MEMORANDUM OF NOTICE

Item Title: Regulation Numbers 7 and 22

Meeting Date: September 17, 2021

GENERAL DESCRIPTION

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission (OGCC) and this Commission. In the same session, the General Assembly adopted House Bill 19-1261 (HB 19-1261), setting statewide greenhouse gas (GHG) reduction goals. The General Assembly declared in HB 19-1261 that "climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "many of these impacts disproportionately affect" certain disadvantaged communities. The goals set in HB 19-1261 seek a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels. The GHG Pollution Reduction Roadmap (GHG Roadmap) developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the baselines from which these reduction percentages are to be estimated.

In October 2020, this Commission established a target for the sector including oil and gas fugitive emissions (O&G Sector) of a 36% reduction from the 2005 baseline by 2025 and a 60% reduction from the 2005 baseline by 2030 (from an estimated 20.17 million metric tons (MMT) CO2e to 13 MMT CO2e by 2025 and 8 MMT CO2e by 2030). Commission targets for the sector including residential, commercial, and industrial combustion emissions (RCI Sector) include a 20% reduction from 2005 numbers by 2030. House Bill 21-1266 (HB 21-1266), signed into law on July 2, 2021, memorializes these percentage reductions in statute, and provides additional requirements for the rulemakings to achieve these goals.

In this rulemaking action, the Division is proposing requirements for upstream and midstream segment operations to reduce GHG emissions sufficient - when taken in combination with other regulatory and voluntary actions at operations across the state - to achieve the GHG reduction requirements of HB 21-1266. In this action, the Division is not proposing additional regulations applicable to the transmission and storage segment or the distribution segment.

The proposed revisions to Regulation Numbers 7 and 22 are state-only rules. The Division is proposing additional renumbering, typographical, grammatical, and formatting corrections throughout Regulation Numbers 7 and 22.

The Division is requesting the Commission schedule a three-day public hearing for December 2021 to consider new requirements in Regulation Numbers 7 and 22.

WHAT IS IN THIS PACKAGE?
Attachments to this Memorandum provide details on the proposal as follows:

- Good Cause Letter
- Agenda Item Control Sheet
- Proposed Regulatory Language – Regulation Number 7
- Proposed Regulatory Language – Regulation Number 22
- Statement of Basis, Specific Statutory Authority and Purpose – Regulation Number 7
- Statement of Basis, Specific Statutory Authority and Purpose – Regulation Number 22
- Initial Economic Impact Analysis - Regulations Number 7 and 22

EXPLANATION OF THE PROPOSED RULES

The oil and gas industry is a large source of greenhouse gas emissions, and the largest anthropogenic source of methane in Colorado. Section 25-7-109(10)(a), C.R.S, directs the Commission to adopt rules to minimize emissions from natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain. This proposed program targets the 2025 and 2030 goals, resulting in a 36% and 60% reduction of O&G Sector emissions from a 2005 baseline, respectively. This proposed program also targets the 2030 goal for oil and gas industry emissions from the RCI Sector, resulting in a 20% reduction in the 2015 baseline emissions. Achieving the state's 2050 goals will require more structural adjustments to how CDPHE and other agencies address the various emission source categories.

In October 2020, the Commission refined the state's goals for certain sectors, establishing reduction goals for the oil and gas industry, embedded into statute in HB 21-1266. The GHG Roadmap developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the 2005 baseline from which these reduction percentages are to be estimated, as set forth in the graphic below.

