BEFORE THE AIR QUALITY CONTROL COMMISSION
STATE OF COLORADO

IN THE MATTER OF PROPOSED REVISIONS TO REGULATION NUMBERS 7 AND REGULATION NUMBER 22
DECEMBER 14-17, 2021 HEARING

ERRATA SHEET OF THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, AIR POLLUTION CONTROL DIVISION

Air Pollution Control Division's Proposal Errata Sheet

The Air Pollution Control Division (Division) last submitted a proposed Statement of Basis and Purpose and rule language as part of the Regulations Number 7 and Number 22 rulemaking hearing on November 23, for the December 14-17, 2021, Air Quality Control Commission meeting.

Throughout the rulemaking process, the Division has continued to work with various parties, negotiating agreeable revisions, highlighted in green, in order to reduce the number of issues on which the Commission must decide. The following revisions have been made to the November 23, 2021, versions of the proposed rule language and Statement of Basis and Purpose.

Regulation Number 7, Part D, Sections II.A.28, II.B.2.h, II.B.2.h.(i)(E), II.H.1.a.(iii), II.H.1.a.(iv), II.H.1.b.(iii), II.H.1.b.(iv), II.H.1.c.(viii), II.H.2.c.(iii), II.H.4.c/II.H.4.c.(i)-(iv), II.H.5.c.(ii), II.I.1.b., and V.C.2.s.(i)

The Division corrects the following typographical and scrivener's errors, and formatting updates and other revisions to conform to the Division's original intent. The revisions in particular to Sections II.H.2.c.(iii) and II.H.4.c.(i) are due to version control.

II.A.28. "Oil and Natural Gas Compression Segment" means the oil and natural gas compression, midstream pipelines, and other equipment used to collect oil and/or natural gas from gas or oil wells and used to compress, dehydrate, sweeten, or transport the oil and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or to a natural gas distribution pipeline. For purposes of Section II., equipment located within the boundaries of a well production facility, including but not limited to compressors, is excluded from the oil and natural gas compression segment.

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II.B.2.h. Beginning February 14, 2022, the owner or operator must conduct performance tests for each enclosed combustion device for which Regulation Number 7, Part D, Sections I.D., II.B.3.b., II.C.1., II.D., or II.F. requires the device to achieve at

least 95% control efficiency for hydrocarbons. A performance test that does not demonstrate that an enclosed combustion device is achieving at least 95% control efficiency for hydrocarbons is considered a failing test.

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II.B.2.h.(i)(E) For the calendar year of a failing performance test, owners or operators must calculate enclosed combustion device emissions (or the emissions for the source controlled) pursuant to Sections II.G. and V. with the results of the failed test until the passing retest under Section II.B.2.h.(i)(c).

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II.H.1.a.(iii) Blowdowns of compressors, where total uncontrolled actual blowdown emissions from all compressors are greater than or equal to 0.75 tpy VOC or 1.5 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation. Hydrocarbons emitted during a compressor blowdown event where the physical volume of the compressor is less than fifty (50) cubic feet (cf) are not included in the emissions calculated for purposes of applicability of this Section II.H.1.a.(iii), provided the owner or operator maintains records of the dates and number of such events.

II.H.1.a.(iv) Blowdowns of all equipment and piping not covered by Sections II.H.1.a.(i) through II.H.1.a.(iii) where the physical volume between isolation valves is greater than or equal to fifty (50) cf. This requirement does not apply if the owner or operator can demonstrate that the aggregate uncontrolled actual emissions from blowdowns of all equipment and piping subject to this Section II.H.1.a.(iv) are less than 0.75 tpy VOC and 1.5 tpy methane, provided the owner or operator maintains records of the dates and number of all blowdowns including blowdowns where the physical volume between isolation valves is less than fifty (50) cf.

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II.H.1.b.(iii) Blowdowns of compressors, where total uncontrolled actual blowdown emissions from all compressors are greater than or equal to 1 tpy VOC or 2 tpy methane on a rolling 12-month basis, consistent with a Division-accepted method of calculation. Hydrocarbons emitted during a compressor blowdown event where the physical volume of the compressor is less than fifty (50) cf are not included in the emissions calculated for purposes of applicability of this Section II.H.1.b.(iii), provided the owner or operator maintains records of the dates and number of such events.

