Regulatory Analysis

In performing a regulatory analysis, each rulemaking entity must provide the information requested for the regulatory analysis to be considered a good faith effort. Each regulatory analysis shall include quantification of the data to the extent practicable and shall take account of both short-term and long-term consequences. The regulatory analysis must be submitted to the Air Quality Control Commission Office at least five (5) days before the administrative hearing on the proposed rule and posted on your agency's web site. For all questions, please attach all underlying data that supports the statements stated in this regulatory analysis.

Department: Colorado Department of Public Health & Environment

Agency: Air Quality Control Commission

CCR: 5 CCR 1001-9

Date: 9/11/2020

Rule Title or Subject:

Regulation Number 7
Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions

I. Introduction

On July 15, 2020, the Colorado Oil and Gas Association (COGA) and American Petroleum Institute – Colorado (API) filed a Request for Issuance of a Cost-Benefit Analysis and Regulatory Analysis for Proposed Provisions in the matter of revisions to Regulation Number 7, with the Colorado Air Pollution Control Division (Division), per C.R.S §§24-4-103(2.5) and (4.5)(a), and the Air Quality Control Commission (Commission) procedural rules, 5 Code Colo. Reg. §1001-1:1.5.5(12). This document satisfies the requirements for a Regulatory Analysis, and is separate from the related Cost-Benefit Analysis. Similarly, this Regulatory Analysis is different from, but related to, the required Economic Impact Analysis, C.R.S. §25-7-110.5(4).

The State Administrative Procedure Act (APA), §24-4-101, C.R.S. et seq., serves as the legal authority for this rule-making process, and it sets forth requirements for both cost-benefit and regulatory analyses. Under Section 24-4-103 of the APA, any person may request an agency engaged in a rulemaking to prepare a regulatory analysis. The regulatory analysis must include:

- A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule;
- To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons;
- The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues;
- A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;
- A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule; and
- A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.
- To the extent practicable, a quantification of the data used in the analysis, and taking into account both short-term and long-term consequences in the analysis.

The Division is proposing revisions to the Air Quality Control Commission's Regulation Number 7 to address Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations), ozone, the second implementation period of the Regional Haze Rule, and nitrogen deposition at Rocky Mountain National Park (RMNP).

The Division is proposing revisions related to natural gas fired reciprocating internal combustion engines (RICE) that are intended to reduce oxides of nitrogen (NOx) emissions from stationary source engines (not including non-road engines) on a state-wide basis. The Division is proposing a new subpart to Regulation 7, Part E, Section I.D.5., to establish state-only emissions standards for natural gas fired RICE equal to or greater than 1,000 horsepower (HP). These standards will apply to natural gas fired RICE placed in service, modified, or relocated in Colorado. To provide flexibility and help manage overall costs, the Division is proposing to allow company-specific alternate plans to the rule, which will achieve the same or better emission reductions from engines addressed in the plan in the same timeframe that the proposed emission standards would achieve. The Division is also proposing new performance testing, monitoring, recordkeeping, and reporting requirements for affected RICE.

In continuing to address the directives of SB 19-181, the Division is proposing additional revisions to monitor and reduce emissions from oil and gas operations. Specifically, the Division is proposing the following requirements:

- Monitor air quality during pre-production (i.e., drilling through flowback) and early-production well production facilities in a new subpart to Part D, Section VI.;
- Reduce VOC emissions from pre-production tanks and vessels (i.e., flowback vessels) in a new subpart to Part D, Section VI.;
- Expand reporting to include carbon dioxide (CO2) and nitrous oxide (N2O) emissions in Part D, Sections II.G., IV., and V.; and
- Reduce and report emissions from class II disposal well facilities in Part D, Sections II. and V.

These proposed revisions expand upon revisions adopted by the Air Quality Control Commission in December 2019.

This analysis represents information gathered from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where additional data was not reasonably available, the Division utilized assumptions that are set forth in this analysis. This analysis builds upon the Final Economic Impact Analysis (Final EIA) submitted to the Commission on July 30, 2020 and the Cost Benefit Analysis requested by rulemaking parties and submitted to the Department of Regulatory Agencies on September 4, 2020, and provides additional detail as required by statute. The Division incorporates the content of the Final EIA and Cost Benefit Analysis into this Regulatory Analysis. The Division also refers herein to filings by the Division and other parties in this rulemaking proceeding; these materials are available on the Commission's website in the monthly materials folder for the September 17-18, 2020, Commission rulemaking hearing, at: https://drive.google.com/drive/folders/1mbKj54igM_3E3aRxvYqL2yMaQquXYGck?usp=sharing

The analysis below is divided among the individual proposals under Regulation 7 with each of the proposals addressed separately in terms of the Regulatory Analysis requirements.

II. State-only emissions standards for stationary natural gas fired reciprocating internal combustion engines (RICE) with a manufacturer's design rate greater than or equal to 1,000 horsepower (Regulation 7, Part E, Section I.D.5.).

i. A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.

The costs of this proposal will directly affect owners and operators of stationary natural gas fired RICE statewide with a manufacturer's design rate greater than or equal to 1,000 horsepower, all of which are located at oil and gas operations.

The proposal will benefit those companies that manufacture, distribute and/or maintain RICE and emissions control devices/equipment for RICE, companies that provide emissions testing services for RICE, and potentially companies that manufacture, distribute and/or maintain electric-powered alternatives to RICE.

The proposal also broadly benefits all persons in Colorado, especially those who live and work in the proximity of affected RICE under the proposed rule through reduced levels of emissions exposure. The citizens in the Denver-Metro-Northern-Front Range (DMNFR) and Remainder of the State (ROS) will benefit from the proposed rule revisions through reduced NOx, carbon monoxide (CO), volatile organic compound (VOC) and greenhouse gas (GHG) emissions, some of which may contribute to a lowering of ozone levels. Benefits to affected individuals may also include improved visibility in Colorado's Class I Areas, such as Rocky Mountain National Park, and reduced impact of climate-influenced events.

ii. *To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.*

Based on air pollutant emission notice (APEN) data as of July 2019, the Division estimated the number of RICE that would be affected under this proposal in terms of needing some level of emissions control to meet the required standards. The affected RICE are split into three categories: two-stroke lean burn engines (2SLB), four-stroke rich burn engines (4SRB), and four-stroke lean burn engines (4SLB).

As noted in the Final EIA for the proposal, the Division determined there are fourteen (14) 2SLB, seventy-four (74) 4SRB, and one-hundred thirty-five (135) 4SLB RICE statewide that will need emissions control to meet the required standards.[1] Of the 14 2SLB RICE, nine (9) will require less than a 10% emission reduction to meet the standard, four (4) will require a 10-25% emission reduction, and one (1) will be required to reduce emissions by 36% to meet the standard. Of the 74 4SRB RICE, thirty-seven (37) or half will require less than a 10% emission reduction to meet the standard, sixteen (16) will require a 10-25% emission reduction, nine (9) will be required to reduce emissions by 25-50%, and twelve (12) will require a 50-70% emission reduction to meet the standard. Of the 135 4SLB RICE that require additional controls, sixty-four (64) will require at most a 25% emission reduction, while the remaining seventy-one (71) RICE will require a 25-90% emission reduction to meet the standard.

The Division estimated the annualized cumulative control costs for affected RICE under the proposed rule, which includes control equipment or unit upgrade costs, control equipment depreciation costs, operations and maintenance (O&M) costs, and performance testing and portable analyzer testing costs.[2]

The minimum annualized cumulative control cost for each affected 2SLB RICE is $415,698 with an average cost effectiveness ranging from $5,568 - $12,232 per ton of NOx reduced depending on whether initial and/or follow-on unit upgrades are required to meet the standards.[3] The Division estimates that the minimum total annualized cost for all operators with affected 2SLB RICE is about $3,096,535 and the maximum annualized cost is about $6,803,330.

The Division estimates a NOx emission reduction of 556 tons per year (tpy) associated with the proposed emission standards for 2SLB RICE.[4]

The annualized cumulative control cost for each affected 4SRB RICE outside the DMNFR ozone NAA is $13,860 (60 of the 74 affected RICE are located outside the DMNFR ozone NAA[5] The Division estimates that the estimated total annualized cost for all operators with affected 4SRB RICE is about $1,016,855.

