conducted by 3rd party contractors. Since owners and operators of both compressor stations and well production facilities are already subject to recordkeeping and reporting, the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In the assessment of repair costs the Division also 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 $74.95 hourly rate[18] to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the both type of component and the complexity of the repair.[19] To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.48% leaking component rate for facilities subject to semi-annual inspections. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to thousand cubic feet ("MCF") of natural gas, with a price of $2.92/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible. The subsequent LDAR cost analysis is based on the above methodology.

Since Colorado's leak detection and repair program has been in place for a number of years, some industry stakeholders have questioned if a lower leak frequency or leaking component rate should be used in the LDAR technical analysis. Presently, the Regulation Number 7 LDAR inspection reports show the number of facilities inspected and number of leaks found, but no information

[18] The $66.24 hourly rate adjusted by 13.15% to account for inflation since 2009

[19] 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.

on the number of components. One important observation from the Regulation Number 7 LDAR inspection reports is that more site visits results in the identification and repair of more leaks. In light of limited data, the Division used EPA data that indicated an annual leak frequency of 1.18%. Since this Regulation Number 7 proposal involves more inspections (i.e. moving from annual LDAR to semi-annual LDAR), the Division is using a scaled semi-annual leak frequency of 1.48%. In response to questions on whether a lower leak rate should be used, the Division evaluated the effect of a lower leak frequency. If the leak frequency is reduced by half (i.e. 0.74%) the total net LDAR cost decreases because the resulting costs of leak detection stay the same but the costs of leak repair go down because fewer leaks are needing to be repaired.

A. ***Increase the LDAR inspection frequency at well production facilities: from annual to semi-annual for well production facilities in the DMNFR with VOC emissions ≥ 2 tpy to ≤ 6 tpy; from one-time to semi-annual for well production facilities outside the DMNFR with VOC emissions ≥ 2 tpy to ≤ 6 tpy; and from annual to semi-annual for well production facilities outside the DMNFR with actual VOC emissions > 6 tpy to ≤ 12 tpy.***

Under Regulation Number 7, LDAR frequency at well production facilities with storage tanks is based on the uncontrolled actual VOC emissions of the largest emitting storage tank at the facility. To calculate the number of facilities that will be subject to additional LDAR inspections at well production facilities the Division used a combination of Regulation Number 7 system-wide operator reported data and 2018 APEN data for storage tanks. Table 17 lists the number of well production facilities throughout the state and the current inspection frequency along with the proposed changes to the inspection frequency for the various facility tiers.

Table 17: Storage Tank Battery Analysis for LDAR at Well Production Facilities

Uncontrolled VOC at Storage Tank Battery Tier	O & G Basin*	Current Inspection Frequency	Proposed Changes to Inspection Frequency	Total Number of Facilities
> 0 to < 1 tpy	DMNFR	One-time		1,294
≥ 1 to < 2 tpy	DMNFR	Annual		915
≥ 2 to ≤ 6 tpy	DMNFR	Annual	Semi-annual	1,384
> 6 to ≤ 12 tpy	DMNFR	Semi-annual		718

			Subtotal:	4,311
> 0 to < 2 tpy	ROS	One-time		466
≥ 2 to < 6 tpy	ROS	One-time	Semi-annual	809
≥ 6 to < 12 tpy	ROS	Annual	Semi-Annual	193
			Subtotal:	1,468
			Total	5,779

* ROS = Remainder of State

In the DMNFR, Regulation Number 7 requires owners and operators of well production facilities with uncontrolled actual VOC emissions >1 tpy to ≤ 6 tpy to conduct an annual LDAR inspection and those > 6 tpy to ≤ 12 tpy to conduct a semi-annual LDAR inspection. For the ROS, owners and operators of well production facilities with emissions > 2 tpy to < 6 tpy must conduct a one-time LDAR inspection and those ≥ 6 tpy to < 12 tpy must conduct an annual LDAR inspection. The LDAR inspection requirement specifies that owners and operators must conduct periodic inspections using EPA Reference Method 21 or IR camera and repair leaks within a prescribed time frame. In Table 18, the Division estimates the increase in inspection frequency at some well production facilities will result in an additional 3,195 inspections at a cost of about $2.8 million dollars.

Table 18: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin*	Number of Facilities	Change in Annual Inspection Frequency	Total Number of New Inspections	Inspection Time Per Inspection (hours)	Total Annual Inspection Cost
Contractor Inspections at $142/hour						
> 0 to < 1	DMNFR	1,294	0	0	0	-
≥1 to <2 tpy	DMNFR	915				
≥ 2 to < 6	DMNFR	1,384	1	1,384	6.1	$1,198,821
≥ 6 to < 12	DMNFR	718	0	0	0	
Subtotal:		4,311		1,384		$1,198,821

Contractor Inspections at $142/hour						
> 0 to < 2	ROS	466	0	0	0	-
≥ 2 to < 6	ROS	809	2	1,618	6.4**	$ 1,470,438
≥ 6 to < 12	ROS	193	1	193	6.4**	$175,398
Subtotal:		1,468		1,811		$1,645,836
Total (Contractor Inspections):				**3,195**		**$2,844,657**

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Based on the average leak rate, repair time, and hourly repair rate discussed above, the Division calculated that leak repair costs resulting from the proposed new LDAR inspection frequency will total about $2.2 million dollars as reflected in Table 19.