For the oil and gas industry, not all of its emissions are found in the "O&G Sector," also referred to as the "Oil & Gas Fugitive Emissions" category of the GHG Roadmap. Methane emissions from upstream and midstream activities, along with estimates of methane "leakage" from pipelines in the

transmission & storage and distribution segments, are in the O&G Sector. In contrast, most of the emissions from fuel combustion at oil and gas sources in the upstream and midstream segments are actually found in the "RCI Sector" of the GHG Roadmap (specifically in the "industrial" category, which is the subject of new HB 21-1266). As between the O&G Sector and the RCI Sector, based on data estimated for 2005, approximately 87.8% of CO2e emissions from the oil and gas industry were in the O&G Sector; however, based upon 2015 estimates, 73.9% of CO2e emissions from the oil and gas industry are in the O&G Sector. These percentages do not account for the small portion of combustion emissions associated with inter- and intra-state pipelines found in the "Transportation Sector" of the GHG Roadmap and are not specifically addressed by HB 21-1266's revision to § 25-7-105(1)(e), C.R.S. This rule package addresses the emissions associated with the oil and gas industry in both the O&G and RCI Sectors in the GHG Roadmap, but not the Transportation Sector.

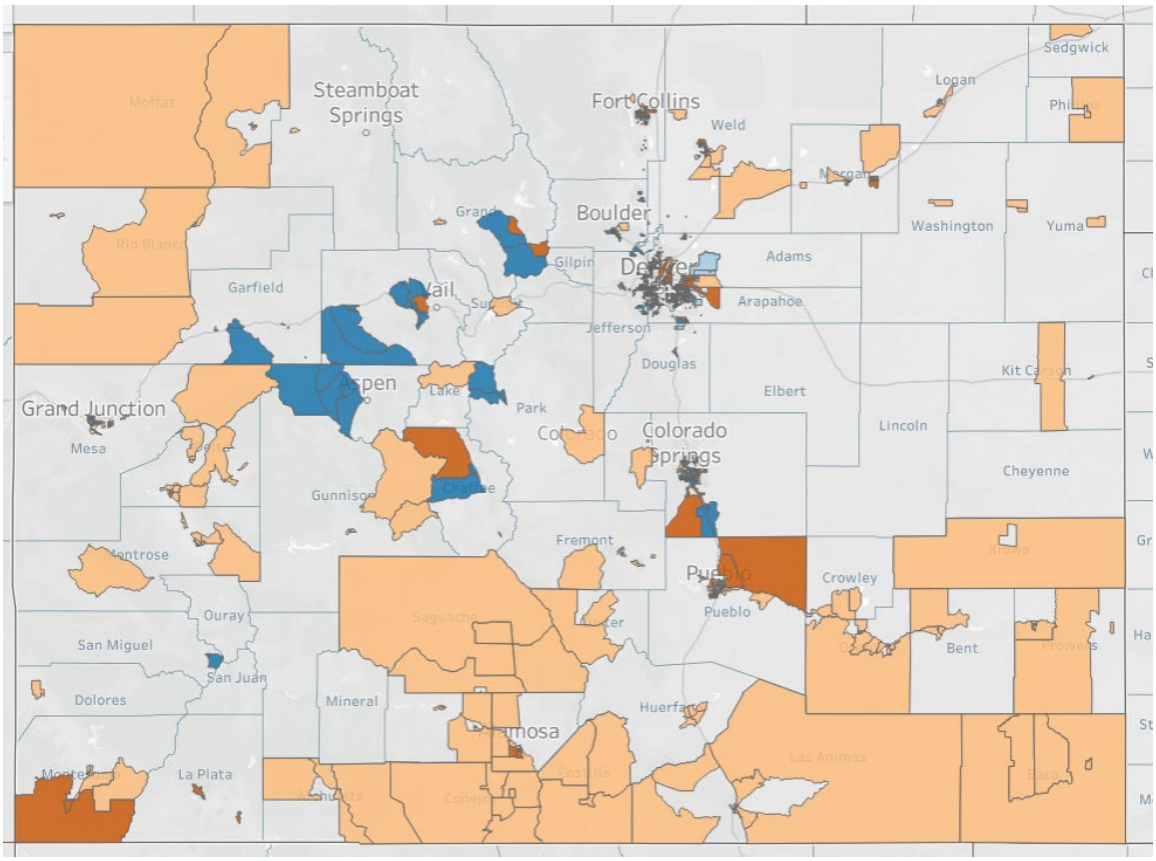
EPA considers the oil and gas industry to break down into four "segments" - upstream, midstream, transmission & storage, and distribution. Upstream is also called exploration and production, while midstream is also called gathering, boosting, and processing. For purposes of this analysis, the Division considers transmission & storage and distribution to be "downstream." Most of the oil and gas stationary source rules in Colorado apply to facilities in the upstream and midstream segments, as they have the largest opportunity for emissions. The Division conducted an analysis of what portion of the 2005 baseline - for the O&G Sector - and the 2015 baseline - for the RCI Sector - could be attributed to upstream, midstream, or downstream. The emissions and percentage contributions to the O&G Sector and RCI Sector are as set forth below:

	RCI Sector 2015 Baseline Emissions (mtCO2e)	RCI Sector %	O&G Sector 2005 Baseline Emissions (mtCO2e)	O&G Sector %	Total O&G and RCI Sector %
Upstream	2,690,692	38.60%	15,184,909	75.30%	65.87%
Midstream	4,279,308	61.40%	2,679,030	13.28%	25.64%
Downstream			2,302,468	11.42%	8.48%

The Division is not proposing regulations applicable to the downstream segment (the transmission and storage segment and the distribution segment). With regard to the transmission and storage segment, the Commission adopted a performance-based program for this segment in 2019 designed to materially reduce greenhouse gas emissions from transmission and storage operations; reporting of progress has not yet begun under that program and the Division believes it reasonable to evaluate the progress of that program before modifying it. The Division is not proposing regulations applicable to the distribution segment because legislation passed in the 2021 session invests the Colorado Public Utility Commission (PUC) with authority over this segment of the O&G industry. The emissions from distribution that are included in the GHG Roadmap for the oil and gas sector are "leaks" from distribution pipelines. Senate Bill (SB) 21-264 requires that gas distribution utilities will submit a comprehensive clean heat plan that demonstrates projected reductions in methane and carbon dioxide emissions that meet prescribed reduction targets. Each clean heat plan must outline the utility's proposal to reduce carbon dioxide and methane emission levels by 4% in 2025 and 22% in 2030. Gas distribution utilities, depending on their size, must submit clean heat plans to the PUC by August 1, 2023, and January 1, 2024. Thus, the Division believes that the transmission and storage performance program, together with the clean heat plans, are likely to achieve reductions of emissions necessary from these segments of the O&G Sector to achieve the goals of § 25-7-105(1)(e)(XII), C.R.S.

The Division has proposed a number of requirements for sources in disproportionately impacted communities. HB 21-1266 defines disproportionately impacted community, but does not specifically identify those communities considered disproportionately impacted. CDPHE is developing a tool to track disproportionately impacted communities, but this tool will not be fully realized in 2021. For

purposes of the Division's proposal, the Division is asking that the requirements for DI communities apply in those communities identified at the time of the December hearing. As of today's date, the DI communities identified are as set forth on the map below:



According to this map, the percentage of Colorado's population that resides in a DI community is as follows:

	Total Population	Population in DI Communities	% of Population in DI Communities
Statewide	5,610,349	1,665,486	29.69%
NAA	3,805,610	1,007,562	26.48%
ROS	1,804,739	595,182	32.98%

The Division expects a version of this map to be publicly available soon, and anticipates specifying in which communities the requirements of the Division's proposal will apply.