The average cost effectiveness is $1,201 per ton of NOx reduced if the 4SRB RICE is located inside the DMNFR ozone NAA and $1,763 per ton of NOx reduced if the 4SRB RICE is located outside the DMNFR ozone NAA.[6]

[1] See Tables 1, 4 and 7, Final EIA
[2] See "Controls for Natural Gas Fired Reciprocating Internal Combustion Engines" in Cost Benefit Analysis, pgs. 5-16
[3] See Tables 2 and 3, Final EIA
[4] See Table 3, Final EIA
[5] See Table 5, Final EIA
[6] See Tables 5 and 6, Final EIA

The Division estimates a NOx emission reduction of 626 tpy associated with the proposed emission standards for 4SRB RICE.[7]

The annualized cumulative control cost for affected 4SLB RICE vary by control option and location of the RICE inside or outside the DMNFR ozone NAA. For air-fuel ratio (AFR) adjustments, the minimum annualized costs are $21,178 (inside NAA) and $21,808 (outside NAA) per 4SLB RICE, which equates to $6,607 (inside NAA) and $7,933 (outside NAA) per ton of NOx reduced. The maximum annualized costs are $35,915 (inside NAA) and $36,545 (outside NAA) per 4SLB RICE, which equates to $13,454 (inside NAA) and $11,073 (outside NAA) per ton of NOx reduced.[8]

For selective catalytic reduction (SCR) for 4SLB RICE, the minimum annualized costs are $92,648 (inside NAA) and $93,278 (outside NAA) per RICE, which equates to $813 (inside NAA) and $12,201 (outside NAA) per ton of NOx reduced. The maximum annualized costs are $274,825 (inside NAA) and $275,455 (outside NAA) per RICE, which equates to $2,411 (inside NAA) and $36,031 (outside NAA) per ton of NOx reduced.[9]

For low emission combustion (LEC) overhaul for 4SLB RICE, the minimum annualized costs are $11,617 (inside NAA) and $12,247 (outside NAA) per RICE, which equates to $102 (inside NAA) and $1,602 (outside NAA) per ton of NOx reduced. The maximum annualized costs are $365,905 (inside NAA) and $366,535 (outside NAA) per RICE, which equates to $3,210 (inside NAA) and $47,944 (outside NAA) per ton of NOx reduced.[10]

The Division estimates that the minimum total annualized cost for all operators with affected 4SLB RICE will range from about $9,252,051 to $32,946,581 (assuming that 50% of operators install SCR and 50% install LEC).

The Division estimates a NOx emission reduction of 1,179 tpy associated with the proposed emission standards for 4SLB RICE.[11]

The Division estimates that the proposed emission standards for all natural gas RICE will reduce NOx emissions state-wide by 2,361 tpy.

For testing costs, COGA provided the Division with estimated costs for conducting performance testing, as well as portable analyzer testing for affected RICE under the proposal. Performance testing is estimated to cost $3,800 per RICE in the DMNFR ozone NAA and $4,400 per RICE in the rest of the state. Portable analyzer testing costs $1,300 per RICE in the DMNFR ozone NAA and $1,900 per RICE in the rest of the state. The higher costs in the rest of the state reflect increased time and fuel for testing personnel to travel to remote sites. The costs associated with preparing test reports should be included in the noted testing costs. Because the Division requires electronic filing of test reports, filing costs for RICE emissions testing records/reports should be minimal to non-existent, particularly if the test report would have to be filed anyway pursuant to a separate existing regulatory or permit requirement.

The Division did not receive any information from the affected industry to suggest that operators would, as a result of these proposed requirements, cease operations at any affected facility at which a subject engine is located, thereby avoiding any resulting downstream and indirect impacts.

iii. The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.

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[7] See Table 6, Final EIA
[8] See Table 9, Final EIA
[9] See Table 10, Final EIA
[10] See Table 11, Final EIA
[11] See Tables 9, 10 and 11, Final EIA

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 and currently anticipated resources. Though the proposal will result in an increased number of permitting actions and associated fees, the Division expects that these provisions will result in a negligible increase in revenues.

iv. A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.

The responses to subsections i. and ii. above identify the costs and benefits of the proposed rule. A primary benefit is the reduction of emissions statewide, including those that are ozone precursors, to help meet the 2008 and 2015 ozone NAAQS for the DMNFR ozone NAA and maintain compliance with those requirements in the ROS. Additionally, attaining the 2008 and 2015 ozone standards will likely result in substantial health benefits. The proposed NOx controls for natural gas RICE also meet the directive to reduce emissions from oil and gas operations required by SB 19-181. Another important benefit is maintaining progress towards requirements under the Regional Haze Rule since ninety percent (90%) of the affected RICE under the Division's proposal are considered to be close enough to a Class I Area to impact visibility. Finally, the proposed rule will benefit RMNP by reducing nitrogen deposition in the park, which is a goal that CDPHE, the U.S. Environmental Protection Agency (EPA), and the National Parks Service agreed to in the 2007 Nitrogen Deposition Reduction Plan.

There are a number of disbenefits to inaction. The first is the potential impact to public health and the environment. Inaction could worsen the DMNFR's ozone problem, which has negative health impacts for affected residents in that area, and could potentially lead to NAAQS violations in the ROS. Further, inaction could jeopardize progress under the Regional Haze Rule resulting in increased visibility degradation in Class I Areas, and impede efforts and commitments made to reduce nitrogen deposition in RMNP. Inaction would also prevent the Division from addressing the requirements of its statutory and federal obligations.

The probable costs of inaction include those associated with the health effects from exposure to ozone, including reduced lung function and damage to lung tissue. Ground level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. EPA's ground-level ozone web page notes, "Ozone can worsen bronchitis, emphysema, and asthma, leading to increased medical care."[12] Further, a continued failure of the DMNFR to attain the ozone standard will result in further control measures that are potentially less cost-effective being imposed upon the oil and gas industry and other sources of ozone precursor emissions. Other costs from inaction include those resulting from continued nitrogen deposition that can alter sensitive ecosystems in places like RMNP.

The benefits of inaction include cost savings for owners and operators of affected RICE under the proposed rule. The costs of inaction outweigh the costs of the Division's proposed rule.

v. A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.

The Division has considered and allowed for a less costly or less intrusive method for achieving the purpose of the proposed rule through the Alternative Company-Wide Compliance Plan (Company-Wide Plan) in the proposal. The Company-Wide Plan allows operators to take a big picture approach to their entire fleet of engines to achieve the same or better emission reductions without necessarily updating or retrofitting each engine, which allows for greater flexibility in achieving the requirements of the proposed rule. Based on information collected by the Division and provided by industry stakeholders, the Division expects the Company-Wide Plan approach to reduce costs to operators while resulting in the same or better expected emissions benefit.

[12] See EPA's Gound-level Ozone Basics at https://www.epa.gov/ground-level-ozone-pollution/ground-level-ozone-basics#wwh

Furthermore, the Division reviewed engine rule limits, standards, and applicable costs where available in preparing the proposed rule, and found multiple areas of the country with similar requirements and reasonable cost demonstrations.

vi. A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.

The Division evaluated several alternative methods for achieving significant NOx emission reductions from RICE in Colorado during development of the proposed rule. Initially, the Division assessed all active, APEN-reportable RICE in Colorado as of July 2019. Grouping the RICE by horsepower, the Division then considered the NOx emission reduction impact of tightening emissions limits on small RICE (less than 100 HP), small-medium RICE (100 to less than 500 HP), medium RICE (500 to less than 1,000 HP) and large RICE (1,000 HP or greater) state-wide. According to the data set, large RICE comprise 52% of actual controlled NOx emissions from all RICE statewide. For comparison, RICE between 100 HP and 1,000 HP comprise 15% of actual controlled NOx emissions statewide from all RICE. Therefore, in terms of achieving the greatest emission reductions, the Division chose to focus on the large RICE subcategory for this particular rulemaking. Furthermore, the large RICE are all operated by the oil and gas industry, which significantly narrowed the scope of the impacted industries for the proposal.

The Division also evaluated different emissions standards for each subcategory of RICE and the potential impact on NOx emissions. The Division reviewed various standards set by other states and determined that using Colorado-specific data based on controlled NOx emissions from RICE subtypes was appropriate for this rulemaking. The Division recommended the proposed emission standards for RICE by working directly with stakeholders, analyzing the impact on the regulated community, and determining the potential NOx emissions reductions that could be achieved with the least incurred cost.

The Division determined that the proposed limits for large 4SRB RICE were appropriate because the Colorado-specific data set showed that controlled rich burn RICE operate at or near these emission rates on average. The analysis showed that the average actual controlled NOx emissions from these RICE are about 0.8 grams per horsepower-hour (g/hp-hr). Since there are well-established, affordable control options with few technical challenges available to meet the proposed limits for 4SRB RICE, most notably non-selective catalytic reduction (NSCR), the Division decided not to recommend a higher limit for these RICE.

The analysis of 4SLB RICE showed that actual controlled NOx emissions from this subcategory averages about 0.94 g/hp-hr. To account for the significant variability in the way these types of RICE operate, the Division added a 25% buffer to the emission rate to establish the proposed NOx limit for 4SLB RICE, which equates to 1.2 g/hp-hr. The Division believes this buffer is appropriate in setting the proposed limit for the 4SLB RICE in Colorado.

The analysis of 2SLB RICE showed actual controlled NOx emissions from these RICE are 1.5 g/hp-hr. Many of the 2SLB RICE are not controlled and there are significant technical constraints associated with potential controls. Therefore, based on Colorado's specific data set, the Division doubled the actual NOx emissions for the proposed limit for 2SLB RICE, which equates to 3.0 g/hp-hr.