Table 19: Well Production Facility Leak Repair Costs

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Number of Tanks (Facilities)	Total Leak Repair Time per Facility (hours)	Total Annual Repair Cost
> 0 to < 1	DMNFR	1,294		
≥1 to <2 tpy	DMNFR	915		
≥ 2 to < 6	DMNFR	1,384	14.8	$1,535,216
≥ 6 to < 12	DMNFR	718		
Subtotal:		4,311		$1,535,216
> 0 to < 2	ROS	466		
≥ 2 to < 6	ROS	809	9.6	$582,092
≥ 6 to < 12	ROS	193	9.6	$138,867
Subtotal:		1,468		$720,959

		Total:	**$2,256,175**

In Table 20, the Division estimates the total value of recovered natural gas from the repair of leaks based on the newly required inspections at about $676,256 dollars.

Table 20: Well Production Facility Recovered Natural Gas Value from Leak Repairs

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Number of Facilities	Total Recovered Natural Gas per facility (tons/year)	Value of Natural Gas ($/MCF)	Conversion Factor (MCF/ton)	Total Annual Value of Recovered Natural Gas
> 0 to < 1	DMNFR	1,294				
≥1 to <2 tpy	DMNFR	915				
≥ 2 to ≤ 6	DMNFR	1,384	1.16	$2.92	35.8	$167,826
> 6 to ≤ 12	DMNFR	718				
Subtotal:		4,311				$167,826
> 0 to < 2	ROS	466				
≥ 2 to < 6	ROS	809	5.74	$2.92	35.8	$485,430
≥ 6 to < 12	ROS	193	1.14	$2.92	35.8	$23,000
Subtotal:		1,468				508,430
					Total:	**$676,256**

Table 21 summarizes the estimated costs from increasing the frequency of LDAR at well production facilities. The overall cost is estimated at about $4.4 million dollars.

Table 21: Well Production Facility –Net Leak Inspection and Repair Costs

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Total Annual Inspection Cost (Contractor)	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
> 0 to < 1	DMNFR				

Table 21: Well Production Facility –Net Leak Inspection and Repair Costs					
Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Total Annual Inspection Cost (Contractor)	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≥1 to <2 tpy	DMNFR				
≥ 2 to ≤ 6	DMNFR	$1,198,821	$1,535,216	$167,826	$2,566,211
> 6 to ≤ 12	DMNFR				
	Subtotal:	$1,198,821	$1,535,216	$167,826	$2,566,211
> 0 to < 2	ROS				
≥ 2 to < 6	ROS	$1,470,438	$582,092	$485,430	$1,567,100
≥ 6 to < 12	ROS	$175,398	$138,867	$23,000	$291,265
	Subtotal:	$1,645,836	$720,959	$508,430	$1,858,365
	Total:	**$2,844,657**	**$2,256,175**	**$676,256**	**$4,424,576**

The estimated emission reductions from increasing the frequency of LDAR at well production facilities is about 2,306 tpy of VOC and 4,164 tpy of methane/ethane.

Table 22: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Facilities	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Fugitive VOC Emissions Reduction for each facility (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each facility (tpy)	Total Methane-Ethane Reduction (tpy)
DMNFR						
> 0 to < 1	1,294					
≥1 to <2 tpy	915					
≥ 2 to < 6	1,384	10%	0.46	636.6	0.70	968.8
≥ 6 to < 12	717					

Subtotal:	4,311			636.6		968.8
ROS						
> 0 to < 2	466					
≥ 2 to < 6	809	50%	1.97	1,593.7	3.77	3,049.9
≥ 6 to < 12	193	10%	0.39	75.3	0.75	144.8
Subtotal:	1,468			1,669.0		3,194.7
			Total:	**2,305.6**		**4,163.5**

Based on these reductions, Table 23 summarizes the cost effectiveness of conducting ongoing instrument based inspections at well production facilities to be about $1,919/ton VOC and $1,063/ton methane/ethane.

Table 23: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Tanks	Total Net Annual Leak Inspection & Repair Cost	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost ($/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost ($/ton)
DMNFR							
> 0 to < 1	1,294						
≥1 to <2 tpy	915						
≥ 2 to ≤ 6	1,384	$2,566,211	10%	636.6	$4,031	968.8	$2,649
> 6 to ≤ 12	718						
Subtotal:	4,311	$2,566,211		636.6	$4,031	968.8	$2,649
ROS							
> 0 to < 2	466						
≥ 2 to < 6	809	$1,567,100	50%	1,593.7	$983	3,049.9	$514
≥ 6 to < 12	193	$291,265	10%	75.3	$3,868	144.8	$2,011
Subtotal:	1,468	$1,858,365		1,669.0	$1,113	3,194.7	$582
	Total:	**$4,424,576**		**2,305.6**	**$1,919**	**4,163.5**	**$1,063**

The Division received field gas sample data from the Colorado Oil and Gas Association (COGA) suggesting a lower field gas VOC content for 6 well production facilities (about 7.9%) and 6 compressor stations (about 8.6%). COGA recommended the Division use this data in the final EIA LDAR analysis for the ROS. In the initial EIA, the Division used producer submitted APEN Form 203 data that showed an average 20.3% VOC content (based on 20 samples) for well production facilities and 14.6% VOC content (based on 12 samples) for compressor stations to estimate the ROS facility fugitive emissions.