<u>Air Pollution Control Equipment (Reg. 7, Part D, Sec. II.B, II.F):</u>

In addition to the GHG program discussed in more detail below, the Division is proposing additional requirements to ensure better performance of air pollution control equipment in both the upstream and midstream segments. The Division's proposal would: expand inspection requirements; mandate the use of flow meters to ensure better monitoring and verification of emissions data; and require performance testing of enclosed combustion devices, prioritizing those devices in disproportionately impacted communities for earlier testing. This proposal is consistent with the directives of HB 21-1266 which require the Commission to adopt direct emission control regulations and ensure reductions of co-pollutants in disproportionately impacted communities. Regulation Number 7 has a number of maintenance and inspection requirements for air pollution control equipment to ensure that control

efficiency is accurate throughout the life of the use of that equipment. However, existing provisions do not uniformly apply to all air pollution control equipment, nor is there currently any performance testing required by regulation (though some performance testing is required by permit). The new requirements would ensure more even application of maintenance and inspection requirements, and would include a performance testing component on a periodic basis to ensure that emission reductions continue to be achieved by these combustion devices over the life of that device. The revisions to Section II.F ensure that devices controlling separation equipment are subject to this program.

Enclosed combustion devices will be subject to ongoing, periodic performance test requirements. This rule creates a performance test approach that will allow the Division to manage testing required by the rule that is different than the current standard stack test oversight model. The Division is not proposing a specific test method that must be utilized, but is proposing that performance testing be conducted pursuant to a Division-approved protocol. The Division's proposal includes more frequent testing for enclosed combustion devices that were not tested by the manufacturer in accordance with New Source Performance Standard (NSPS) OOOOa. The performance testing schedule has a focus on combustion devices in disproportionately impacted communities and in the 8-hour Ozone Control Area to ensure their efficacy in limiting and eliminating GHGs, hazardous air pollutants, and volatile organic compounds (VOCs).

<u>Midstream Segment (Reg. 7, Part D, Sec. II.B.3, II.C.2, II.C.3, II.E, II.H, II.I, Sec. III.C, III.D, III.F; Reg. 22, Part B, Sec. III):</u>

The Division's proposal addresses operations in the midstream segment of the oil and gas industry - made up of the natural gas gathering and boosting segment and natural gas processing segment - which includes natural gas compressor stations, natural gas processing plants, and associated equipment and pipeline systems. The Division's proposal includes the following components:

- Increased LDAR for compressor stations and gas plants;
- Rod packing and pneumatic controller requirements for gas plants;
- Capture/control requirements for pigging and blowdown operations; and
- Long-term planning for midstream fuel combustion equipment.

The Division is proposing new LDAR requirements. First, the Division is proposing to require quarterly – instead of semi-annual – inspections at compressor stations in disproportionately impacted communities. Second, the Division is proposing that all gas plants statewide have an LDAR program that, at a minimum, meets the standards of NSPS OOOO or OOOOa; currently, only gas plants in the 8-hour Ozone Control Area must have an LDAR program that meets the requirements of NSPS OOOO or OOOOa (unless otherwise subject to those federal requirements).

The Division is also proposing to expand requirements for pneumatic controllers at gas plants statewide. Currently, Regulation Number 7 requires that gas plants in the 8-hour Ozone Control Area have zero-emitting pneumatics; the Division's proposal would expand this requirement statewide. The Division's proposal also brings any remaining gas-driven pneumatic controllers at gas plants into the pneumatic controller find and fix program in Regulation Number 7, Part D, Section III.

In Regulation Number 7, Part D, Section II.H, the Division is proposing capture and control requirements for pigging and blowdown operations. Based upon the limited set of data reported to the Division in June 2021 (for the second half of 2020), venting and blowdowns make up the largest set of methane emissions from the midstream segment (after combustion equipment, which is addressed in the fuel combustion equipment proposal below). The Division's proposal includes a requirement to reduce emissions from pigging operations through gas recovery, and for operators to employ best management practices to reduce emissions from pigging operations statewide. The Division's proposal sets an applicability threshold, above which the capture/control requirements would apply - where the midstream operator conducts more than one pigging operation per month (12 times per year). The Division does anticipate the potential for revisions to its proposed applicability threshold, as

appropriate. The Division's proposal also would require that blowdowns from equipment at compressor stations and gas plants be reduced through capture or control. Operators must also employ best management practices to reduce blowdowns of midstream pipelines. The Division has also proposed meaningful recordkeeping provisions to ensure better tracking of these emissions and reduction measures. Reporting has been incorporated into the annual emission reports in Regulation Number 7, Part D, Section V.