The Division also considered requiring mandatory controls for every RICE greater than or equal to 1,000 HP, without an optional company-wide plan. During the proposal development process, the Division recognized, through its own analysis and engagement with stakeholders, that some individual RICE might require very expensive control retrofits to meet the proposed NOx standards. The Division developed the company-wide proposal with stakeholder input to enable the state to achieve the necessary NOx reductions in the most cost effective manner, which is why requiring mandatory controls on all affected RICE was rejected. In the Cost Benefit Analysis, the Division provided cost estimates for a RICE NOx reduction plan without the company-wide proposal. As noted in the analysis, the Division considers individual control retrofits to be cost effective for most engines, but the wide range of potential control retrofit costs suggests that requiring every engine to meet the proposed standards is not always the lowest cost alternative. In some cases, it may be less expensive for operators to replace existing, high-emissions RICE with new, low-emissions engines, or to replace the RICE with an electric motor. As long as the alternative achieves emission reductions that are equal to or greater than installing additional controls on every RICE, the Division encourages owners and operators to select the cost-minimizing approach that provides health and environmental benefits while reducing regulatory compliance cost.

III. Requirements to monitor air quality during pre-production (i.e., drilling through flowback) and early-production well production facilities (Regulation 7, Part D, Section VI.).

i. A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.

The proposal affects the oil and gas industry and supporting businesses in Colorado, specifically those associated with pre-production and early-production operations. Oil and gas companies that drill and produce from new wells will bear the costs of this proposal.

Local governments that receive revenue from oil and gas operations may also be indirectly impacted by the proposed rules, though there is no indication or evidence that this impact is likely to occur as a result of the proposal. Since the Commission adopted significant revisions to Regulation 7, there has been no decrease in drilling activity prior to 2020. In fact, since 2014, drilling activity and associated production has significantly increased in the state. However, this trend may not be reflective of current and future years of drilling and production as oil and gas production in 2020 thus far has been impacted by COVID-19.

The proposed Regulation 7 revisions will benefit companies that manufacture, distribute and/or operate air monitoring technologies or systems and associated equipment needed for such monitoring, such as meteorological devices.

The proposal could also benefit consultants hired by oil and gas companies to develop air quality monitoring plans and/or monitoring reports to be submitted to the Division on behalf of companies.

Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas pre-production and early-production operations, by providing a better understanding of emissions from these operations, which could be used to inform efforts to better address and mitigate such emissions, and improve emissions monitoring. There is also the likelihood that emissions will be reduced from pre-production and early-production operations since the proposal requires the development of response procedures to elevated emission levels that could result in emission reductions.

ii. To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.

Based on the Division's 2017-2019 inventory data and information from the Colorado Oil and Gas Conservation Commission (COGCC), the Division estimates that an average of 107 pre-production operations per year could be impacted by the proposal.[13] Note, however, that the number of impacted operations may be less in the coming years based on reduced drilling activity for oil and gas resulting from the COVID-19 pandemic and less demand. The Division has not received updated projections from industry on impacted operations.

Since the Division is not specifying a particular air monitoring technology or method that owners or operators must use under the proposed rule, costs of the proposed revisions will vary and may range from hundreds to tens of thousands of dollars per sensor and system. However, low-cost monitoring sensors are typically those considered to be less than $2,500.

In response to industry requests, the Division is providing some additional estimates on upfront sensor costs. Note that these are one-time capital costs, and not the annualized costs generally provided by the Division. Based on the Ramboll report, "Technology Assessment Report: Air Monitoring Technology

[13] See Table 11, Final EIA

near Upstream Oil and Gas Operations",[14] gas monitoring technologies can be grouped into the following broad categories:

- Open Path Optical/Laser Absorption Spectroscopy
- Extractive (nonopen path) Optical/Laser Absorption Spectroscopy
- Chromatography
- Ionization
- Reactive

According to the Ramboll report cited above, depending on the specific type of sensor, open path spectroscopy can be used to continuously measure methane, benzene, and non-methane organic compounds (NMOCs) over long distances, up to hundreds of meters, often with high accuracy for multiple compounds simultaneously. These open path sensors are often used for regulatory fenceline monitoring and may cost $15,000 to over $400,000, depending on the technology and manufacturer. Open path sensors are the only technology discussed here that allows for monitoring large distances with a single sensor; all other technologies would likely require an array of multiple localized sensors. Non-open path spectroscopy can also be used for continuous methane, benzene, and NMOC monitoring, though these sensors do not measure over long distances and generally only measure one compound at a time. Costs for non-open path sensors may range from $1,000 to $150,000. Chromatographs can accurately measure methane, benzene, and NMOCs simultaneously, and though the measurements are near real-time, they are not continuous. Traditional bench top chromatographs utilizing mass spectrometry are relatively large and have higher power consumption. Combined with costs of $20,000 - $60,000 (specialty units for measuring natural gas in pipelines may cost well over $100,000); these traditional chromatographs may be more suited to mobile, vehicle-based monitoring than remote field installations. Newer, portable gas chromatographs are much more suited to rugged environments and may cost $5,000 - $25,000. Photoionization sensors, which may be included in portable chromatographs, can continuously monitor benzene and other air toxics, but are unable to measure methane or take readings. Photoionization sensors are relatively low cost at $1,000 - $10,000. Finally, reactive sensors including electrochemical (EC), metal oxide semiconductor (MOS), and pellistor sensors offer the lowest monitoring cost, with transmitters costing less than $2,000 and replacement sensor heads often costing below less than $500. Unfortunately, reactive sensors typically have low accuracy and may be sensitive to sensor poisoning or changes in temperature, air pressure, and humidity. Despite these issues, a large array of reactive sensors may be sufficient for certain monitoring situations. As discussed above, air monitoring options range from very expensive, accurate monitors that may be hundreds of thousands of dollars to low-cost sensors that may cost less than $2,500, but have limited accuracy.[15]

California's South Coast AQMD Air Quality Sensor Performance Evaluation Center (AQ-SPEC) program provides another valuable source of air monitoring sensors information, including PM sensors, which were not discussed in the Ramboll report. The AQ-SPEC program has compiled a gas-phase sensor evaluation table that summarizes data on twenty-two gas-phase (O3, NO2, CO, SO2) sensors that range from $200 to $10,000 per sensor.[16] AQ-SPEC's PM sensor evaluations summary table lists 50 PM sensors ranging in estimated cost from $100 to $7,000 per sensor.[17] Similarly, Methane Observation Networks with Innovation Technology to Obtain Reductions (MONITOR) projects on Advanced Research Projects Agency-Energy's (ARPA-E) website list monitoring systems with costs ranging from $300 to $3,000 per sensor.[18] In addition, while real-time data air monitoring during oil and gas production has only been occurring in recent years, refineries have been monitoring air quality for several years. EPA revised its National Emission Standard for Hazardous Air Pollutants (NESHAP) from Petroleum Refineries, 40 CFR Part 63 Subpart CC, in 2015 to include a fenceline monitoring work practice standard to improve the management of fugitive emissions. EPA evaluated a fenceline passive diffusive tube monitoring requirement and estimated the annualized costs for three model plants at

[14] EDF/Ramboll. "Technology Assessment Report: Air Monitoring Technology near Upstream Oil and Gas Operations", published December 2017 at https://www.edf.org/sites/default/files/Ramboll-report.pdf
[15] MDPI, "Low-Cost Air Quality Monitoring Tools: From Research to Practice (A Workshop Summary)", published October 2017.
[16] South Coast AQMD, AQ-SPEC Air Quality Sensor Performance Evaluation Center, Summary of Gas Phase Sensors
[17] South Coast AQMD, AQ-SPEC Air Quality Sensor Performance Evaluation Center, PM Sensor Evaluations
[18] ARPA-E, Listing of MONITOR Projects

$41,000 (18 monitoring sites), $47,600 (26 monitoring sites), and $52,500 (32 monitoring sites) per year.[19]

The sensor descriptions and cost data provided above is intended to provide a high-level summary of some of the technologies available in the market, but is not intended as an endorsement of a particular technology, manufacturer, or monitoring method. Although the Division will review and ultimately must approve the monitoring proposals submitted by operators, it fully expects to see a number of different solutions that will be tailored to specific site locations, stages of operation, performance targets, and other specific requirements. The Division believes that this approach will collect a variety of air pollutant emissions data and will further the development of monitoring programs.

Additionally, the Division believes that high-sampling-frequency monitoring may provide earlier notifications of potential leaks, which may reduce product losses and partially offset the upfront and ongoing costs of monitoring.

The Division anticipates working with stakeholders to develop a monitoring plan template, which will reduce cost and staff time in developing these monitoring plans and submitting them to the Division for approval, though the Division has not estimated these potential costs. Since this proposal is for monitoring, it is not expected to lead to immediate emission reductions. However, the information gathered by operators will inform future Division monitoring proposals. Further, the Division expects that if operators observe emissions, the operators will take actions as appropriate to address them, which will have real time reductions not accounted for in the Division's analysis. The Division anticipates that these future proposals will set forth specific monitoring system performance standards and the resulting data will allow industry to more rapidly respond to detected emissions of methane and VOCs, which negatively impact climate and health as GHGs and ozone precursors.

The Divisions anticipates additional sales for manufacturers and installers of monitoring technologies and data systems because the proposed revisions will increase usage of their products and services. The proposal could also lead to a slight increase in employment for monitoring system installers and maintenance employees. However, the Division is unable to quantify the potential sales or employment increases because the monitoring proposal does not require the usage of technologies provided by specific companies.