Unfortunately the Division is unable to use the COGA information because insufficient supporting documentation was provided on the well production facility location, gas sample gathering location, laboratory conducting the analysis and there were only a limited number of samples.

B. ***Increase the LDAR inspection frequency from annual to semi-annual for compressor stations outside the DMNFR with actual VOC emissions > 0 tpy to ≤ 12 tpy.***

For the DMNFR, all compressor stations must conduct quarterly LDAR inspections. Thus, only compressor stations < 12 tpy outside the DMNFR need to increase inspection frequency to semi-annual.

The Division determined there are a total of 238 compressor stations[20] in the state based on operator provided LDAR reports, which also include inspection frequency. The estimated number of compressor stations in the ROS is based on subtracting the known number of DMNFR compressors stations[21] that were identified through Pneumatic Controller Task Force. Based on the estimated compressor station inspection time estimates in Table 17, the Division estimates the total cost of conducting LDAR inspections is about $141,659 dollars.

Table 24: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Change in Annual Inspection Frequency	Time per IR Camera Inspection (hours)	Total Annual Inspection Time (hours)	Total Annual Inspection Cost
≤ 12 tpy	86	1	11.6	997.6	$141,659
>12 to ≤ 50 tpy	91				
> 50 tpy	11				
Total:	188			997.6	$141,659

The repair costs associated with these inspections are set forth in Table 25 and fuel savings associated with these repairs are set forth in Table 26.

[20] The total number of compressor stations statewide excludes 2 compressor stations in the DMNFR that use compressed air to drive pneumatic devices.
[21] The total number of compressor stations in the DMNFR NAA is 50, but 2 compressor stations that use compressed air to drive pneumatic devices are excluded.

Table 25: Compressor Station Leak Repair Costs				
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Leak Repair Rate ($/hr)	Total Leak Repair Time per Compressor Station (hours)	Total Annual Repair Cost
≤ 12 tpy	86	$74.95	32.6	$210,130
>12 to ≤ 50 tpy	91			
> 50 tpy	11			
Total:	188			$210,130

Table 26: Compressor Station Recovered Natural Gas Value from Leak Repairs					
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Recovered Natural Gas per Compressor Station (tons/year)	Value of Natural Gas ($/MCF)	Conversion Factor (MCF/ton)	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	86	2.93	$2.92	35.8	$26,341
>12 to ≤ 50 tpy	91				
> 50 tpy	11				
Total:	188				$26,341

The total net costs for compressor station LDAR are set forth in Table 28.

Table 27: Compressor Station Net Leak Inspection and Repair Costs					
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≤ 12 tpy	86	$141,659	$210,130	$26,341	$325,448
>12 to ≤ 50 tpy	91				
> 50 tpy	11		-	-	-
	Total:	$141,659	$210,130	$26,341	$325,448

The estimated emission reductions from increasing the frequency of LDAR at compressor stations in the ROS is about 78.3 tpy of VOC and 173.7 tpy of methane/ethane.

Table 28: Compressor Station Leak Inspection Emission Reductions						
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Incremental LDAR Program Reduction % (annual to semi-annual)	Fugitive VOC Emissions Reduction for each CS (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each CS (tpy)	Total Methane-Ethane Reduction (tpy)
≤ 12 tpy	86	10%	0.91	78.30	2.02	173.70
>12 to ≤ 50 tpy	91					
> 50 tpy	11					
			Totals:	**78.30**		**173.70**

Based on these reductions, Table 29 summarizes the cost effectiveness of conducting ongoing instrument based inspections at compressor stations to be about $4,156/ton VOC and $1,874/ton methane/ethane.

Table 29: Compressor Station Leak Cost-Effectiveness Using IR Camera/Method 21							
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Comp. Stations	Total Net Annual Leak Inspection & Repair Cost	Incremental LDAR Program Reduction % (annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost ($/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost ($/ton)
≤ 12 tpy	86	$325,448	10%	78.3	$4,156	173.7	$1,874
>12 to ≤ 50 tpy	91						
> 50 tpy	11						
	Totals:	**$325,448**		**78.3**	**$4,156**	**173.7**	**$1,874**

III. Natural gas-driven pneumatic controllers

The Division is proposing to expand the current pneumatic controller inspection and enhanced response program applicable in the DMNFR to owners or operators of natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations statewide. Under the proposed revisions, owners or operators of natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the ROS must inspect their pneumatic controllers for proper operation during their LDAR approved instrument monitoring method (AIMM) inspections (i.e., with IR camera or EPA Method 21).

The Division estimates there are approximately 2,600 well production facilities and 190 natural gas compressor stations in the ROS that may now have to inspect their pneumatic controllers for proper operation. Based on data collected by the Pneumatic Controller Task Force (PCTF) at two natural gas compressor stations in the DMNFR[22], compressor stations have an average of 11 natural gas-driven pneumatic controllers. The PCTF also collected data on the number of natural gas-driven pneumatic controllers at well production facilities[23] and determined averages based on the barrel per day (bbl/day) production of the facility. Well production facilities producing greater than or equal to 250 bbl/day had an average of 98 natural gas-driven pneumatic controllers per facility. Well production facilities producing greater than or equal to 10 bbl/day but less than 250 bbl/day had an average of 34 natural gas-driven pneumatic controllers per facility. Well production facilities producing greater than or equal to zero bbl/day but less than 10 bbl/day had an average of 9 natural gas-driven pneumatic controllers per facility. Looking at the COGCC's 2018 annual production data, the Division estimates that there are 5 facilities in the counties completely outside of the DMNFR with production greater than or equal to 250 bbl/day, 569 facilities with production greater than or equal to 10 bbl/day but less than 250 bbl/day, and 17,061 facilities with production greater than or equal to zero bbl/day but less than 10 bbl/day, resulting in an estimate of 173,385 natural gas-driven pneumatic controllers at well production facilities in counties wholly outside of the DMNFR. This pneumatic controller estimate is based on average estimates of pneumatic controllers at operations in the DMNFR, and developed through the PCTF study. The Division requests that owners or operators of natural gas-driven pneumatic controllers outside of the DMNFR provide data on the number of natural gas-driven pneumatic controllers at their facilities.