II.H.1.b.(iv) Blowdowns of equipment and piping not covered by Sections II.H.1.b.(i) through II.H.1.b.(iii) where the physical volume between isolation valves is greater than or equal to fifty (50) cf. This requirement does not apply if the owner or operator can demonstrate that the aggregate uncontrolled actual emissions from blowdowns of all equipment and piping subject to this Section II.H.1.a.(iv) are less than 1 tpy VOC and 2 tpy methane, provided the owner or operator maintains records of the dates and number of all blowdowns including blowdowns where the physical volume between isolation valves is less than fifty (50) cf.

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II.H.1.c.(viii) Within sixty (60) days of the first day of the month after which blowdowns of compressors or other equipment and piping with a physical volume of the compressor or between isolation valves of equal to or greater than 50 cf located at a natural gas compressor station or natural gas processing plant not located in a disproportionately impacted community not subject to Sections II.H.1.b.(iii) or II.H.1.b.(iv) increases hydrocarbon emissions to 1 tpy VOC or 2 tpy methane after the applicable compliance date in Sections II.H.1.c.(i) through II.H.1.c.(iv), on a rolling twelve-month basis.

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II.H.2.c.(iii) A pigging unit not subject to Section II.H.2.c.(i) as of January 1, 2024, that increases hydrocarbon emissions to 1 tpy VOC or 2 tpy methane must be in compliance with Section II.H.2.c. within sixty (60) days of the first day of the month after which the emissions exceeded the applicable threshold, based on a rolling twelve-month basis.

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~~II.H.4.c.(i) Connecting each high pressure pig launcher or receiver by jumper lines to a low pressure gathering line and operating jumper lines to depressurize such pig launchers and receivers prior to opening the pig launcher or receiver hatch.~~

II.H.4.c. Where feasible ~~F~~For pipeline blowdowns other than for pigging operations, rerouting gas to the low-pressure system using existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems.

II.H.4.c.(i) For purposes of Section II.H.4.c., feasibility requires that a low-pressure line be nearby, be owned or operated by the same midstream owner or operator, and be on contiguous property owned or operated by the midstream owner or operator. Feasibility here also means that the action is economically feasible.

II.H.4.c.(ii) The Division can approve alternatives to the best practices in Section II.H.4.c. where the owner or operator demonstrates that the alternatives will achieve equivalent or better emission reductions.

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II.H.5.c.(ii) The date, location, identification of equipment or piping and number of blowdown events (other than pigging operations), including identification of whether the volume between isolation valves is less than 50 cf.

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II.I.1.b. The owner or operator must take action(s) to mitigate emissions from leaks placed on delay of repair where technically feasible.

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V.C.2.s.(i) Beginning with the June 2024 report for calendar year 2023, capture or control methods or best practices employed pursuant to Sections II.H.1., II.H.2., or II.H.4. per pigging unit.

Regulation Number 7, Part D, Section II.B.2.h.(i)(D)

The Division revised the timeline for installation of a flow meter prior to a performance test to address industry concerns with vendor availability and implementation resources.

II.B.2.h.(i)(D) With enough time to calibrate and ensure proper reading from the flow meter prior to each performance test conducted under Section II.B.2.h. and continuing through the performance test, owner or operators must install and operate a flow meter on the inlet to each enclosed combustion device to be tested, unless not required by the Division-approved performance test protocol. Temporary flow meters may be used to meet this requirement.

Regulation Number 7, Part D, Sections II.G.1.c.(vi)(A), II.G.1.d.(iii) and II.G.2.c.(ii)

The Division revised Section II.G.1.c.(vi)(A) to reflect that artificial lift is not required on any well, regardless of commencement of operation date, where the structure of the well renders artificial lift infeasible. The Division revised the notice in Section II.G.1.d.(iii) required to align with COGCC requirements and to clarify the contents of the notice. The Division revised Section II.G.2.c.(ii) to reflect that the recordkeeping of lift cycles was intended to relate to plunger lifts.

II.G.1.c.(vi)(A) Artificial lift is not required where an operator demonstrates to the Division that installation and use of artificial lift is technically infeasible on a well ~~that commenced operation prior to February 14, 2022~~ because of the structure of the well.

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II.G.1.d.(iii) Well liquids unloading events are not included in the calculation for purposes of Section II.G.1.d.(ii) where the need for well liquids unloading resulted from the infiltration of excess water directly caused by a nearby hydraulic fracturing event provided that the owner of the well to be unloaded provides the Division with at least 48 hours written notice (or as soon as possible prior to conducting well liquids unloading if 48 hours' notice would require an alternative or extended well liquids unloading practice that increases emissions) of the intent to begin unloading and the unloading activities are completed within thirty (30) days of commencement of those activities. The notice must include an identification of the operator that conducted the fracturing event suspected of contributing to the infiltration of water and the well API number(s) of the well that was fractured.