The Division requested Colorado-specific information on costs and benefits to manufacturers and sellers of monitoring and data storage systems, but did not receive any additional information.

iii. *The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.*

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 and currently anticipated resources.

iv. *A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.*

The responses to subsections i. and ii. above identify the probable costs and benefits of the proposed rule. A primary benefit is being able to gain a better understanding of emissions from oil and gas pre-production and early-production operations and options for monitoring such emissions, which could help inform evaluations of potential health impacts from such operations, opportunities to reduce emissions, and development of more refined monitoring programs. Another benefit of action, though largely unquantifiable, is the impact on communities in which oil and gas drilling operations take place. These

[19] See EPA's Fenceline Monitoring Impact Estimates for Final Rule, EPA-HQ-OAR-2010-0682 (June 4, 2015). For the small model plant, purchased equipment total capital costs were $86,650 ($89,270 for the medium model plant, $90,880 for the large model plant) and included a meteorological station, instillation, ancillary planning/selecting costs, and shipping. Annualized operating costs were $28,680 ($34,910 for the medium model plant, $39,550 for the large model plant) and included equipment maintenance/insurance, sampling collection, sampling analysis, recordkeeping, and reporting.

communities raise concerns and suffer from impacts such as emissions, noise, light, and other consequences of drilling operations. Monitoring of preproduction and early production operations will provide valuable knowledge to these communities.

The benefits of inaction include cost savings for owners and operators of oil and gas pre-production and early-production operations from not having to install and operate air quality monitoring devices or systems. However, such inaction would fail to gather valuable information to further inform the understanding of oil and gas emissions and monitoring programs.

There are potential concerns if the Commission were to take no action on this proposal. This proposal is intended as a first step in addressing SB 19-181 directives to consider a requirement that oil and gas operators install and operate continuous methane emissions monitors. Specifically, the Division will gather information on monitoring technologies and methodologies necessary to establish a more robust monitoring program to evaluate emissions from the oil and gas sector. The Division's proposal is intended as a good-faith effort towards meeting the monitoring consideration requirement under SB 19-181 by allowing for a more comprehensive evaluation of monitoring methods and technologies to be used to refine the monitoring provisions in the future.

v. *A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.*

The Division has not left out less costly or less intrusive methods for achieving the purpose of the proposed rule. The Division has not proposed a specific monitoring technology or method by which operators must meet the requirements of the rule, and leaves it up to operators to design their own monitoring plan or program within certain parameters.

The Division has considered reduced durations of monitoring that would lessen costs, such as only monitoring during pre-production, monitoring during pre-production and just the first ninety (90) days of early-production, or the option to discontinue monitoring after the first 90 days of early-production if no issues or major concerns are identified during that time. However, the Division has concerns with these approaches due to the potential for not gaining a more complete understanding of emissions when they are at their highest potential, which is a primary purpose of the proposed rule. Data on average oil and gas production shows that production does not begin to level off significantly until six months to a year after a well is first producing.[20]

The Division requested that owners or operators of potentially impacted operations and supporting businesses provide Colorado-specific cost information concerning the proposed revisions but did not receive such information that could allow for an evaluation of whether there might be less costly methods for achieving the purpose of the proposed rule. Occidental Petroleum provided one estimate for implementing a monitoring program at an average of $20,000 per month per well pad.[21] However, the Division has not been able to evaluate the accuracy of this estimated cost, which is likely specific to the monitoring technology and program implemented by Occidental.

vi. *A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.*

The Division examined two alternative methods or approaches to its proposal for air quality monitoring during pre-production and early-production operations, as discussed in the Cost Benefit Analysis. The Division also considered alternatives as set forth in the various redline submittals of parties to this rulemaking. The Division did make some changes to its proposal based on those redlines, and determined that other redline suggestions were either unnecessary or inadvisable. The alternatives discussed herein focus on reference-grade monitoring specific to methane, since SB 19-181 mentions continuous methane emissions monitors, and canister fenceline monitoring.

[20] See Energy Information Administration's "Initial production rates in tight oil formations continue to rise" at https://www.eia.gov/todayinenergy/detail.php?id=24932#tab_3

[21] See Oxy-PHS, p. 6.

A methane-specific reference-grade monitoring program requires sensors that deliver higher quality, precision and performance in monitoring and quantification, as well as high-frequency data streams. This type of monitoring program also requires an enclosed and temperature-controlled environment for the sensors for proper operation; periodic calibration of the sensors, also for proper operation and; a meteorological (MET) station with a 3D anemometer to specify on-site measurement of meteorological conditions, which is necessary for estimating emission rates. At a minimum, at least 3 – 4 sensors/monitors per site or facility would be necessary. Alternatively, a mobile monitoring trailer with all the necessary equipment, monitoring systems, and protections for the equipment could be used, which would be easier to relocate, but would still require at least 3 trailers per site for a comprehensive reference-grade "continuous" monitoring program.

Based on the Division's own experience with the development and operation of a reference-grade air monitoring system known as the Colorado Air Monitoring Mobile Lab (CAMML), the Division was able to estimate costs for a methane-specific reference-grade alternative monitoring proposal. The Division estimates a cost of $40,000 – $110,000 per instrument or sensor; $1,000 - $2,000 for an enclosure for each sensor; $800 - $900 per year for sensor calibration per site, and; $2,000 - $10,000 for a MET station. There are also associated power costs for each enclosure or shelter to operate the sensor and maintain a temperature-controlled environment, though those costs have not been estimated here. The potential costs relating to land use siting concerns, such as access to right-of-ways, or of having to relocate the enclosures or shelters during different phases of pre-production, such as inside or outside of sound walls, are also not estimated here. The total system set-up cost ranges from approximately $126,000 - $366,000 per site/facility if 3 sensors or instruments are used and approximately $167,000 - $459,000 per site if 4 sensors or instruments are used. At a minimum, each system could be deployed an average of ten (10) times over a period of five (5) years with an average six-month deployment per site/facility, although it is highly likely the system could be utilized for longer than 5 years. This results in an average cost of approximately $12,600 - $36,600 per site monitored over a 5-year period if 3 sensors or instruments are used and approximately $16,700 - $45,900 per site/facility monitored over a 5-year period if 4 sensors or instruments are used. However, these costs for a single operator would be compounded if the operator was conducting pre-production operations at more than one location at a time. Alternatively, if a mobile monitoring trailer is used with all necessary equipment installed, the estimated total set-up cost is $80,000, so a total of $240,000 per site if 3 trailers are used. With the same deployment schedule noted above, the average cost per site monitored is $24,000 over a 5-year period.

The benefits of pursuing this alternative include obtaining high-quality data on methane emissions from pre-production and early-production operations that could be used to better estimate the rates of GHG emissions from these operations. Understanding methane emissions from pre-production operations has been challenging and this approach would assist in identifying emissions that have previously been difficult to quantify. These precision measurements could also help provide a better idea of the sources of methane associated with this stage of oil and gas development and assist in exploring and evaluating emissions reduction opportunities for such operations. However, this approach would not necessarily inform the emissions of or monitoring technologies for other pollutants of potential concern such as VOCs or hazardous air pollutants.

The second alternative the Division considered would require operators to monitor emissions at the fenceline by capturing a sample using a canister. This would likely reduce the monitoring burden for industry, which could collect a single sample over a longer period. The Division rejected this approach for multiple reasons. First, sample canisters are not collected or analyzed quickly enough to provide timely information to the public or the Division in case of a sudden emissions event. Therefore, this approach would fail to achieve the intent of SB 19-181 for continuous, or near real-time monitoring. Second, this approach also restricts the Division's ability to better understand the amounts and types of air emissions during pre-production and early production. The types of emissions that can be monitored with this approach are based on the sample collection and handling quality and the capabilities of the lab analysis equipment, which are largely static.

The Division's proposal is the better approach for the purpose of the rulemaking rather than the noted alternatives since the proposal will allow for the investigation and evaluation of a range of monitoring technologies, including their costs, capabilities and limitations, which will help inform and focus future proposals for monitoring required under SB 19-181. The Division did not propose the alternatives because they would not achieve the Division's broader goals and would not achieve the intent of SB 19-181.

IV. Reduction of VOC emissions from pre-production tanks and vessels (i.e., flowback vessels) and periodic visual inspections of flowback vessels and associated equipment (Regulation 7, Part D, Section VI.).

i. A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.

The proposal affects the oil and gas industry and supporting businesses in Colorado, specifically those associated with pre-production operations. Flowback service providers and oil and gas companies that drill and produce from new wells will bear the costs of this proposal.

Local governments that receive revenue from oil and gas operations may also be indirectly impacted by the proposed rules, though there is no indication or evidence that this impact is likely to occur as a result of the proposal. Since the Commission adopted significant revisions to Regulation 7, there has been no decrease in drilling activity prior to 2020. In fact, since 2014, drilling activity and associated production has increased significantly in the state. However, this trend may not be reflective of current and future years of drilling and production as oil and gas production in 2020 thus far has been impacted by COVID-19.

The proposed Regulation 7 revisions will benefit companies that manufacture and/or provide enclosed vapor-tight flowback tanks and tank measurements systems, as well as companies that manufacture, distribute and/or service enclosed combustion devices (ECDs), auto-igniters for ECDs, or vapor recovery units (VRUs).