The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their well production facility and natural gas compressor station LDAR programs. Therefore, the Division believes that the inspection and recordkeeping costs are likely minimal.

There may also be costs related to activities necessary to return a pneumatic controller to proper operation. In 2017, the Division considered information from pneumatic controller manufacturers about pneumatic controller repair options and potential emission reductions data in EPA's Oil and Gas CTG, NSPS OOOOa TSD, and Natural Gas Star Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry to determine that returning

[22] See Division Pneumatic Controller Task Force presentation to the Air Quality Control Commission (February 21, 2019) at https://drive.google.com/drive/folders/13Wy4shXktxtR--UjW6XMbQZm-67bLYGD.
[23] Id.

pneumatic controllers to proper operation was cost-effective. The PCTF continues to gather data related to the costs of inspections and repair.[24] Preliminary data indicates that the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to $600 per facility per year. The Division requested that owners or operators of natural gas-driven pneumatic controllers provide Colorado specific cost information concerning the proposed revisions and has not yet received such data.

IV. Storage Tank Automatic Tank Gauging and Truck Loadout

A. Automatic Tank Gauging

The Division is proposing to require the owners or operators of new facilities and certain storage tanks use an automatic tank gauging system to measure and sample (i.e. gauge) the liquid in the storage tank, which will reduce emissions resulting from blowing down the tank and opening the thief hatch to gauge the tank. Based on the Division's permitting inventory, the Division estimates that from 2016 through 2018 an average of 140 well production facilities per year received permits for this process. It is unknown how many new facilities install automatic tank gauging systems either voluntarily or due to permit or other requirements (e.g. compliance orders). Costs related to an automatic tank gauging system may include the gauge, temperature and water level sensors, control panels, transmitters, and management software. The American Petroleum Institute (API) has published the Manual of Petroleum Measurement Standards Chapter 18.2 Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods (July 2016), which provides standards for sampling, temperature determination, calculating volume, and quality testing during custody transfer of crude oil from tanks to a transport vehicle without requiring direct access to the tank thief hatch.

An operator could also install a lease automated custody transfer (LACT) unit that provides for the automatic measurement, sampling, and transfer of liquids. LACT units can be used at facilities that unload liquids to a transport truck as well as facilities that transfer liquids directly to a pipeline. In addition to reducing emissions resulting from opening the thief hatch, facilities that use a LACT unit prior to transfer to a pipeline also reduce emissions from vehicle traffic related to storage tank unloading and emissions from decreased flare combustion. For this EIA, the Division has not been able to quantify these co-benefits (i.e. the reduced NOx from vehicle traffic and avoided combustion), and requests information from stakeholders.

The Division has received some limited information from operators currently using an automatic tank gauging system as a result of a compliance order. The

[24] The PCTF will make any recommendations on its findings in a report to the Commission, due May 1, 2020.

Division has reviewed cost and emission estimates from these operators, with data varying based on cost and emission calculation methodologies. Estimates of emissions reduced from using an automatic tank gauging system to monitor and sample liquids, thereby eliminating emissions from opening the thief hatch, vary by facility and operation. A tank must be blown-down (i.e., gas is vented) before opening the thief hatch to gauge the tank. Assuming VOC emissions of 0.0011 tons per blow down event (which the Division believes is a low estimate and may vary based on the tank level, pressure, temperature, etc) and 100 blow-down events per year (which again, is a low figure), emission estimates include a 0.28 tpy VOC reduction per tank system by using an automatic tank gauging system. Estimates range from 0 to 4.91 tons of VOC emissions reduced, based on the amount of production loaded out during auto-gauging when thief hatches would otherwise have been open. Estimates range from $29,180 to $66,500 per system, reducing emissions by 55.2 tons for all systems installed. Estimates from the use of LACT units ($350,000 initial and $800 monthly) or auto-gauging systems ($17,000 initial and $100 monthly) range $2,120 to $7,094 cost per ton of VOC reduced. Other estimates provided concerning the use of LACT units reflected an average 2.8 tons of VOC reduced from a system costing on average $1,693,256 and an average 3.46 tons from a system costing an average $1,265,774. As far as the Division is aware, none of these cost estimates took into account the savings from manual gauging errors.

Equipment costs will likely be less for owners or operators who already use automatic gauging systems at other facilities. In addition, automatic gauging systems and LACT units offer an increased level of accuracy, which will payback over time.[25] Emission reductions will depend on how frequently the storage tank is gauged or sampled. There may also be costs due to associated recordkeeping requirements, though the Division's proposal is minimal.