Midstream fuel combustion equipment – engines, heaters, boilers, turbines – together are the largest source of greenhouse gas emissions from midstream operations, according to data reported both to the EPA and to the Division. Unlike the emissions from activities discussed above, fuel combustion emissions are in the "RCI Sector" of the GHG Roadmap, and must meet the 20% reduction target (from the 2015 baseline) by 2030. In Regulation Number 22, Part B, Section III, the Division is proposing to establish a steering committee to develop guidance and a segment-wide emission reduction plan, which would be submitted as a regulatory proposal to the Commission for adoption in 2024.

Upstream Segment (Reg. 7, Part D, Sec. II.E, II.G, Sec. VI.C; Reg. 22, Part B, Sec. IV):

The Division is proposing to establish a GHG intensity program for upstream oil and gas operations and equipment in the RCI Sector and the O&G Sector. Intensity represents a ratio of how much greenhouse gas is emitted per unit of production (oil and gas produced). In order to ensure Colorado makes progress towards reduction of GHG on a mass basis, the Division is proposing to have stricter standards for larger operators, to have a strict "new facility" intensity target directed at newly constructed well production facilities, and to augment the intensity program with additional requirements consistent with the requirements of HB 21-1266. The Division refers to its proposal as "Intensity Plus." The Division's "Intensity Plus" proposal for upstream oil and gas operations has three primary components:

- Increased LDAR for facilities in disproportionately impacted communities and for newly constructed facilities;
- Emission reduction requirements for well maintenance operations, including well liquids unloading; and
- Greenhouse gas intensity.

In Regulation Number 7, Part D, Section II.E, the Division is proposing that well production facilities in disproportionately impacted communities should be inspected for leaks on the same schedule as well production facilities within 1,000 feet of an occupied area. The Division is also proposing that newly constructed well production facilities will have a monthly AIMM frequency. Currently, the inspection frequency for well production facilities is set based upon the facility's VOC emissions (from storage tanks). Under this proposal, a newly constructed facility will always be inspected monthly, unless a different program is approved as alternative AIMM or other advanced technologies are employed. Section 25-7-109(10)(b)(I)(C), C.R.S., directs the Commission to consider a requirement that "oil and natural gas operators must install and operate continuous methane emissions monitors at facilities with large emissions potential, at multi-well facilities, and at facilities in close proximity to occupied dwellings." The Commission adopted preproduction and early production monitoring requirements in 2020. This proposal builds off that program by recognizing that operators may, instead of the new monthly AIMM inspections, continue their early production monitoring programs.

The Division is also proposing requirements to address emissions from well maintenance activities covered by Regulation Number 7, Part D, Section II.G. The Division's proposal expands on the current requirement to employ best management practices (BMPs) by identifying some of those required BMPs. The Division's proposal would also require the use of plunger lift or other artificial lift, or air pollution control equipment to minimize emissions specifically from well unloading activities.

In Regulation Number 22, Part B, Section IV, the Division is asking the Commission to set targets for greenhouse gas intensity that step-down over time to achieve the GHG reductions applicable to the O&G Sector and RCI Sector of the GHG Roadmap by 2030. There is currently no regulatory methane

intensity program in the United States. However, there are a number of voluntary programs, including ONE Future, the Natural Gas Sustainability Initiative, etc. Multiple Colorado operators are already participating in voluntary methane intensity programs.

The GHG intensity targets in the Division's proposal were developed based on achieving reductions in the O&G Sector of 36% by 2025 and 60% by 2030 from the final 2005 baseline established by the Division's climate change unit, and reductions in the RCI Sector of 20% from the 2015 baseline. The O&G Sector numbers are based off of the 2005 baseline as set forth in the October 2020 Commission resolution of 20.17 million metric tons of greenhouse gas (in CO2e). The Division utilized the production forecasts from the GHG Roadmap development process to identify the GHG intensity necessary to achieve the reductions from upstream operations to satisfy § 25-7-105(1)(e)(XII) and (XIII), C.R.S. To ensure steady progress, the Division calculated an interim target for 2027, based upon achieving a 50% reduction from the O&G Sector by 2027 and a 10% reduction from the RCI Sector by 2027.

