Decision No. C21-0610

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21R-0449G

IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-4, RELATING TO GAS UTILITY PLANNING AND IMPLEMENTING SB 21-264 REGARDING CLEAN HEAT PLANS AND HB 21-1238 REGARDING DEMAND SIDE MANAGEMENT.

NOTICE OF PROPOSED RULEMAKING

Mailed Date: October 1, 2021
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I. <u>BY THE COMMISSION</u>

A. Statement

1. The Colorado Public Utilities Commission issues this Notice of Proposed Rulemaking (NOPR) to amend the Commission's Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* (CCR) 723-4 (Gas Rules). The proposed amendments would add to as well as revise the existing provisions of the Commission's Gas Rules. As relevant here, the Gas Rules apply to all jurisdictional gas utilities and to all Commission proceedings concerning

such utilities. Through this rulemaking, the Commission intends to establish new rule regulatory requirements for gas utility planning, implement numerous statutory changes and additions adopted in the 2021 Colorado legislative session, and fulfill the express rulemaking requirements placed on the Commission.

2. Among other purposes, this rulemaking is intended to satisfy the requirements of Senate Bill (SB) 21-264, enacted and effective on June 24, 2021, and codified as § 40-3.2-108, C.R.S. SB 21-264 requires Colorado gas utilities with more than 90,000 retail customers to develop comprehensive Clean Heat Plans (CHPs) designed to achieve greenhouse gas emissions reductions. This rulemaking is also intended to satisfy the requirements of House Bill (HB) 21-1238, enacted on June 24, 2021 and effective on September 6, 2021, codified in §§ 40-3.2-103, 40-3.2-106, and 40-3.2-107, C.R.S. HB 21-1238 primarily modifies the statutory provisions governing gas utility demand side management (DSM).

3. As relevant here, § 40-3.2-108(5), C.R.S., requires the Commission to undertake a rulemaking by October 1, 2021, proposing to update its (DSM) rules consistent with the new CHP-oriented clean heat targets established in SB 21-264. The NOPR issued in this Proceeding satisfies this requirement.

4. The proposed changes to the Gas Rules are set forth in legislative (*i.e.*, strikeout and underline) format (Attachment A) and final format (Attachment B).

5. Through this NOPR, the Commission solicits comments on possible changes to the Gas Rules as described here and in Attachments A and B and schedules an initial rulemaking hearing. Interested persons will have an opportunity to submit written comments on the proposed rules and to provide oral comment at the scheduled hearing. The Commission welcomes the submission of alternative proposed rules and/or additional related rules,

including both individual proposals and consensus proposals joined by multiple stakeholders. Participants are encouraged to provide redlined rules along with their written comments.

B. Background

1. Statutory Changes Adopted in 2021 Colorado Legislative Session

a. SB 21-264: Concerning the Adoption of Programs by Gas Utilities to Reduce Greenhouse Gas Emissions

6. As noted above, SB 21-264, codified as § 40-3.2-108, C.R.S., requires Colorado gas utilities with more than 90,000 retail customers to develop, file, and receive approval of comprehensive CHPs designed to achieve greenhouse gas emission reductions, specifically the reduction of carbon dioxide and methane emissions from gas distribution systems and the associated end-use consumption.

7. Section 40-3.2-108(3), C.R.S., requires gas utilities to file CHPs to demonstrate the utility will achieve greenhouse gas emissions reduction targets of 4 percent by 2025 and 22 percent by 2030, based on 2015 emission levels, from a range of prescribed clean heat resources. Gas utilities are required to file, as part of their applications, projections of baseline and forecasted greenhouse gas emissions from the use of gas by their customers and from methane emissions in their facilities.

8. Section 40-3.2-108(4), C.R.S., requires the state's largest investor-owned gas utility, Public Service Company of Colorado, to file its first CHP application by August 1, 2023, and thereafter not less than every four years, for a planning period of not less than five years. All other Colorado gas utilities must file their initial CHP applications by January 1, 2024, with similar guidelines. The applications must include: (1) a portfolio that uses clean heat resources to the maximum practicable extent, that complies with the 2.5 percent annual cost cap and that