The proposal will significantly benefit drilling/pre-production operations employees who will no longer need to open thief hatches or other access points on flowback vessels to determine the quantity of liquids in the vessels and will, therefore, avoid exposure to potentially hazardous levels of hydrocarbon emissions from the vessels.[22] The proposal will also benefit all individuals present or working at drilling operations during the flowback phase through a reduction in exposure to emissions on-site.

Finally, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of drilling operations by minimizing and reducing exposure to emissions from these operations. The citizens in the DMNFR and ROS will benefit from the proposed rule revisions through reduced VOC emissions, improved ozone levels, reduced GHG emissions and reduced impact of climate-influenced events.

ii. To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.

The Division is proposing emissions control and monitoring requirements for flowback vessels and associated equipment. These requirements include using vapor-tight flowback vessels and conducting periodic visual inspections of the flowback vessels and associated equipment. These requirements would apply to owners of operators of pre-production operations.

Flowback vessels are used during oil and gas pre-production activities and can lead to uncontrolled methane and VOC emissions if the vessels are not designed to contain these vapors. Oil and gas pre-production operations involve well development activities occurring before the date of commencement of operation including drilling, hydraulic fracturing, and flowback. The completion process (i.e., fracking through flowback) prepares the well for continuous production through the flowback of sand and various liquids injected into the well during the hydraulic fracturing process. The liquids and dissolved gases from well flowback operations are sent to a fleet of flowback vessels which are often portable tanks, and may currently be open topped or covered. Open topped flowback tanks do not adequately capture and control those vapors. Therefore, the Division is proposing a new requirement for vapor-tight flowback vessels, which can control these emissions.

[22] See NIOSH-OSHA Hazard Alert: Health and Safety Risks for Workers Involved in Manual Tank Gauging and Sampling at Oil and Gas Extraction Sites at https://www.cdc.gov/niosh/docs/2016-108/pdfs/2016-108.pdf?id=10.26616/NIOSHPUB2016108

The Division has received reports of pre-production activities around the state that suggest that flowback vessels generally do not appear to be vapor-tight. In addition, EPA's NSPS OOOOa does not subject well completion vessels to the storage tank control requirements during the reduced emissions completion (REC) process. The lack of widespread use of vapor-tight flowback vessels is not due to commercial availability or technical constraints; Division research indicates that vapor-tight flowback vessels are manufactured, available, and technically feasible for flowback operations. In addition to the vapor-tight tanks, steel piping is necessary to connect all the active flowback vessels to a common manifold for routing vapors to the enclosed flare and a liquid knockout vessel may be required for safety. This additional equipment is also widely available and technically feasible to install and operate.

The Division's cost estimates assume that most operators will choose to utilize temporary flowback vessels. However, the proposed changes to Regulation Number 7 allow for the usage of permanent production storage tanks for flowback operations, based on stakeholder feedback. The Division requested more information on the feasibility, practicality, and limitations of using permanent production storage tanks for flowback operations. Stakeholders commented that the use of permanent storage tanks may be feasible but not preferable, due to the quantity and quality of the liquids from flowback. If operators use their permanent storage tanks for flowback, operators may save the costs of renting temporary flowback tanks. The stakeholders did not provide estimated costs or savings associated with utilizing permanent storage tanks versus temporary flowback tanks, and the Division has not independently estimated these costs/savings.

Regulation Number 7, Part D, Section II.C.1.c., requires that all owners and operators of storage tanks in the state with uncontrolled VOC emissions greater than or equal to 2 tpy collect and control emissions with air pollution control equipment that achieves 95% control efficiency. Most operators comply with the control requirement by installing an ECD. Most newly completed wells at well production facilities with storage tanks on site would be expected to have uncontrolled VOC emissions well above the 2 tpy threshold. Further, operators are likely to have an ECD onsite during pre-production operations due to the REC requirements in EPA's NSPS OOOOa. Accordingly, the Division is not including the cost of an ECD in the flowback analysis because of the NSPS OOOOa requirements for well completions and Regulation Number 7 requirements for emission controls at the majority of well production facilities with tanks after the well begins production.

Based on stakeholder input, the Division provides example costs of flowback vessels. Flowback vessels, which are often referred to as frac tanks, may be smooth wall, corrugated wall, insulated, round bottom, or V bottom. A typical 500 barrel (BBL) open top frac tank with gas buster is $39,500. A gas buster "is a vessel containing a series of baffles with a liquid exit on the bottom and a gas vent line at the top of the vessel. It rids the vessel of invaded gas or air including CO_2, H_2S, methane and many others found in the oilfield." However, these flowback vessels can be enclosed and include pressure relief valves and level gauging. A typical closed top, 500 BBL vapor-tight frac tank is $30,500. In addition, used tanks range from $19,750 to $7,000. It is important to note that these frac tanks are portable and will be moved from one pre-production facility to the next. Therefore, the complete tank costs cannot be associated with reducing emissions from just one flowback operation and the Division cannot precisely estimate the $/ton of emission reduced from these tanks. In the Cost Benefit Analysis, the Division provides a range of $/ton estimates including a high estimate that assumes all costs are assigned to a single well production facility ($8,069 - $27,551/ton of methane reduced), and a more realistic scenario where the flowback tanks are reused at multiple well production facilities each year ($54 - $184/ton of methane reduced). Flowback service providers would likely absorb some of the costs but would need to distribute the additional costs of providing vapor-tight tanks to operators. Nevertheless, the Division estimates that a typical well production facility with 10 wells can have around 10 to 15 flowback vessels each having a 500 BBL capacity on site during typical well completion activities. The actual number of flowback tanks could vary depending on whether outflow is managed through direct pipe to a centralized facility or the frequency of truck loadouts. The number of wells under active development at the well production facility could also affect the number of flowback vessels needed day-to-day but the Division assumes that the flowback vessels would be periodically pumped to reduce the need to bring in extra tanks. Accordingly, the Division estimates that a fleet of about 12 enclosed vapor-tight flowback vessels would be needed to support a typical well production facility during well completion activities. Enclosed flowback vessels are assumed to have a useful life of about 15 years.

Based on a study involving ten flowback operations in the Rocky Mountain Region, the Division estimates that each flowback operation releases on average about 24.4 thousand cubic feet (MCF) of methane. Flowback activities likely emit other hydrocarbons, including VOCs, although the Division does not have sample data to understand the magnitude of the VOC emissions.

The Division recognizes that estimating the future number of statewide well completions is uncertain because of many factors including the global pandemic and associated fluctuations in commodity prices. Historic oil and gas production data from the COGCC suggests that past economic downturns or price fluctuations cause slight temporary pauses in statewide production but the general trend continues to increase. To further support the demonstration of these trends, the Division analyzed historical data on the annual number of well production facilities permitted by the Division, the number of well completions based on COGCC data, and estimates on average number of well completions per well production facility for different averaging periods along with estimates of average methane emissions. The analysis clearly shows there is a downward trend in the number of well production facilities permitted each year, but the number of well completions remains fairly steady. The shorter 3-year averaging period shows that the number of well completions is higher than the 5-year average but below the 10-year average. Considering the rapid change experienced in the oil and gas sector over the past decade, including the transition from vertical wells to horizontal wells, the Division uses the most recent 3-year average for projecting the future number of well completions statewide (107 per year).
In order to ultimately determine the $/ton cost of the vapor-tight flowback vessel proposal, the Division calculated the tons per year (tpy) methane reductions from the proposal, which range from 7.18 to 2.1 tpy reduced depending on the oil and gas production data averaging period used.[23]

Based on cost data for new enclosed vapor-tight flowback vessels provided by Dragon and assuming a nominal cost for purchase and installation of steel piping for routing vapors to the ECD and annual maintenance, the Division estimates the annualized cost for one enclosed flowback vessel is about $4,830.[24] Using the assumption that a fleet of 12 enclosed vapor tight tanks are needed to support typical well production facility completion activities, the Division estimates the total annualized cost is about $57,958.[25]

The Division estimated annual methane control costs assuming that the fleet of 12 tanks is dedicated to a single well production facility each year. This estimate overstates the costs of the vapor-tight flowback vessel proposal, but is useful to provide a worst-case cost effectiveness estimate. Under the three different oil and gas production data averaging periods, the annual methane control costs range from $8,069 - $27,551 per ton of methane reduced.[26]

The Division also estimated the cost effectiveness assuming that each fleet of flowback vessels will be used at 10 well production facilities each year. The Division believes that this is a much better representation for how the flowback vessels will actually be utilized and results in significantly lower estimates of $54 to $184 per ton of methane reduced, depending on which of the three different O&G production data averaging periods are utilized.[27]

Because of this, the Division estimates that the flowback vessel proposal achieves cost effective benefits of GHG reductions through lower methane emissions. The proposal would be even more cost effective if the Division had estimated the ozone benefits from reduced VOC emissions during flowback.

iii. *The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.*

[23] See Table 13, Cost Benefit Analysis
[24] See Table 14, Cost Benefit Analysis
[25] See Table 15, Cost Benefit Analysis
[26] See Table 16, Cost Benefit Analysis
[27] See Table 17, Cost Benefit Analysis

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 and currently anticipated resources.

iv. A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.