B. Truck Loadout of Hydrocarbon Liquids

The Division is proposing to require owners or operators of hydrocarbon liquid storage tanks with uncontrolled actual VOC emissions greater than or equal to 2 tpy control emissions from the loadout of hydrocarbon liquids from the storage tank into a transport vehicle. Owners or operators must use submerged fill and may use either a vapor collection and return system, air pollution control equipment, or both to control emissions. The Division estimates there are approximately 3,600 storage tanks with emissions greater than or equal to two tpy. The Division also estimates an average of 140 new well production facilities per year, and assumes that all storage tanks will have emissions greater than or equal to two tpy. Based on COGCC's 2018 annual production data (355,697,624 barrels of oil produced) and assuming that all production was loaded to a transport vehicle instead of to a pipeline, the Division estimates

[25] See Best Practices for Custody Transfer Using API MPMS 18.2 (October 2017), https://www.emerson.com/documents/automation/white-paper-best-practices-for-custody-transfer-rosemount-en-1730756.pdf.

that loadout emissions range from 18,496 to 41,972 tpy (0.104 lb VOC/bbl crude oil loaded and 0.236 lb VOC/bbl condensate loaded[26]). This is an overestimate as some facilities direct some, if not most, of the product to a pipeline instead of a transport vehicle (although even at those facilities, for example, LACT units can be out of service and operators will need to loadout by truck). In the 2017 oil and gas area source inventory, the Division estimated that emissions from truck loadout of condensate liquid in the DMNFR was 7.5 tons per day (tpd) (2,737 tpy).

Loadout emissions calculations vary based on the hydrocarbon liquid being loaded into the transport vehicle. Using the Division's default emission factor for condensate loadout, the estimated emission reductions anticipated per tank from a 95% loadout control requirement are listed in Table 30 below. Instead of relating loadout emissions to storage tank emissions, Table 30 uses throughput to estimate potential emission reductions. Further, the Division acknowledges that the default emission factors were developed for gasoline transport trucks loading from dedicated loading racks at refineries. Thus, these emissions estimates do not include emission sources such as the blow-down of the tank or from the opening of the thief hatch, and as a result, the loadout emissions may actually be higher.

Table 30: Estimated loadout uncontrolled emissions and potential emission reductions, per tank battery

Storage tank throughput (bbl/yr)	Loadout uncontrolled emissions (tpy)	Loadout emissions controlled at 95% (tpy)	Estimated VOC reduction from loadout control (tpy)
2,000	0.24	0.01	0,22
10,000	1.18	0.06	1.12
20,000	2.36	0.12	2.24
30,000	3.54	0.18	3.36
40,000	4.72	0.24	4.48
50,000	5.90	0.30	5.61

Costs will also vary, depending on facility configuration and control system installed. EPA estimates the cost of purchasing additional connections to route a transport vehicle vent to a useful outlet at $1,000 (estimated implementation cost) and additional operating costs to connect the lines at $200 (incremental operating cost).[27] EPA also estimates that recovering these vapors can payback in two years depending on the frequency of loading, load volumes, and the

[26] See APCD PS Memo 14-02: Oil and Gas Industry Hydrocarbon Liquid Loadout General Permit GP-07 Regulatory Definitions and Permitting Guidance.
[27] EPA Natural Gas Star – Recover Gas During Condensate Loading (2011) at https://www.epa.gov/sites/production/files/2016-06/documents/recyclelinerecovers.pdf.

value of the gas.[28] In most cases, the storage tank will already be controlled as required by the Regulation Number 7 storage tank control programs; therefore, the additional costs to control the transport vehicle emissions may only be related to the installation of vapor return lines to the storage tank such that transport vehicle emissions are then routed to the existing control device. Under the proposed storage tank revisions described above, all storage tanks statewide with uncontrolled actual emission equal to or greater than two tpy must control emissions. However, some operators may choose to install a air pollution control system dedicated to controlling the loadout process, which would have increased costs, though this scenario is not likely for new facilities. The Division is continuing to assess other appropriate applicability thresholds. Lastly, there may be costs associated with the equipment inspection and recordkeeping requirements.

The Division has reviewed cost and emission estimates from several operators, with data varying based on the costs of systems and equipment installed and emission calculations. Estimates provided by operators range from 0.48 to 21.94 tons of VOC emissions reduced, based on the production after the truck loading controls were implemented. Other estimates range from 0.8 to 2.47 tons of VOC emissions reduced, with a loadout system costing $11,250. Estimates for dedicated air pollution control equipment range from $48,500 to $45,000 per loadout control system, with commensurate reduction in loadout emissions of 195 tpy (95% control). Yet other cost estimates range from $12,200 to $14,000 per system, with emission reductions of 25.95 tons VOC. And, other estimates from tank loadout controls ($15,000 each system) range $7,333 to $8,420 cost per ton of VOC reduced.

The Division requested that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions. The Division has received some such information from industry and continues to evaluate and discuss both the automatic tank gauging and truck loadout proposed requirements.

Industry provided cost information based on three potential loadout control scenarios: (1) the addition of a vapor line to existing infrastructure without requiring vapor control system upgrades or updates; (2) the addition of a vapor line to existing infrastructure and requiring vapor control system upgrades or updates; and (3) the addition of a dedicated loadout control system. Industry provided a range of costs for each scenario, as listed in the table below. Additionally, industry identified the likely percentage of facilities that would full under each scenario.

[28] Id.