Under the Division's proposal, upstream sources would be required to submit GHG Intensity Plans by 2023 to set forth how the operators intend to meet the 2025 targets. The Division intends to use the new annual emission reports required by Regulation Number 7, Part D, Sections II.G and V to evaluate compliance with the intensity targets. However, the Division does not believe it has enough information about these annual emission reports to specify exactly how compliance will be demonstrated at this time. For example, the Division believes it will be necessary to adjust the reported emissions to account for the large hydrocarbon emission events detected in this fall's aerial and ground survey work that may be missing or under-reported in the Reg. 7 reports. Therefore, the Division is proposing to return to the Commission in 2023 with a verification proposal. Because the first intensity target in Section IV.B does not apply until 2025, there is sufficient time to allow for a year to study the annual emission reports and account for the aerial and ground survey work, and bring a verification proposal back to the Commission before compliance with the new GHG intensity targets must be demonstrated.

Inventory Revisions

The Division is also proposing revisions to Regulation Number 7, Part D, Section V (the annual emissions reporting program) to ensure the verifiability and enforceability of the proposals described above.

MATERIALS CONTAINED IN THE PROPOSED RULE

The redline-strikeout versions of the proposed revisions to Regulation Numbers 7 and 22 are attached.

PUBLIC MEETINGS/STAKEHOLDER PROCESS

The Division commenced the stakeholder process for this rulemaking in November 2020. The Division held multiple public meetings and listening sessions on November 5, 2020, March 4, March 25, May 11, July 7, August 16 and 31, 2021. On March 17, the Division published an analysis of the strategies under consideration, and received feedback thereon. The Division also held numerous individual meetings with a variety of stakeholders throughout this process, including industry (small and large operators), local governments, environmental groups, community groups, residents and representatives of disproportionately impacted communities, and other air agencies. The Division gave presentations during the development of this rulemaking proposal to the Southern Ute Indian Tribe and the Mountain Ute Tribe in formal consultations. The Division discussed these rulemaking proposals in meetings held with Front Range and Western Slope communities. The Division began sharing draft rule language in July, and received significant feedback from stakeholders prior to submitting this proposal to the Commission.

The Division intends to hold additional public information meetings during the rulemaking process to provide information on the proposed revisions and new requirements as well as provide information about participation in the rulemaking process.

In HB 21-1266, signed into law on July 2, 2021, the General Assembly, determined that "state action to correct environmental injustice is imperative, and state policy can and should improve public health and the environment and improve the overall well-being of all communities… [and] efforts to right past wrongs and move toward environmental justice must focus on disproportionately impacted communities and the voices of their residents." Thus, the state must meaningfully engage disproportionately impacted communities as partners and stakeholders in government decision-making, especially when evaluating potential environmental and climate threats to these communities. In addition to the meetings described, the Division met with leaders and members of communities impacted by oil and gas development. The Division recognizes that much of the analysis and outreach leading up to this proposal occurred prior to HB 21-1266 taking effect, or immediately thereafter; and the Division commits to refining and improving outreach as it works to realize the directives of that bill in the coming months.

The Division will also meet with Division staff as necessary to educate them on the impact and effect of these rule revisions.

BACKGROUND ON THE DEVELOPMENT OF THE RULEMAKING PROPOSAL

What is the problem?

The oil and gas industry is a large source of GHG emissions, and the largest anthropogenic source of methane in Colorado. The proposed revisions will further reduce emissions from Colorado's oil and gas sector, as directed by SB 19-181, SB 19-096, HB 19-1261 and HB 21-1266, through reducing emissions from the midstream and upstream segments, specifically well production facilities, compressor stations, natural gas processing plants, and pipeline systems (gathering/boosting) associated with compressor stations and gas processing plants.