The responses to subsections i. and ii. above identify the probable costs and benefits of the proposed rule. A primary benefit is a reduction in emissions from oil and gas pre-production operations, which provides immediate benefits to those living, working, or recreating at or within the vicinity of such operations. Another benefit of the proposal is that it fits within a strategy to minimize emissions from oil and gas operations, as required by SB 19-181, and helps Colorado in reaching the GHG reduction targets set forth in House Bill 19-1261 (HB 19-1261) by reducing methane.

The probable costs of inaction include those associated with potential impacts to public health and the environment. Inaction could worsen the DMNFR's ozone problem, which has negative health impacts for affected residents in that area. Ground-level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. EPA's ground-level ozone web page notes, "Ozone can worsen bronchitis, emphysema, and asthma, leading to increased medical care."[28] Consequences of a failure to attain the NAAQS in the DMNFR include the imposition of more control measures upon all industries in the DMNFR, including the oil and gas industry.

Inaction could also potentially lead to NAAQS violations in the ROS, which would have significant and negative economic impacts on those areas. Further, inaction will lead to increased methane and ethane releases to atmosphere, and could exacerbate the impact of climate-related events and associated costs.

There could also be inaction costs resulting from health and safety issues from individuals having to manually gauge flowback vessels and potentially exposing themselves to harmful or dangerous levels of emissions.[29]

The benefits of inaction include cost savings for owners and operators of oil and gas pre-production operations and flowback service providers from not having to install and operate enclosed vapor tight flowback vessels and emissions control devices for those vessels at drilling operations.

The costs of inaction outweigh the costs of the Division's proposed rule.

v. A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.

The Division is unaware of a less costly or less intrusive method to achieve the purpose of the proposed rule, which is to reduce emissions from flowback vessels. EPA's NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to utilize enclosed vessels or control emissions from those vessels. The Division could just require the use of enclosed flowback vessels without associated emissions control but emissions would not be reduced significantly with that approach. Furthermore, the bulk of the new costs associated with the Division's proposal result from the requirement to utilize enclosed flowback vessels (see Final EIA and response to subsection ii. above), which the Division estimates to be cost-effective.

[28] See EPA's Gound-level Ozone Basics at https://www.epa.gov/ground-level-ozone-pollution/ground-level-ozone-basics#wwh
[29] See NIOSH-OSHA Hazard Alert: Health and Safety Risks for Workers Involved in Manual Tank Gauging and Sampling at Oil and Gas Extraction Sites at https://www.cdc.gov/niosh/docs/2016-108/pdfs/2016-108.pdf?id=10.26616/NIOSHPUB2016108

Additionally, the Division has not proposed a specific method by which operators must achieve the flowback vessel control requirements. While the Division assumes that operators will likely use enclosed ECDs, the proposal allows operators to use other air pollution control equipment that achieves at least 95% control of emissions. The Division in its analysis has presented controls that are technically feasible and economically reasonable.

The Division requested that owners or operators of potentially impacted operations provide Colorado-specific cost information concerning the proposed revisions but did not receive such information that could allow for an evaluation of whether there might be less costly methods for achieving the purpose of the proposed rule. The Division has updated the cost information for vapor tight flowback vessels through its own research and analysis.

vi. *A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.*

The Division considered requiring a closed-loop system to control emissions during flowback, a process that is currently utilized by some operators in Colorado. This alternative would further reduce methane and other emissions, including NOx and CO2, compared to the ECD controls modeled in the Division's analysis. However, the Division did not have the necessary cost data to perform a thorough analysis of this approach. In addition, the Division notes that its current proposal does not mandate an ECD or any other emission control methodology; operators can select from any emission reduction that achieves at least 95% control efficiency, as required in Regulation Number 7. The Division ultimately rejected this option for the current proposal which provides greater control option flexibility for operators and is cost effective, as indicated by the Division's analysis.

V. Reporting of CO2 and N2O emissions from downhole well maintenance, well liquids unloading events, and well plugging; reporting of CO2 and N2O emissions from the natural gas transmission and storage segment, and; reporting of CO2 and N2O emissions from oil and natural gas operations and equipment (Regulation 7, Part D, Sections II.G, IV., and V.).

i. *A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.*

The proposal broadly affects the oil and gas industry in Colorado, including the upstream and transmission and storage segments, as well as class II disposal well facilities, which will have to report emissions and bear the costs of the proposed rule. Note, however, that these costs will not be entirely new costs since the proposal builds on an existing emissions reporting requirement for oil and gas operations adopted into Regulation 7 in December 2019.

The proposal may benefit any third party contractor selected and funded by the transmission and storage segment to compile and report emissions data to the Division, although this benefit was already accounted for in the Regulatory Analysis for the December 2019 rulemaking.

The proposal could also benefit consultants hired by oil and gas companies to compile and report emissions to the third party contractor or Division on behalf of a company.

The proposal broadly benefits all persons in Colorado by providing a more complete understanding of individual and total greenhouse gas emissions from oil and gas operations in the state, which could inform efforts to reduce such emissions and the impacts of climate-influenced events.

ii. *To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.*

In December 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Regulation 7, Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, carbon monoxide, ethane, and methane emissions to the Division on an annual basis. To further address and inform the GHG directives of SB19-096 and HB19-1261, this proposal expands the Regulation 7 reporting requirements to include the reporting of CO_2 and N_2O, emissions from Colorado's oil and gas sector. Because this proposal builds on existing reporting requirements, the Division believes there will be minimal impacts to the oil and gas industry to comply with the proposed rule. Costs associated with this rule will be absorbed or rolled into existing or planned costs for complying with the current reporting requirements in Regulation 7, which were identified in the Regulatory Analysis for that rulemaking.

iii. *The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.*

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 and currently anticipated resources.

iv. *A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.*

There are potential legal concerns and associated costs if the Commission were to take no action on this proposal since enacted legislation under SB19-096 by the Colorado General Assembly requires monitoring and reporting of GHG emissions to the state by GHG emitting entities, such as oil and gas operations. SB19-096 defines GHG emissions as including CO_2, methane (CH_4), N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6) and nitrogen trifluoride (NF3). In December 2019, the Commission adopted new requirements under Regulation 7 for oil and gas operations to report emissions to the state, which includes reporting of CH_4 emissions. However, other GHG emissions from oil and gas operations, such as CO_2 and N_2O, were not included. Therefore, the Division is proposing to add CO_2 and N_2O to the Regulation 7 emissions reporting requirements for oil and gas to meet the requirements of SB19-096. Failure to adopt this proposal by the Commission would mean failure to meet the statutory directive under SB19-096 to require reporting of all designated GHGs that result from oil and gas operations.

The only benefit of inaction is the cost savings for affected entities under the proposed rule, which will be minimal. The Division has worked with the oil and gas industry to develop the emissions reporting forms that will be used to meet the existing Regulation 7 requirements and has discussed the reporting of additional GHGs with industry. The Division believes that the reporting of CO_2 and N_2O can be incorporated into impacted oil and gas owners and operators reporting program at little to no additional cost.

The Division also notes that the EIA for Regulation Number 22, which was approved by the Commission in May 2020, also argued that the costs of reporting GHG emissions from the oil and gas sector were essentially accounted for in the implementation costs of the 2019 Regulation Number 7 reporting requirements. The Division requested oil and gas industry feedback with specific cost information for GHG reporting, but did not receive any cost estimates during the development of the Final EIA or in prehearing statements.

v. *A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.*

The Division is unaware of a less costly or less intrusive means to achieve the purpose of the proposed rule since there is a statutory directive for the Commission to adopt reporting requirements for the GHGs covered under the proposal. The Division believes that including reporting of CO_2 and N_2O as part of an existing reporting requirement for oil and gas operations is cost-effective.

The Division requested that owners or operators of potentially impacted operations provide Colorado-specific cost information concerning the proposed revisions but did not receive such information that could allow for an evaluation of whether there might be less costly methods for achieving the purpose of the proposed rule.

vi. *A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.*

There is generally consensus around the annual reporting requirements, especially the addition of CO_2 and N_2O reporting. Stakeholders generally agree that the Division's proposal is a reasonable step to implement SB19-181, HB19-1261, and SB19-096. SB19-096 requires GHG emitting entities, including oil and gas operations, to monitor and report GHG emissions to the state. SB19-096 further clarifies that GHG emissions includes emissions of CO_2, CH4, N_2O, HFCs, PFCs, SF6, and NF3. Because the Division's proposal includes reporting of CO_2 and N_2O from oil and gas operations, as directed in approved legislation, the Division believes its proposal is reasonable and necessary.

Some stakeholders suggested that additional time may be provided in order for owners and operators to modify their data systems in order to report CO_2 and N_2O. However, as discussed in the Division's Prehearing and Rebuttal Statements, the Division has worked with the oil and gas industry to develop the reporting forms and best methods for reporting emissions data, which can be utilized to meet the requirements under this proposal. Therefore, the Division does not believe additional time is necessary for owners and operators currently subject to the existing reporting requirements to report CO_2 and N_2O emissions. Therefore, the Division is not analyzing any alternatives for this portion of the proposed annual reporting requirements.