Table 31: Industry provided loadout control system cost estimates

Scenario	Capital cost	Annual maintenance cost	Percentage of facilities
1	$3,000-$29,000	$1,000-$5,000	50%
2	$11,000-$34,000	$2,800-$3,600	12%
3	$21,000-$83,000	$1,500-$8,600	38%

Using the average of the estimated capital and annual costs, amortized over five years, the cost per ton of VOC reduced is listed in the table below. Using the industry cost estimates, the Division believes that controlling loadout emissions is generally cost-effective.

Table 32: Estimated cost per ton to control loadout emissions

Annual throughput (bbl/yr)		2,000	10,000	20,000	30,000	40,000	50,000
Annual VOC emission reduction (tpy)		0.22	1.12	2.24	3.36	4.48	5.61
Scenario	Average annual cost	Cost of emission control per ton of VOC reduced per annual throughput category ($/tpy VOC)					
		2,000	10,000	20,000	30,000	40,000	50,000
1	$6,200	$28,182	$5,536	$2,768	$1,845	$1,384	$1,105
2	$7,700	$35,000	$6,875	$3,438	$2,292	$1,719	$1,373
3	$14,550	$66,136	$12,991	$6,496	$4,330	$3,248	$2,594

The Division continues to evaluate and discuss both the automatic tank gauging and truck loadout proposed requirements.

V. Well Emissions

The Division is proposing to expand the current requirement for owners or operators to use best management practices (BMPs) to minimize emissions associated with well maintenance and liquids unloading to also require operators use BMPs to minimize emissions associated with well plugging activities. During the plugging of a well, emissions may be released from the well to the atmosphere.

According to COGCC data, from 2016 through 2018, an average of 1,854 wells per year were plugged and abandoned. Due to the variability of BMPs that could be employed to minimize emissions, the specific costs and quantity of emissions that will be reduced by the proposed revision are unknown. Because the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

The Division is also proposing additional recordkeeping and reporting requirements. There is uncertainty around the emissions from these activities as well as when and which BMPs may be used to minimize emissions. There may be additional costs in maintaining records and submitting reports to the Division. The additional records and report will address some of these uncertainties and inform potential, future emission reduction strategies.

The Division requested that owners or operators of potentially impacted oil and gas wells provide Colorado specific cost information concerning the proposed revisions but did not receive such cost information.

VI. Downstream Transmission

The Division is proposing a new performance based program for the downstream transmission segment, as a result of a recommendation from the SHER team. The downstream transmission segment includes pipelines, compressor stations, aboveground and underground storage facilities, and other equipment transporting or storing natural gas downstream of the natural gas processing plant and prior to the natural gas distribution segment. In Colorado, this segment consists of six owners or operators operating 56 facilities and miles of pipelines. Under the proposed program, a Steering Committee will be established to develop a methane emissions intensity target and evaluate progress against this target. Additionally, downstream transmission owners or operators will begin implementing company specific best management practices (BMP) plans in 2021; begin gathering emissions data in 2021, which will be used to establish the segment methane emissions intensity target; and achieve the segment methane emissions intensity target by 2025. Due to the variability of BMPs that could be employed to reduce emissions from these operations, the specific costs and quantity of emissions that will be reduced by the proposed revision are unknown. There will be additional costs associated with participating on the Steering Committee and compiling data through a third party contractor selected and funded by the transmission segment. There will also be costs related to data collection and associated recordkeeping and reporting requirements.

The Division requested that owners or operators of downstream transmission facilities and other SHER team participants provide cost information concerning the proposed revisions but did not receive such cost information. The Division has, however, continued to work with the SHER team participants to finalize the proposed regulatory and statement of basis language.

VII. Oil and Gas Sector – Annual Emissions Inventory

The Division is proposing an annual emissions inventory program for the oil and gas sector. Under the proposed inventory program, owners or operators of oil and gas operations and equipment will collect VOC, NOx, carbon dioxide (CO), methane, and ethane emissions data and submit an annual report to the Division. These reports may be partially duplicative of current air pollutant emissions notice (APEN) requirements. However, these reports may partially offset future information requests made by the Division to inform emission inventory development for ozone and other modeling efforts and measuring progress against new greenhouse gas reporting requirements of associated with Senate Bill 19-096 and House Bill 19-1261. The Division intends to consider in future rulemakings how to streamline these related reporting regimes. There will be costs related to data collection and associated recordkeeping and reporting requirements.

The Division requested that owners or operators of engines, drilling operations, well production facilities, natural gas compressor stations, and downstream transmission operations provide cost information concerning the proposed revisions but did not receive such cost information. The Division continues, however, to work with stakeholders to draft an appropriate and effective emissions inventory program.

VIII. Serious Area RACT Requirements for Major Sources

The Division expects that EPA will reclassify the DMNFR as a serious ozone nonattainment area in late 2019. As a Serious nonattainment area, Colorado must revise its ozone SIP to include, among other things, provisions that provide for the implementation of RACT for each category of VOC sources covered by a CTG, for which Colorado has sources, and all other major stationary sources of VOC or NOx located in the DMNFR area. Under a Serious nonattainment area classification, major sources are sources that emit or have the potential to emit greater than or equal to 50 tons per year of NOx and/or VOC.