How does this proposed rule help solve the problem?

The proposed rules seek to reduce greenhouse gas (and co-pollutant) emissions from the midstream segment of the O&G sector by requiring control of maintenance emissions, specifically from blowdown events and pigging events. It also seeks to reduce emissions through increased monitoring and LDAR. The Division's proposal will also result in a rulemaking hearing in 2024 to adopt a regulatory program for midstream fuel combustion equipment.

The proposed rules will also reduce greenhouse gas (and co-pollutant) emissions from the upstream segment of the oil and gas sector through the Intensity Plus program. The proposal will also improve the quality of data reported to the Division under 2019's new annual emission reporting program.

Colorado also struggles with ozone pollution, primarily in the front range area (the 8-hour Ozone Control Area). The Division's proposal will meaningfully reduce VOC emissions, which are ozone precursors. The Division's proposal will also significantly reduce ethane emissions. While ethane is not considered a "greenhouse gas" as defined by the EPA or Commission regulations, ethane does have a significant global warming potential. Further, though ethane is not considered a "VOC" as that term is defined by the Clean Air Act or Commission regulations, ethane will react to form ozone. Thus, reductions of VOC and other pollutants such as ethane will address ozone pollution.

How was the rule developed?

Stakeholder input from representatives from industry, consultants, local government agencies, environmental groups, and EPA representatives informed this proposal.

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

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

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

Federal requirements:

Federal law does not prescribe state greenhouse GHG reduction goals. EPA's NSPS OOOOa (40 CFR Part 60, Subpart OOOOa), requires oil and gas operators to reduce VOC and greenhouse gas (in the form of methane) emissions from well facilities, centrifugal compressors, reciprocating compressors, pneumatic controllers, pneumatic pumps, storage vessels, fugitive emissions, and natural gas processing plants. In June 2021, a joint Congressional resolution disapproved 2020 final policy amendments to NSPS OOOO (40 CFR Part 60, Subpart OOOO) and NSPS OOOOa that rescinded all NSPS (regulating emissions of VOCs and methane) from sources in the natural gas transmission and storage segment of the O&G industry and NSPS regulating methane from sources in the industry's production and processing segments. Therefore, these provisions remain in effect. EPA's NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH, may also apply to O&G equipment and operations, but do not specifically require the reduction of GHGs. The Commission's Regulation Number 7 already includes provisions for pneumatic controllers, compressors, pneumatic pumps (in the 8-hour Ozone Control Area), natural gas processing plants (in the 8-hour Ozone Control Area), storage tanks, and LDAR. However, the proposed revisions expand upon some of those requirements and include additional requirements to achieve further reductions in VOCs and GHGs.

Other State (Arizona, New Mexico, Utah) requirements:

Arizona has adopted NSPS Kb, NSPS KKK, NSPS OOOO, NSPS OOOOa, NESHAP HH, and NESHAP HHH as of August 10, 2018. The duties of the Arizona Oil and Gas Conservation Commission (e.g., well drilling and well completions) were transferred to the Arizona Department of Environmental Quality in 2016. The US Bureau of Land Management regulates Arizona's oil and gas production located on Navajo Nation territory.

Utah has adopted NSPS Kb, NSPS KKK, NSPS OOOO, NSPS OOOOa, NESHAP HH, and NESHAP HHH as of May 6, 2021. Utah's Department of Environmental Quality regulates natural gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants. Specifically, Utah's Department of Environmental Quality requires existing pneumatic controllers to meet standards established for new equipment in NSPS OOOO, the use of auto-igniters on flares, bottom or submerged filling for the transfer of intermediate hydrocarbon liquid or produced water at well sites after January 1, 2015, and bottom or submerged filling and vapor capture lines for the transfer of intermediate hydrocarbon liquid or produced water from storage vessels that are required to control emissions under R307-506 (NSPS OOOOa defined storage vessels and centralized tank batteries) after January 1, 2018. Utah also requires some oil and gas sources to submit a triennial emissions inventory. Utah's Division of Natural Resources Oil and Gas Program regulates well drilling and well completions. Utah's Department of Environmental Quality requires self-igniters on flares.