The Division has also proposed additional emission reporting requirements for class II disposal well facilities (see Section VI. below), and will work with stakeholders in developing the annual inventory reporting form to specify the appropriate sampling protocols and emission estimates for various facility designs and throughput. To avoid potential retroactive compliance issues, the Division has clarified in its proposal to exclude the class II-specific data elements from the current 2020 data collection requirements. The clarification notes that owners or operators of class II disposal well facilities will begin collecting data May 1, 2021. Because the Division has addressed compliance data concerns for class II disposal well facilities, and is continuing to work with owners and operators on the reporting form and required data elements, the Division does not have additional alternatives to discuss.

VI. Reporting and reducing emissions from class II disposal well facilities (Regulation 7, Part D, Sections II. And V.)

i. *A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.*

The proposal affects the oil and gas industry and supporting businesses (e.g. hauling companies) in Colorado. Companies that will bear the costs of this rule change include owners and operators of class II disposal well facilities, particularly those with hydrocarbon liquids loadout with uncontrolled actual emissions of 2 tpy or greater on a rolling-12 month basis.

The proposal will benefit those companies that manufacture and/or distribute ECDs, auto-igniters for ECDs, or VRUs, and those that provide vapor collection and return systems. The proposal could also benefit consultants hired by owners or operators of class II disposal well facilities to compile and report emissions to the Division on behalf of an owner/operator.

The proposal will also benefit employees of hauling companies through reduced exposure to hydrocarbon emissions during loadout operations at affected facilities because of emissions control during loadout.

Finally, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of class II disposal well facilities by minimizing and reducing exposure to emissions from these facilities. The citizens in the DMNFR and ROS will benefit from the proposed rule revisions through reduced VOC emissions, improved ozone levels, reduced GHG emissions and reduced impact of climate-influenced events.

ii. *To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.*

<u>Storage Tank Controls</u>

The Division is proposing to clarify that storage tanks at class II disposal well facilities are subject to the storage tank control requirements in Part D, Sections II.B and II.C.; to expand the hydrocarbon liquids loadout requirements in Part D, Section II.5. to hydrocarbon liquids loadout from tanks at class II disposal well facilities; and to clarify and expand the annual emissions reporting requirements in Part D, Section V. for class II disposal well facilities.

The Division has analyzed the costs and emission reductions associated with controlling emissions from storage tanks many times since 2004. Most recently, the Division analyzed the costs and emission reductions associated with lowering the statewide storage tank (i.e., hydrocarbon liquids and produced water) control threshold from 6 tpy to 2 tpy in 2019.[30] The Division's analyses looked at all storage tanks in the Division's inventory with uncontrolled VOC emissions equal to or greater than 2 tpy. As further discussed in the Division's Rebuttal Statement, this analysis included storage tanks at class II disposal well facilities. However, given the pushback from some subject facilities as to the question of whether tanks must install controls, the Division is now clarifying that the statewide storage tank control requirements in Part D, Section II. apply to storage tanks at class II disposal well facilities.

In addition to disputing whether previously approved tank control provision applied to class II disposal facilities, parties also state that it is technically infeasible to control emissions from class II disposal well facility storage tanks.[31] This argument is premised on the "high water vapor, low VOC content, and low pressure at these facilities" resulting in a low BTU content gas stream.[32] In 2019, the Commission afforded operators an off-ramp from the storage tank control requirements in Part D, Section II if the operator could demonstrate that it would need to use supplemental fuel to operate the control device. This existing off-ramp addresses the infeasibility concerns raised by parties. This demonstration remains available to class II disposal well facilities.

The JIWG also takes issue with the Division's EIA concerning class II disposal well facility storage tank controls, providing its own analysis in the JIWG Exhibit 005. As an initial matter, the Division evaluated the costs and benefits of storage tank control requirements in 2014 and again in 2019. This Regulatory Analysis need not address the issue, and any objection by stakeholders to the older analyses is untimely and unavailing. However, the Division has nonetheless reviewed the JWIG cost analysis and, while the Division appreciates the JIWG's data sharing, the Division finds some cost components appear to be overestimated.

For example, class II disposal well facilities handle produced water with low VOC concentrations; thus a smaller emissions control device (ECD) might be used for controlling these vapors. The capital cost of a 30" low pressure ECD could be $8,000 less than a 48" ECD.

Second, the Division understands from stakeholder comments that class II disposal well facilities triggering the storage tank control requirements are always staffed and the flare maintenance cost is

[30] See 2019 final Economic Impact Analysis.
[31] See, for example, JIWG_PHS, pp. 16-18.
[32] Id. at pg. 18.

associated with the staff time involved in checking and managing the fluid level in the drip pot. Therefore, attributing staff time costs to flare maintenance, the JIWG's estimated costs of $30,128 per year, is excessive given automated methods for frequent draining the drip pot are available and feasible. The Division recognizes that some nominal maintenance of the flare is necessary, and costs for maintenance have been included in past rulemakings at levels around $2,500.

Third, the Division understands from stakeholder comments that the $10,000 power extension cost is associated with providing direct power to the auto-igniter. However, recognizing that these facilities are staffed but apparently do not have power at the ECD, this cost seems to be very expensive compared to using a more economic option involving solar power and batteries, which is likely one tenth of the cost. The JIWG's analysis fails to recognize these practical considerations.

Fourth, based on 2019 operator reported APEN data for class II disposal well facilities, the average number of produced water tanks on site is about four tanks with an average storage capacity of about 3,000 barrels. Consequently, the number of fiberglass produced water tanks that require upgrade to steel tanks, twenty tanks per facility in the JIWG analysis, is greatly exaggerated. Moreover, the existing fiberglass tanks will likely have some salvage value or be relocated to other sites, which is ignored in the estimated tank upgrade costs. The Division also questions whether it is appropriate to consider the full tank replacement cost at facilities with anticipated emissions near or above the control threshold when operators elect to use non-pressure rated tanks for economic reasons. Nevertheless, if an average of four 750 BBL tanks per facility are assumed and a salvage value of $1,000 per fiberglass tank is considered, the Division estimates the rescaled capital cost for four tanks at about $98,168, in contrast to the JIWG's estimate of $510,840. If the above suggested corrections are applied to the JIWG cost analysis, the annualized control cost is estimated at about $35,982.[33]

The Division recalculated the JIWG's Exhibit 005 summary table using this more accurate control cost. The emission reductions are based on uncontrolled emissions halfway between the upper and lower bounds (2.5, 3.5, 4.5, or 5.5 tpy) and 95% control efficiency, as required for ECDs in Regulation Number 7. The Division estimates annualized costs ranging from $8,417 to $15,150 per ton of VOC controlled, depending on current uncontrolled emissions from the storage tanks.[34]

These figures assume that four tanks will need to be replaced for every control device installed. If, instead, only one tank needs to be replaced per installed controlled device, the capital cost would be approximately $25,000 and the total annualized costs would be much closer to the typical tank control cost where replacement of the tank itself is not needed. Finally, while the JIWG states that these facilities may utilize fiberglass tanks that would need to be replaced, in the Division's experience these fiberglass tanks are used for produced water and are not typically employed for oil storage. The Division's inventory records indicate that many of the tanks at these facilities with emissions over the control threshold are oil tanks where oil that is separated from the water is stored. In these instances, operators should not incur the additional cost of replacing the tanks.

In light of these reasonable adjustments, the Division believes that controlling tanks at class II disposal well facilities, while somewhat more expensive than at well production facilities, remains cost effective. Nevertheless, the Division will continue to engage with stakeholders to help ensure that controls employed at these facilities are cost-effective.

<u>Truck Loadout of Hydrocarbon Liquids</u>

In 2019, the Division analyzed the costs and emission reductions associated with controlling emissions from the loadout of hydrocarbon liquids to transport vehicles at well production facilities, compressor stations, and processing plants.[35] Because the Division's proposal did not require owners or operators to use a specific control device, cost estimates varied based on the facility configuration and control system installed and ranged from $6,269 to $19,794 per ton of VOC reduced.

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[33] See Table 18, Cost Benefit Analysis

[34] See Table 19, Cost Benefit Analysis

[35] See 2019 final Economic Impact Analysis.

The Division has used a similar analysis to estimate the cost/ton reduced to control loadout emissions of hydrocarbon liquids at class II disposal well facilities. Based on APEN and permitting data, the Division estimates there are 33 facilities that may loadout hydrocarbon liquids from storage tanks.

Generally, many class II disposal well facilities are permitted with a default emission factors that can be adjusted later based on collecting site-specific data. Therefore, it is difficult to draw a general correlation between the oil loadout volume and the facility loadout uncontrolled VOC emissions. Because the Division is proposing a higher applicability threshold of 2 tpy from loadout versus the current 5,000 barrel threshold, it is appropriate to require owners or operators to control emission from the loadout of hydrocarbon liquids from all storage tanks, not just controlled storage tanks. The Division is proposing a loadout threshold for applicability in contrast to the throughput threshold as class II disposal well facilities may not be as likely to already have a combustion device installed and available at the facility, therefore the higher threshold results in a cost per ton analysis that reflects the potential higher costs related to a dedicated flare in relation to the higher emissions associated with the loadout threshold that will be reduced. These costs are discussed in greater detail in the Division's Final EIA.