may or may not meet the clean heat target in the applicable plan period but that demonstrates reductions in methane emissions; (2) a portfolio that meets the emissions reduction targets for the plan period using only clean heat resources but *does not have to comply* with a 2.5 percent annual cost cap; (3) other portfolios at the utility's discretion; and (4) other portfolios as may be directed by the Commission. In addition to these portfolios, the statute prescribes minimum required application components including, among others: the maximum amount of greenhouse gas reductions counting toward the CHP target that can be achieved through the use of recovered methane; projected annual greenhouse gas emissions and carbon dioxide and methane reductions; a program budget; priority for investments that ensure disproportionately impacted communities or income-qualified customers benefit from the investments; quantification of additional air quality, environmental, and health benefits; and a forecast of potential new customers or expansion of the utility's gas system during the plan period and related projected greenhouse gas emissions.

9. As noted above, § 40-3.2-108(5), C.R.S., requires the Commission to undertake a rulemaking to update its DSM rules consistent with the CHP-oriented clean heat targets by October 1, 2021. The statute requires the Commission to convene at least four workshops or public meetings as part of the rulemaking. The statute directs the Commission to adopt final rules by December 1, 2022. Through this NOPR, the Commission schedules the first of such public meetings; additional meetings will be scheduled by a separate order issued in this Proceeding.

10. Section 40-3.2-108(6), C.R.S., outlines the standards for Commission approval of a utility's CHP application and related cost recovery.

11. Section 40-3.2-108(7), C.R.S., establishes annual reporting requirements for gas utilities including emissions reduced and money expended implementing approved CHPs. This section also requires that the Commission, by December 1, 2032, establish further emissions reduction targets for 2040, 2045, and 2050 proportional to the reduction goals for the residential, commercial, and industrial sectors established by the Colorado Department of Public Health and Environment (CDPHE) and its Air Quality Control Commission (AQCC). The Commission notes that those further reduction goals will be established in accordance with the overall statewide greenhouse gas pollution reduction goals previously established in HB 19-1261, enacted on May 30, 2019, which amended §§ 25-7-102, -103, and -105, C.R.S. HB 19-1261 sets statewide reduction goals of 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, as measured relative to 2005 statewide levels. *See* § 25-7-102(2)(g), C.R.S. While the new CHP-related requirements in § 40-3.2-108(7), C.R.S., for 2040 through 2050 may be viewed as generally consistent with HB 19-1261, harmonizing the specific requirements in these statutes will require further review by the Commission.

12. Section 40-3.2-108(8), C.R.S., outlines requirements for employment and gas utility workforce associated with CHP implementation

13. Section 40-3.2-108(9), C.R.S., establishes CHP application requirements for “small” gas utilities (*i.e.*, gas utilities with less than 90,000 retail customers).

14. Sections 40-3.2-108(10) and 40-3.2-108(11), C.R.S., require the Commission to determine mass-based greenhouse gas emissions reduction targets for 2035 by December 1, 2024, and for 2040, 2045, and 2050, by December 1, 2032, respectively.

b. HB 21-1238: *Concerning the Modernization of Gas Energy Efficiency Programs*

15. HB 21-1238 expands the definition of DSM programs to include weatherization and insulation and high efficiency beneficial electrification. HB 21-1238 also revises DSM program cost-effectiveness to include the social costs of carbon and methane and establishes values for each pollutant.

16. Section 40-3.2-103, C.R.S., requires gas utilities, starting in 2022 and recurring no less than every four years thereafter, to file applications to open a “DSM Strategic Issues” proceeding. The statute directs the purpose of such proceedings will be to develop energy savings targets to be achieved by the gas utility, taking into account, its potential for cost-effective DSM as well as statewide greenhouse gas emissions reduction goals. The statute directs the Commission, as part of approving the utility’s application, to develop an estimated DSM budget commensurate with the natural gas savings targets, establish funding and cost-recovery mechanisms, and develop a financial bonus structure for DSM programs implemented by the gas utility.

17. Section 40-3.2-103(3), C.R.S., requires gas utilities to develop implementation plans consistent with the savings targets established in their approved DSM Strategic Issues application, and allows gas DSM plans to be combined with electric DSM plans, beneficial electrification plans, or other utility plans that reduce energy consumption or greenhouse gas emissions.

18. Section 40-3.2-106, C.R.S., requires gas and electric utilities to consider the social cost of carbon when planning and evaluating their DSM programs, resets the 2020 social cost of carbon at $68 per short ton, and defines a discount rate of 2.5 percent or less for program evaluation.