New Mexico has adopted NSPS Kb, NSPS KKK, NSPS OOOO, NSPS OOOOa, NESHAP HH, and NESHAP HHH as of January 15, 2017. The New Mexico Oil Conservation Division regulates well drilling and production. New Mexico also recently adopted a program similar to an intensity program – requiring 98% capture of emissions from oil and gas operations (i.e., allowing a 2% "emission rate"), though New Mexico's requirements include several exceptions for activities

that the Division believes should not be exempt from reduction requirements. New Mexico is currently considering proposed regulations targeting emissions of ozone precursor pollutants from the oil and natural gas sector, including certain provisions similar to the Division's proposal in this action (e.g., the Division's proposals for well unloading and pigging/blowdowns).

How will the rule be implemented?

The amended rules will be published on the Commission's website and emailed to subscribers to the Division's email lists. Division staff will be informed of the revisions to ensure the changes will be reflected in applicable permitting and regulatory actions. The Division staff developing these proposals have been consulting with other Division units and programs to ensure efficient implementation of these new requirements.

Are there time constraints?

Yes, there are time constraints. In the 2019 legislative session, Colorado passed HB 19-1261, the Climate Action Plan to Reduce Pollution (Climate Action Plan), which includes targets of reducing statewide GHG pollution 26% by 2025, 50% by 2030, and 90% by 2050 from 2005 levels. These targets are now statutory requirements that must be met. In HB 21-1266, the Legislature required that the Commission have in place – by January 1, 2022 – regulations to achieve the requirements of 25-7-105(1)(e)(XII), C.R.S., for certain operations in the oil and gas sector. This proposal contains key pieces identified in the Colorado GHG Roadmap to achieve these targets. HB21-1266 also mandates reductions from the 2015 baseline for industrial emissions, which includes certain oil and gas sector emissions. These reductions must be achieved by 2030.

There are also time constraints on the regulated community of the proposed revisions as subject sources will have to implement controls, conduct inspections, and compile records.

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

If the Commission declines to adopt the proposal, the potential emission reductions achievable under the proposed requirements are unlikely to occur. The legislature has acknowledged that climate change impacts Colorado's economy and directed that GHG emissions should be reduced across the many sectors of our economy. Colorado has established specific GHG reduction goals. If Colorado does not adopt the proposed rule, other strategies would need to be identified to meet the statutory directives set forth in Sections 25-7-102(2)(g) and -105(e)(1), C.R.S., established by HB 19-1261 and HB 21-1266.

Range of Regulatory Alternatives

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

The Division considered a number of different regulatory approaches. As was described in the Division's March 25, 2021 stakeholder meeting, the Division considered direct regulation approaches, an intensity program, and two different types of emission reduction programs.
https://drive.google.com/drive/folders/1yvgVG06N57kyCO1GpTgEgsNb6oMJA5Z_

The Division ultimately determined to adopt a hybrid approach to greenhouse gas emission reductions, as calculated to best achieve the state's GHG reduction goals in § 25-7-105(1)(e)(XII) and (XIII), C.R.S. The Division incorporated direct regulations (LDAR, well unloading, pigging/blowdowns, ECD performance testing) and a performance based program (GHG intensity), to provide operators the maximum amount of flexibility in achieving the required reductions, while ensuring the state is on track to meet its GHG targets.

Contact for more information:

Please contact Stefanie Rucker, Supervisor of the Office of Innovation and Planning with the Air Pollution Control Division at 303-692-3188 or at stefanie.rucker@state.co.us with any questions.

Sign up for notifications through the Division's email lists at
https://www.colorado.gov/pacific/cdphe/air-mailing-lists.