Operators of class II disposal well facilities have suggested that for sites without an ECD, the most important consideration is the whether the facility has well gas to supply the flare combustion device. Based on stakeholder input for class II disposal well facilities without a supply of well gas, the Division has provided a revised cost analysis for total cost of installing an ECD including the firing of the pilot light with propane. The revised total cost estimate is $17,537.3.[36] The estimated costs for class II disposal well facilities range from $1,244 to $4,563 per ton of VOC reduced, for facilities with access to onsite pilot fuel gas.[37]

Utilizing the annualized flare control costs from Table 20 in the Cost Benefit Analysis, the Division estimated the $/ton cost for controlling emissions from hydrocarbon liquids loadout utilizing an ECD. The emission reductions are based on uncontrolled emissions halfway between the upper and lower bounds (2.5, 3.5, 4.5, or 5.5 tpy) and 95% control efficiency, as required for ECDs in Regulation Number 7. The annualized cost of controlling loadout emissions by installing an ECD with a pilot light fueled by propane for various uncontrolled tanks ranges from $3,356 to $12,306.9 per ton of VOC reduced.[38] These VOC reduction estimates do not include the emissions associated with opening of the thief hatch for purposes of loadout (and associated sampling, if required), and are therefore underestimated, depending on the frequency of loadout.

Further, because the Division's cost analysis reflects the installation of a dedicated flare, the argument that the loadout requirements should only apply to loadout from *controlled* storage tanks[39] does not hold the same weight as when the Commission adopted loadout requirements for well production facilities and natural gas compressor stations using a throughput from control storage tanks threshold. In 2019, the Commission considered a range of control costs due to three primary options available to owners or operators to control loadout emissions: the addition of a vapor line to existing infrastructure; the addition of a vapor line and vapor control system upgrades; and the addition of a dedicated loadout control system. As discussed in 2019, the Division estimated uncontrolled loadout emissions at 5,000 BBLS a year at 0.59 tons per year (tpy). The most cost effective, but unspecified option, was to route the loadout emissions back to the storage tank. If the storage tank was uncontrolled, those emissions could just vent to atmosphere. In this proposal, the Division determined that adding a flare to control loadout emissions is cost-effective, given that controls will only be required if load-out emissions are 2 tpy or greater. Therefore, while owners or operators could still route loadout emissions to a controlled storage tank, the Division anticipates that class II disposal well facilities may have to install a flare, which, again, the Division has estimated to be a cost-effective control strategy. Therefore, it is unnecessary to limit the control of loadout emissions to controlled storage tanks.

<u>Reporting</u>

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[36] See Table 20, Cost Benefit Analysis
[37] See Cost Benefit Analysis, p.31
[38] See Table 21, Cost Benefit Analysis
[39] See Caerus_PHS, p. 3, JIWG_PHS, p. 22, Weld_PHS, pp. 4-5.

The Division is proposing additional annual emissions reporting requirements in Regulation Number 7 for class II disposal well facilities. This information will help inform the Division's emissions inventories and potential future proposals aimed at achieving targeted emissions reductions from these facilities.

The Division recognizes that the proposed reporting requirements will impose some reporting and recordkeeping costs on owners or operators of class II disposal well facilities. However, these reports may partially reduce future reporting burden in other areas including emission inventory development for ozone and other modeling efforts, and measuring progress in GHG emissions reductions associated with SB19-096 and HB19-1261. In some cases, these reports may include information that is already provided by owners and operators for air pollutant emissions notice (APEN) requirements. The Division will continue to identify ways to streamline the reporting requirements in future rulemakings. The Division did not estimate these costs in the Final EIA. It requested additional cost information from industry, but did not receive feedback until after the Final EIA submission, as discussed below.

In its rebuttal statement, the JIWG suggested that the reporting requirements for class II disposal well facilities proposed by the Division will require significant industry investment without any clear emission reduction benefits. As noted in the Cost Benefit Analysis, these reporting requirements are not intended to directly reduce emissions. Further, not every regulation must result in direct emissions benefits to be approvable under the Colorado Air Pollution Prevention and Control Act and the Administrative Procedure Act. Like the proposed monitoring plan requirements, the class II disposal well facility emission information submitted by operators will inform future emissions inventory and reduction strategies.

Additionally, JWIG's rebuttal expressed concerns about the time needed for operators to implement data systems for this emission information. Specifically, the comments stated that operators of class II disposal well facilities that are not currently controlling vapor emissions may require additional time to work with the Division on developing appropriate emissions factors, emissions inventory spreadsheets, and other documentation appropriate to class II disposal well facilities. JWIG also claimed that owners and operators need additional time to develop the database and recording systems. The Division has revised its proposal to provide additional time for the Division to work with operators to develop the reporting forms.

iii. *The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.*

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 and currently anticipated resources.

iv. *A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.*

The responses to subsections i. and ii. above identify the probable costs and benefits of the proposed rule. A primary benefit is a reduction in emissions from class II disposal well facilities, which provides immediate benefits to those living, working, or recreating at or within the vicinity of such operations.

The probable costs of inaction include those associated with potential impacts to public health and the environment. Inaction could contribute to worsening the DMNFR's ozone problem, which has negative health impacts for affected residents in that area. Ground level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. EPA's ground-level ozone web page notes, "Ozone can worsen bronchitis, emphysema, and asthma, leading to increased medical care."[40]

Inaction could also potentially lead to NAAQS violations in the ROS, which would have significant and negative economic impacts on those areas. Further, inaction could also contribute to

[40] See EPA's Gound-level Ozone Basics at https://www.epa.gov/ground-level-ozone-pollution/ground-level-ozone-basics#wwh

increases in methane in the atmosphere, which could exacerbate the impact of climate-related events and associated costs.

The benefits of inaction include cost savings for owners and operators of class II disposal well facilities from not having to install and operate emissions control devices and vapor collection and return systems for loadout at these operations.

The costs of inaction outweigh the costs of the Division's proposed rule.

v. *A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.*

The Division believes it has not left out less costly or less intrusive methods for achieving the purpose of the proposed rule regarding the proposed control requirements for class II disposal well facilities. The purpose of the proposed rule is to clarify the applicability of existing storage tank control requirements and expand hydrocarbon liquids loadout control requirements to reduce emissions from class II disposal well facilities.

Additionally, the Division has not proposed a specific method by which owners or operators of class II disposal well facilities must achieve the control requirements. While the Division assumes that operators will likely use enclosed ECDs, the proposal allows operators to use air pollution control equipment that achieves at least 95% control of emissions. The Division has presented controls that are cost-effective in its analysis for this proposal.

For the proposed reporting requirement, the Division has considered removing the requirement to perform periodic sampling of liquids accepted for injection at class II disposal well facilities, which would reduce costs. However, liquids sampling allows for obtaining the most accurate representation of emissions from operations at these facilities and the purpose of the proposed rule is to gain a better understanding of actual emissions from such facilities and help inform future emission reduction initiatives.

vi. *A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.*

The Division considered a lease automated custody transfer (LACT) unit for hydrocarbon liquid loadout at class II disposal well facilities. A LACT unit provides automatic measurement, sampling, and transfer of liquids, which reduces VOC emissions from the tank and reduces emissions from flare combustion. The Division has not estimated the emission reductions from reduced flaring and the following cost analysis is based solely on the VOC emission reductions. The following costs are based on the Final EIA submitted November 5, 2019, for the December 2019 Regulation Number 7 rulemaking hearing.[41] Depending on the LACT unit design including pipe size, flow meter type, flow conditioning, additional instrumentation and automation, and meter proving capability, the cost of a LACT unit can vary widely. The Division considers the $350,000 estimate listed in Table 22 of the Cost Benefit Analysis to be an average cost, though some LACT units may cost more, which would lead to a higher $/ton cost to control VOC emissions. The Division assumed that the engineering, freight, and installation costs for a LACT unit are similar to these same costs for a flare. This assumption may underestimate the cost to transport and install a large LACT unit skid. The Division estimates the annualized cost of a LACT unit is approximately $58,608.[42]

Utilizing the annualized flare control costs from Table 22 in the Cost Benefit Analysis, the Division estimated the $/ton cost for controlling emissions from hydrocarbon liquids loadout utilizing a LACT unit. For the sake of comparison, the emission reductions are assumed to be the same as the ECD analyzed in Table 22. However, a LACT unit may achieve slightly greater emission reductions by reducing the need to open a thief hatch and by eliminating flaring emissions. The Division estimated

[41] See 2019 Final Economic Impact Analysis.
[42] See Table 22, Cost Benefit Analysis

much higher annualized cost for a LACT unit, ranging from $11,206 to $40,985 per ton of VOC reduced.[43] The Division's proposal allows operators to utilize a LACT unit for hydrocarbon liquid loadout, but the Division did not propose mandatory LACT units based on this $/ton estimate.

The Division has been unable to identify an alternative method that would achieve the purpose of the proposed reporting requirement for class II disposal well facilities since there is a statutory requirement for the direct reporting of GHGs, including CO_2 and N_2O, to the state. Some stakeholders suggested that additional time may be provided in order for owners and operators to modify their data systems in order to begin reporting their emissions annually. The Division agrees that some additional time may be necessary and has revised the proposed inventory rule accordingly.

[43] See Table 23, Cost Benefit Analysis