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II.G.2.c.(ii) The type of artificial lift used to reduce emissions pursuant to Section II.G.1.c.(vi); the number of well liquids unloading and well swabbing events resulting in emissions to atmosphere; or, if applicable, documentation of the justification for not having artificial lift under Section II.G.1.c.(vi). If plunger lift is installed, the number of cycles of the plunger.

Regulation Number 7, Part D, Section V.C.2.d.(viii)

The Division revised Section V.C.2.d.(viii) to align more accurately with Section II.H.

V.C.2.d.(viii) Beginning with the June 2024 report for calendar year 2023, best ~~management~~ practices employed pursuant to Section II.H.4~~, per blowdown event~~.

Regulation Number 7, Statement of Basis and Purpose, pages 7, 10, 14 and 15

The Division corrects the following typographical and scrivener's errors, and other revisions to conform to the Division's intent.

Given the evolving and innovative work and study in this area to evaluate the performance of enclosed combustion device~~e~~s, the Commission

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The Commission was presented with data reported to EPA and to the Division that generally agrees that the largest sources of greenhouse gas emissions from the midstream segment is the fuel combustion equipment; however, these data sets also agree that emissions (particularly methane emissions) from operations and maintenance activities - such as pigging and blowdowns - are significant, and, the Commission has determined they are cost-effective to address. The Commission recognizes that depressurizing pig launchers and receivers or blowing down compressors and other equipment in natural gas gathering operations can emit VOCs. Emissions associated with the removal of oxygen from equipment to place equipment into service after a blowdown are not subject to Section II.H. in order to safely operate the equipment. This gas released from pigging and blowdown activities is under the same pressure as the pipeline and contains methane, ethane, and VOCs including benzene, toluene, ethylbenzene, and xylene. Pig receivers can also contain collected condensate liquid that had accumulated in the pipeline.

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In Section V.C.2.d., beginning with the June 2024 report for calendar year 2023, the Commission requires owners or operators to report emissions, along with other supporting information, resulting from blowdowns from facility equipment and piping where the physical volume of the piping between isolation valves is greater than or equal to 1 cubic foot.

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EPA also asks states to consider environmental justice as part of their actions, though there are no specific federal regulatory requirements at this time. ~~In this revision, Part B, Sections III and IV,~~ These revisions expand on environmental justice considerations by incorporating the definition of "disproportionately impacted communities" (DI Community), and seeking to prioritize reductions in DI communities.

Regulation Number 7, Statement of Basis and Purpose, page 4

The Division provides additional clarification concerning the applicability of the performance testing requirements in Section I.

The Commission adopted language corresponding to the recommendations in the EPA's Oil and Gas CTG and provides the following clarifications as related to purpose, intent, and terminology. Concerning the purpose of the performance test, EPA's Oil and Gas CTG recommends the performance test to demonstrate compliance with the recommended level of control, which is a 95% reduction of VOC emissions from storage vessels and a 95% reduction of VOC emissions from centrifugal compressor wet seal fluid degassing systems. As EPA discusses in the Oil and Gas CTG, if an owner or operator complies with the recommended RACT by using a combustion device, initial and periodic performance testing of the device is recommended. The performance test will demonstrate that the combustion device reduces the mass content of VOC in the gases vented to the device by at least 95% by weight.

Concerning the terms "potential for VOC emissions" and "(controlled actual emissions)" in the storage vessel applicability provision, the Commission adopted language corresponding to the recommended applicability provision in EPA's Oil and Gas CTG, which is based on EPA's NSPS OOOO and OOOOa. The Commission included the phrase "(controlled actual emissions)" in recognition of more extensive storage tank control requirements in Section I., as related to the recommendations in EPA's Oil and Gas CTG for storage vessels, and not to allow and operator to use a different calculation methodology than that used to determine the storage vessel's potential for VOC emissions. The Commission intends for the Division to determine whether storage vessels are subject to the performance testing requirement adopted in this December 2021 rulemaking, in the same manner the Division currently determines whether a storage vessel is subject to NSPS OOOO, including averaging emissions across the number of storage vessels in the battery as included in EPA's NSPS.

Regulation Number 22, Part B, Sections III.A.9, III.A.13, III.C.2.a., III.D.6., III.D.7., IV.A.13, IV.C.3., IV.E.1.d., and IV.F.1.e.