The Division analyzed 31 major sources (≥ 50 tpy VOC or NOx) in the DMNFR. The Division did not analyze oil and gas sources with emissions between 50 and 100 tpy as these sources are subject to the requirements adopted in 2017 that correspond to EPA's Oil and Gas CTG and engine and other combustion equipment requirements in Regulation Number 7. The 31 sources are subject to various and numerous Regulation Number 7 RACT, RACT/beyond RACT/BACT, or NSPS or NESHAP requirements. However, while these requirements are included in federally enforceable permits and NSPS and NESHAP, some of the requirements are not currently included in Colorado's SIP, as is required for a Serious nonattainment area.

Therefore, the Division is proposing to revise Regulation Number 7 to include requirements for general solvent use, to expand the combustion equipment requirements, to incorporate by reference specific NSPS or NESHAP requirements, and to require specific sources to submit a RACT analysis concerning the facility or specific point(s) to the Division.

A. Solvents

The Division is proposing to define RACT on a categorical basis for general solvent use operations. The proposed revisions would broadly apply to sources with a potential to emit 50 tons per year of VOC and whose solvent use emissions trigger permitting thresholds (i.e., 2 tons per year VOC on an uncontrolled actual basis in the ozone nonattainment area, or 5 tons per year in the rest of the state). At these thresholds, new work practice standards apply requiring that containers be covered, proper disposal of solvent waste, and use good air pollution practices (e.g., the use of low/no VOC solvent if possible, using only amounts needed, submerged fill pipes, closed loop systems, maintaining operations to be leak free). Additionally, in the DMNFR, if an applicable source's solvent use operations have 25 tons per year VOC emissions on an uncontrolled actual basis, emissions must be reduced by 90% and additional control requirements, monitoring, performance testing, and recordkeeping requirements for general solvent use operations apply. The Division has identified at least two facilities in the DMNFR that may be subject to this proposal and believes there are likely other sources that may be subject, including marijuana and hemp solvent extraction facilities. There are potential costs related to all of these elements.

The Division requested that owners or operators of equipment or activities that may be subject to these provisions provide cost information concerning the proposed revisions but did not receive such cost information.

B. Combustion Equipment

The Division is proposing to expand the combustion equipment requirements for boilers, turbines, and engines that the AQCC adopted in 2018 for sources with emissions greater than or equal to 100 tpy of NOx to sources with emissions greater than or equal to 50 tpy of NOx.

1. Boilers

The categorical RACT requirements for boilers include an emission limit of 0.2 lb/MMBtu, associated monitoring and recordkeeping, and combustion process adjustment (tuning). The Division is proposing to lower the MMBtu/hr applicability for these boilers from 100 MMBtu/hr to 50 MMBtu/hr. The Division is also proposing to require only initial and periodic performance testing for these boilers instead of continuous emission monitoring systems (CEMS).

There are 24 boilers that may be subject to this categorical RACT standard. There are 10 boilers below the heat input applicability threshold of 50 MMBtu/hr that are subject to the combustion process adjustment requirements but not the numerical standard.

There are 14 boilers with a design heat input rating greater than or equal to 50 MMBtu/hr that are potentially subject to the categorical RACT standard. The Division is not proposing to revise the low utilization capacity factor exemption and an owner could maintain the operation of a boiler below the capacity factor, which would exempt the boiler from the numerical standard. Such boilers would then only be subject to minimal recordkeeping requirements. For boilers subject to the numerical limit, the Division is proposing a periodic performance test requirement to ensure compliance with the limit. In developing the monitoring requirements for boilers at sources with NOx emissions greater than or equal to 100 tpy, the Division estimated that the cost for the installation, operation, and maintenance of a CEMS device range from approximately $150,000 to $200,000 (capital cost) and $26,000 to $49,000 (annual cost).[29] In contrast, for boilers at sources with NOx emissions greater than or equal to 50 tpy, the Division estimates the cost of a performance test at approximately $4,000 to $8,000 per test, depending on the contractor fee schedules and location with response to the source. These tests will be required every two years. Additional costs include costs related to the associated recordkeeping requirements. In addition, these boilers will be subject to period combustion process adjustment requirements.

2. Turbines

The categorical RACT requirements for turbines include compliance with NSPS GG for turbines constructed on or before February 18, 2005, and compliance with NSPS KKKK for turbines constructed after February 18, 2005, as well as associated monitoring and recordkeeping requirements.

There are 8 turbines that may be subject to this categorical RACT standard. The Division believes the direct economic impact to owners or operators of affected turbines to be negligible since these turbines are already required to meet the limits and monitoring requirements of the applicable NSPS provisions.

3. Engines

The categorical RACT requirements for engines include an emission limit of 9.0 g/bhp-hr for compression ignition engines with a maximum design power output greater than or equal to 500 hp. Engines that operator at less than 10% of the capacity factor are exempt from the numerical emission limit.

[29] See July 19, 2018, AQCC rulemaking hearing establishing RACT for combustion equipment.

There are 17 engines that may be subject to this categorical RACT standard. As most of these engines are backup or emergency generators, the Division anticipates that the economic impact of the proposal on owners and operators will be negligible since the engines are likely to operator under the capacity factor exemption and therefore be subject to minimal recordkeeping requirements. However, the engines may continue to be subject to the combustion process adjustment requirements, applicable to engines with uncontrolled actual emissions greater than or equal to 5 tpy.

4. Kilns, dryers, furnaces

The categorical RACT requirements for kilns, dryers, and furnaces currently apply to lightweight aggregate kilns and process heaters. Therefore, the Division is proposing to expand the combustion process adjustment requirements to ceramic kilns, dryers, and furnaces.