19. Section 40-3.2-107, C.R.S., requires gas utilities, with Commission oversight, to consider the social cost of methane in planning and evaluating their DSM programs, sets that value to not less than $1,756 per short ton, and defines a discount rate of 2.5 percent or less for program evaluation. The statute also requires the Commission, when calculating the cost of methane emissions, to obtain and apply the best available values for gas leakage during extraction, processing, transport, and delivery phases prior to consumption.

20. HB 21-1238 also establishes minimum expenditure targets for income-qualified customers in gas utilities' DSM programs. The statute requires that at least 25 percent of overall residential gas DSM program expenditures be targeted at serving residential customers in income-qualified households. For utilities serving fewer than 50,000 full-service customers, at least 15 percent of overall residential gas DSM program expenditures must be targeted at serving residential customers in income-qualified households. On or after January 1, 2026, the Commission may adjust these percentages to reflect changed circumstances, so long as the resulting percentages represent a significant portion of gas DSM program expenditures and align with the state's efficiency and greenhouse gas emissions reduction goals. These requirements are codified in § 40-3.2-103(3)(a)(II) – (IV), C.R.S.

2. Relevant Prior Commission Proceedings

a. Proceeding No. 20M-0439G: Repository for Investigating Retail Gas Greenhouse Gas Emissions

21. In November of 2020, the Commission opened a non-adjudicatory administrative proceeding to serve as a repository for presentations, comments, and other materials relating to the Commission's general investigation of retail natural gas industry greenhouse gas emissions in light of the statewide greenhouse gas emissions reduction goals adopted in then-recent HB 19-1261. *See* Decision No. C20-0770, issued November 4, 2020, in Proceeding

No. 20M-0439G. HB 19-1261, codified at § 25-7-102, C.R.S., sets statewide goals to reduce 2025 greenhouse gas emissions by at least 26 percent; 2030 greenhouse gas emissions by at least 50 percent; and 2050 greenhouse gas emissions by at least 90 percent of the levels of statewide greenhouse gas emissions that existed in 2005. In addition to the statutory reductions, the statute explains that one of the purposes of the legislation is to "require the use of all available practical methods which are technologically feasible and economically reasonable so as to reduce, prevent, and control air pollution throughout the state of Colorado." § 25-7-102(1), C.R.S.

22. The Commission subsequently held several Commissioners' Information Meetings on this topic to solicit information from subject matter experts. The information presented at those meetings and submitted in connection therewith has been collected electronically in Proceeding No. 20M-0439G.

b. Proceeding No. 21M-0168G: Petition for Short-Term Infrastructure Planning Rulemaking

23. Earlier this year, the Commission considered a joint petition filed by the Colorado gas utilities, Staff of the Colorado Public Utilities Commission (Staff), the Colorado Office of the Utility Consumer Advocate,[1] and the Colorado Energy Office (CEO) requesting the Commission open a rulemaking to implement the filing parties' proposed short-term gas infrastructure planning rules for Colorado gas utilities (Joint Petition).

24. By Decision No. C21-0446, issued July 23, 2021, in Proceeding No. 21M-0168G, the Commission denied the Joint Petition. In its decision, the Commission explained that it found it more appropriate at this time, rather than to proceed with the requested narrow

[1] The current name of the joining party, the "Office of Consumer Counsel," has changed to the "Office of the Utility Consumer Advocate."

rulemaking focused on short-term planning, to develop a broader range of rules for consideration in a more comprehensive rulemaking. The Commission noted that such broader rulemaking would provide an opportunity to consider rule revisions and additions addressing not only the short-term planning contemplated in the Joint Petition but also long-term planning and those issues arising from the new legislation passed in the 2021 Colorado legislative session.

c. Ongoing Issues Relating to Utility Infrastructure Investments

25. In addition, we note the Commission has recently reviewed and continues to review applications and rate case filings that address substantial investments by Colorado gas utilities to replace and renew their system infrastructure, including reliability and system integrity investment. Generally, Colorado utilities contend reliability and system integrity investments are necessary to provide safe and reliable utility service to customers and to meet current and near-final updates to federal safety regulations developed by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).[2] However, the utility investment programs that address PHMSA requirements predate the enactment of HB 19-1261 and its goal for a statewide reduction in greenhouse gas emissions of 90 percent by 2050. We recognize that state-mandated required greenhouse gas emission reductions will inevitably have an impact on the gas utility's investments, sales, depreciation schedules, revenue requirements, and rates.