The Division corrects the following typographical or scrivener's errors, and other revisions to conform to the Division's intent.

III.A.9. "Midstream steering committee" means a committee comprised of members approved by the Division to serve as a technical working group tasked with developing program guidance documents and developing a midstream segment emission reduction plan. To the extent practicable, the committee members will include two members representing the electric utility sector; three members representing the midstream segment (at least one representing the oil and natural gas compression segment and one representing the natural gas processing segment), or industry trade organizations representing owners or operators; at least three local government representatives (one from inside the 8-hour ozone control area and northern Weld County and one from outside the 8-hour ozone control area and northern Weld County); at least three members representing the general public (including a representative of an environmental organizations and a representative of a disproportionately impacted community); and at least one Division staff person. The steering committee may also include two additional members: a representative from the Colorado Energy Office and a representative from the Public Utilities Commission.

III.A.13. "Oil and natural gas compression segment" means the oil and natural gas compression, midstream pipelines, and other equipment used to collect oil and/or natural gas from gas or oil wells and used to compress, dehydrate, sweeten, or

transport the oil and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or to a natural gas distribution pipeline. For purposes of Section III., equipment located at a well production facility, including but not limited to compressors, is excluded from the oil and natural gas compression segment.

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III.C.2.a. The midstream steering committee will seek publicly available information concerning most recently filed electric utility Electric Resource Plans and Clean Energy Plans, regarding the forecast timing of upcoming Electric Resource Plan filings, electric utility energy sales and demand forecasts for 2023 through 2030, and regarding existing and contracted electric generation units, and approved future transmission lines in Colorado.

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III.D.6. Following receipt of the midstream segment ERP from the midstream steering committee, the Division will make the draft midstream segment ERP available for at least 30 days of public comment.

III.D.7. By no later than August 31, 2024, the Division will submit a regulatory proposal based upon the midstream segment ERP to the Air Quality Control Commission and request a rulemaking hearing for no later than December 31, 2024.

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IV.A.13. "Intensity operator" means a person or entity that operates upstream segment activities or equipment. For purposes of Section IV., where a person or entity holds a controlling interest in more than one intensity operator, that person or entity is the intensity operator of all upstream segment activities and equipment in which that person or entity has a controlling interest.

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IV.C.3. For calendar years 2026 through 2027, the new facility intensity target is 6.64 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 6.0 mtCO2e/kBOE

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IV.E.1.d. An estimate of the greenhouse gas emission reductions that each type of BMP, control method, emission reduction strategy, or technology is expected to achieve on a company-wide mass basis and on a company-wide greenhouse gas intensity basis, including calculation methods.

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IV.F.1.e. Include recommendations to evaluate total greenhouse gas emissions relative to the applicable baseline and progress towards statewide greenhouse gas emission reduction goals for oil and gas emissions in Section 25-7-105(1)(e)(XII) and (XIII), CRS.

Regulation Number 22, Part B, Section III.C.3.

The Division clarifies the purpose of the provided information.

III.C.3. By no later than July 31, 2022, each midstream segment owner or operator must provide the following information to the midstream steering committee on a Division-approved form to inform the guidance document that will be developed pursuant to Section III.D.1.

Regulation Number 22, Part B, Sections III.C.2.a., III.C.3.c., III.C.3.e., and III.C.3.f., and the Regulation Number 22 Statement of Basis and Purpose, page 5

The Division clarifies the information sought by or provided to the midstream steering committee, to address questions and concerns raised by the utilities and midstream operators.

III.C.2.a. The midstream steering committee will seek publicly available information concerning most recently filed electric utility Electric Resource Plans and Clean Energy Plans, information regarding the forecast timing of upcoming Electric Resource Plan filings, electric utility energy sales and demand forecasts for 2023 through 2030, information regarding existing and contracted electric generation units, and approved future transmission lines in Colorado.

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III.C.3.c. An estimate of the total annual power demand, along with total instantaneous power demand in kilowatt hours, or horsepower demand required for use of the midstream fuel combustion equipment identified in Section III.C.3.b.

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III.C.3.e. An estimate of the total annual kilowatt hours and heat rate demand, along with total instantaneous power demand, being supplied by electric motors and electric heaters identified in Section III.C.3.d.

III.C.3.f. An estimate of existing transmission and distribution capacity to serve estimated load in a specific location as supplied by the applicable electric, transmission, or distribution service provider.