There are five facilities that may be subject to this proposed requirement, with kilns ranging from 0.9 MMBtu/hr to 10 MMBtu/hr, dryers ranging from 3 MMBtu/hr to 44.1 MMBtu/hr, and furnaces ranging from 17 MMBtu/hr to 32 MMBtu/hr. There may be costs where the owner is not currently conducting a regulatory, voluntary, or manufacturer specified tuning or combustion adjustment due to the time to conduct the adjustment and potential costs of any necessary replacement equipment components.

The Division requested that owners or operators or equipment or activities that may be subject to these provisions provide cost information concerning the proposed revisions but did not receive such cost information. The Division has, however, worked with stakeholders to refine the combustion equipment requirements for ceramic kilns.

C. Incorporation By Reference of NSPS/NESHAP

The Division proposes to include RACT requirements through incorporating by reference certain NSPS and/or NESHAP requirements for specific sources. There may be costs for sources associated with including these RACT requirements in the SIP due to the process and timeframe for a source seeking to amend an EPA approved SIP provision. However, incorporating NSPS or NESHAP requirements for these specific sources does not add additional implementation costs because these requirements are already federally enforceable.

D. Requirements for RACT Analysis Submittal

The Division proposes to require owners or operators of some major sources or specific points at major sources to submit a RACT analysis concerning the facility or specific point(s) to the Division. The proposed revisions may involve costs related to developing the RACT analyses and potential costs related to resulting emission reduction controls or measures.

The Division requested that owners or operators of potentially subject boilers, turbines, engines, or kilns provide cost information concerning the proposed revisions but did not receive such cost information.

IX. Gasoline transport trucks, testing facilities, terminals, and service stations

The Division is proposing to update and streamline the requirements for gasoline transport truck testing and vapor systems.

The Division processes 2,500 to 3,000 gasoline transport truck vapor integrity certifications per year. These gasoline transport trucks must be vacuum-pressure tested annually. There are seven testing facilities. The Division is proposing to update the vacuum-pressure test in Regulation 7 with the more current EPA Method 27 test method. EPA Method 27 is the required test method in EPA's NSPS and NESHAP for bulk terminals and gasoline dispensing facilities. Under the proposed revisions, the owners or operators of gasoline transport trucks must conduct this annual test using EPA's Method 27 and maintain records associated with the EPA Method 27 test.

There are approximately 40 bulk terminals in the DMNFR, six of which are large volume bulk terminals. Under the proposed revisions, the terminal operators must ensure that the gasoline transport trucks filled at the terminal have been tested annually according to EPA Method 27.

There are approximately 2,200 service stations in the DMNFR. The Division is proposing to clarify that the service stations must ensure that petroleum liquids are transferred using a properly maintained, functioning, and leak-tight vapor system.

The Division's proposed revisions clarify the vapor systems standards and update the test requirements and associated records to align with the current federal standards. Therefore, the Division believes that the cost impacts will be minimal or even reduced due to the removal of the requirement for the Division to provide and gasoline transport truck owners or operators to apply the certification sticker. Further, there may be cost savings in streamlining conflicting requirements in the SIP and associated with EPA's Method 27 and federal rules.

The Division requested that owners or operators of gasoline transport trucks, bulk terminals, or service stations provide Colorado specific cost information concerning the proposed revisions but did not receive such cost information.

SUMMARY AND CONCLUSION

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

The Division has determined that there may be costs related to the proposed revisions potentially impacting owner or operators of oil and gas operations including costs related to additional LDAR inspections, responsive actions, recordkeeping, and reporting; costs related to controlling and inspecting additional storage tanks; costs related to inspecting additional pneumatic controllers, as well as associated recordkeeping and reporting; costs related to installing automatic storage tank gauging systems at new facilities; costs related to controlling emissions from storage tank loadout activities; costs related to the use of best management practices to minimize well emissions, and associated recordkeeping and reporting; costs related to the downstream transmission segment performance based program; and costs related to an annual emissions inventory program. Based on the information reasonably available to the Division, the Division projects that the proposal will reduce VOC emissions in Colorado by approximately 5,766 tpy and will result in reductions of methane/ethane by approximately 4,337 per year, with a cost of $10.5 million/year. The calculated cost per ton of VOC reduced ranges from $923 to $4,156 per ton. The overall cost effectiveness for the package is approximately $1,821 per ton of VOC reduced.

The Division has determined that there may be costs related to the proposed revisions potentially impacting major sources (≥ 50 tpy VOC and/or NOx) in the DMNFR. There may be economic impacts of the proposed solvent use control and work practices should owners or operators of operations that use solvents have to change work practices or solvent use. There may be economic impacts of the proposed revisions expanding the combustion equipment standards should owners or operators have to conduct additional performance testing, combustion process adjustments, or recordkeeping. The Division has determined there may be costs related to developing RACT analyses for specified major sources. However, the specific potential costs are unknown due to the range of industries impacted and the varied number of emission NOx and VOC emission points at these major sources.

The Division has also determined that there may be costs related to the proposed revisions potentially impacting gasoline transport trucks, truck testing facilities, terminals, and service stations. However, the proposed revisions update and align with current federal standards; therefore, the Division believes that the costs impact will be minimal or even reduced.

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 requested that affected industry or any interested party submit information with regard to the cost of compliance with these proposed rule revisions. Where the Division received such information, the Division continues to evaluate and discuss the proposed requirements.