26. As explained below in relation to the proposed Gas Planning Rules, recent utility proceedings addressing the recovery of system safety and integrity investments through rate riders have raised many issues surrounding the transparency of planning and cumulative

[2] *See* Proceeding Nos. 19AL-0075G, 20A-0379G, 20AL-0049G, 21A-0071G, and 21AL-0236G.

investment and expenditures in both the short- and long-terms. The proposed Gas Planning Rules are intended to enhance the visibility into a gas utility's future projects and expenditures while also promoting the public interest.

3. Pre-Rulemaking Comment and Information in Proceeding No. 21M-0395G

27. Most recently, on August 25, 2021, the Commission initiated a miscellaneous proceeding, Proceeding No. 21M-0395G, to fulfill two primary purposes: (1) initially, to collect comment and information from Colorado utilities and interested stakeholders regarding the immediate development of a notice of proposed rulemaking to issue by October 1, 2021, in accordance with the rulemaking requirements in SB 21-264 and HB 21-1238; and (2) further, to collect additional comment and information regarding gas utility short-term and long-term planning and the need to develop and issue a supplemental NOPR within the aforementioned rulemaking in order to fulfill the requirements placed on the Commission by the statutes adopted in the 2021 Colorado legislative session. *See* Decision No. C21-0516, issued August 25, 2021, in Proceeding No. 21M-0395G. The Commission also requested that Colorado gas utilities develop and submit in Proceeding No. 21M-0395G, long-term rate projections so that the Commission and participating stakeholders can more fully comprehend the potential impact of the Commission's rulemaking efforts in light of other utility investment activity.

a. Initial Comments

28. Through Decision No. C21-0516, the Commission solicited comments and proposed rule changes from utilities and interested stakeholders on the following topics:

a) Regarding the filing of integrated CHP and DSM applications, to what extent and how should the Commission require utilities to: (i) foster competition and innovation that may be available from the marketplace; (ii) compare

DSM, beneficial electrification, renewable natural gas, hydrogen, and other options on a consistent basis; (iii) establish DSM parameters to qualify as a CHP initiative; and (iv) facilitate procedural efficiency among the application filings?

b) How should the Commission evaluate long-term rate impacts – as well as underlying factors such as rate base investment, expensed costs, and retail sales – given the wide array of potential outcomes on DSM investment, beneficial electrification, alternative supply sources, and system integrity investment? What duration should such evaluations cover?

c) SB 21-264 prescribes certain technologies as clean heat resources, but also provides the Commission broad discretion to set other technologies as potential clean heat resources. Are there other technologies or resources (*e.g.*, responsibly-sourced gas) that the Commission should be considering when designing rules?

d) What data, quantification methodologies, or measurement technologies are available to ensure consistent and accurate accounting of gas utility carbon emissions and methane leakage including calculation of the 2015 baseline?

e) How should the Commission treat gas utility DSM, leakage reduction, or fuel switching investment made during or after 2015 for: (i) the crediting of emission reductions relative to the 2015 baseline; and (ii) the accounting of costs against the retail rate cap?

f) Given the time constraint of meeting 2025 and 2030 emission reduction targets, should the Commission: (i) allow combined 2025 and 2030 CHP applications; (ii) implement a less-than-fully-adjudicated process for 2025 CHP applications; or (iii) implement the DSM and CHP processes in a specific manner to promote procedural efficiency?

g) Is the current comprehension of hydrogen integration in pipeline systems sufficient to allow its safe introduction into Colorado gas operations? How and at what level should the Commission set hydrogen integration? How should the Commission monitor and protect against potential infrastructure embrittlement?

h) To what extent do the questions herein (as well as others that arise) need to be answered in a rulemaking, in the miscellaneous proceeding opened by this order, or via the adjudication of specific applications?

i) Should Colorado gas utilities receive credit for the emission reductions induced by electric utility beneficial electrification programs and efforts? How should Colorado gas utility DSM and CHP plans incorporate overlapping electric utility beneficial electrification plans?

j) Among other U.S. states that have imposed similar decarbonization goals or regulations on the natural gas industry, which states and/or utilities offer noteworthy examples for cost effective regulated investments, incentives, and/or customer education and outreach?