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The rules adopted by the Commission mandate that midstream segment owners and operators submit certain specified information to the steering committee by July 31, 2022. This information must include an identification of all fuel combustion equipment owned or operated by each midstream segment operator. There is no de minimis equipment that should not be identified, though not all equipment may end up in the operator's ERP or the segment ERP. This information should also allow the steering committee to easily understand what equipment - and how much emissions - are located within disproportionately impacted communities. Owners and operators must all include an estimate of the total annual power demand required for use of all midstream combustion equipment owned or operated by each midstream segment operator. When reporting this estimate, the owners and operators should identify whether such equipment is required to run continuously or whether operation of certain equipment is intermittent or

interruptible. Owners and operators are also required to seek an estimate of existing transmission and/or distribution capacity to serve the estimated electric load (i.e. total power demand) at the specific locations of the midstream segment fuel combustion equipment, and provide that information to the steering committee. Transmission and/or distribution capacity should be obtained from the appropriate electric utility, transmission, or distribution service provider and reported to the steering committee when made available by the utility or utilities. Owners and operators should evaluate whether their midstream segment fuel combustion equipment operations require firm or non-firm transmission service. Should an owner or operator consider potential electrification, the Commission intends the owner or operator will continue to engage with the appropriate electric utility, transmission, or distribution service provider… The rules provide that such additional information should be requested by April 30, 2022; however, this does not limit the Division's authority to use existing statutes and regulatory authority to require the submittal of additional information to the Division~~or the midstream steering committee~~.

Regulation Number 22, Part B, Section IV.B.7.b.

The Division clarifies the applicability of greenhouse gas intensity targets in the years subsequent to the acquisition.

> IV.B.7.b. If a minority operator acquires or takes over operation of an oil or natural gas well in Colorado from a majority operator on or after January 1, 2025, the minority operator must at least comply with the applicable minority operator greenhouse gas intensity target for the preproduction and production emissions from the acquired well(s) for the calendar years of and after the acquisition, after which the minority operator greenhouse gas intensity targets apply to all assets of the minority operator, including the acquired assets (unless the minority operator has become a majority operator.

Regulation Number 22, Statement of Basis and Purpose, pages 7, 8, and 9

The Division clarifies and corrects the following typographical and scrivener's errors, and other changes to reflect the Division's intent.

Calculating Intensity

The Commission, for consistency across Colorado operations, determined that in converting natural gas production to barrels of oil equivalent, owners and operators should use the conversion factor of 5800 standard cubic feet of natural gas per barrel of oil equivalent. To clarify the calculation for intensity, which requires use of oil and natural gas production in thousand barrels of oil equivalent (kBOE), as well as the common units used for reporting natural gas production of million standard cubic feet (MMscf), operators should divide natural gas production reported in MMscf by 5.8 MMscf/kBOE. The equation for calculating total production in kBOE is:

> TP (kBOE) =[NGP (MMscf)/5.8 (MMscf/kBOE)] + [OP (bbl)/1000 (bbl/kBOE)]
>
> where: TP (kBOE) = total annual production of natural gas and oil in the units of kBOE
>
> NGP(MMscf) = annual natural gas production in the units of million standard cubic feet
>
> OP (bbl) = annual oil production in the units of barrels of oil

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If, at any point, a minority operator has production over 10,000 kBOE, or if a minority operator increases its production by 2,500 kBOE over the prior calendar year production - then in the calendar year after the

acquisition, the minority operator would become a majority operator and be subject to those targets (and other rules applicable to majority operators).

Otherwise, if a minority operator acquires assets (or merges with) a minority operator, the minority targets must be met in the year of the acquisition for all assets, including the acquired assets. If a majority operator sells assets, the majority operator targets must still be met, even if that operator's production falls below 10,000 kBOE. If a new to market operator acquires the assets of a minority operator, the new to market operator becomes a minority operator and the minority operator targets apply; similarly, if a new to market operator acquires the assets of a majority operator, the majority operator targets apply.

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Verification

In Section IV.F., the Commission directs the Division to develop a mechanism to track progress towards meeting the state's GHG reduction goals and to evaluate compliance with the greenhouse gas intensity targets and new facility intensity targets in Sections IV.B. and IV.C. The Commission determined that it was advisable to give the Division time in 2021 and 2022 (1) to evaluate the annual emission reports submitted in 2021 and 2022, (2) to evaluate different calculation and emission quantification methodologies for different emitting activities and equipment, and (3) to consider the impact and results of the aerial and ground-based survey work being conducted by the Division (and contractors) in 2021 (because this data will not be fully available until the spring of 2022) as well as other relevant surveys. …