k) In an effort to improve equity and better serve disproportionately impacted communities, what standards could the Commission set for outreach, input, and stakeholder participation for CHP and any other specific gas proceedings? What standards should the Commission set for DSM or beneficial electrification program participation?

l) In addition to lower [greenhouse gas emissions], how should the Commission consider potential additional air quality, environmental, and health benefits of clean heat technologies?

m) Should the Commission interpret the cap on recovered methane (1 percent by 2025, 5 percent by 2030) referenced in § 40-3.2-108(3), C.R.S., as a percent of total emissions or a percent of total emission *reductions*?

n) Since the calculations of [greenhouse gas emissions] inherently exclude those associated with transport customers, how can the Commission ensure that utilities do not transition commercial customers to transport customers as a strategy to reduce future year emissions relative to the baseline?

o) What steps should the Commission take to evaluate and track the costs and benefits of renewable natural gas and green hydrogen products?

p) Please provide, if available, a redline markup of the Commission's Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* 723-4, relevant to the issues raised in this Proceeding.

q) Describe any other factors the Commission should assess when evaluating Colorado gas utility CHP and DSM applications under the new statute, and what information is needed from utility applicants in order to evaluate these additional factors.

r) What criteria should the Commission consider in determining if methane leakage reduction investments represent cost-effective emissions reduction strategies, both in a stand-alone sense and when compared to other emission reduction strategies?[3]

29. Responsive comments were filed on September 10, 2021 by Colorado gas utilities Public Service Company of Colorado, Black Hills Colorado Gas, Inc., Colorado Natural Gas, Inc., and Atmos Energy Corporation; by Staff, CEO, and RMI; and by stakeholder interest

[3] Proceeding No. 21M-0395G, Decision No. C21-0516 at ¶ 23. (Emphasis in Original)

groups Natural Resources Defense Council, Western Resources Advocates, and Southwest Energy Efficiency Project. In addition, Metro Water Recovery, which provides wastewater treatment in metropolitan Denver, filed comments.

30. We reviewed the comments and appreciate the participants' efforts to respond to our questions. The responses were helpful in crafting the proposed rules set forth in Attachments A and B to this Decision.

b. Additional Solicited Comments

31. In addition to the questions posed above, the Commission stated that it planned to continue to engage with the utilities and interested stakeholders even after the Commission issues the initial NOPR in this rulemaking Proceeding. The Commission explained that the October 1, 2021 statutory deadline for opening this rulemaking left insufficient time for the Commission to develop a comprehensive NOPR that integrates all of the statutory requirements adopted in the 2021 Colorado legislative session along with new rules governing gas utility planning. The Commission posed additional questions for gas and electric utilities and interested stakeholders, which are due in Proceeding No. 21M-0395G, on November 19, 2021. *See* Decision No. C21-0516 at ¶ 25. The Commission also requested that Colorado investor-owned gas utilities, by the same November 19, 2021 deadline, submit certain information regarding their projections for investment, rates, and greenhouse gas emissions. *See* Decision No. C21-0516 at ¶ 27.

C. Discussion

32. We adopted this NOPR at our weekly business meeting on September 22, 2021, in order to comply with the October 1, 2021 statutory deadline in SB 21-264 for the Commission to undertake a rulemaking proceeding to update the "demand-side management rules consistent

with the clean heat targets" established by the new statute. § 40-3.2-108(5)(a), C.R.S. Consistent with that directive, the scope of the rules attached to this Decision opening the rulemaking includes proposed new rules to implement CHPs as well as proposed modifications to the current Gas DSM Rules.[4]

33. The proposed rules attached to this Decision, also include new provisions governing gas planning. We attach an initial version of these new rules for gas planning to this Decision because they are intended to work in conjunction with the new rules for CHPs during the coming decades when the gas utilities transition their businesses and the services they provide to their customers to achieve the substantial reductions in statewide greenhouse gas emissions required by § 25-7-102(2)(g), C.R.S.

34. Notwithstanding our aim to solicit comments on the integration of gas planning with clean heat planning by this Decision, we hold to our intention to develop and issue a supplemental NOPR within this rulemaking in response to the additional comment and information being collected in Proceeding No. 21M-0395G. As explained above, our decision opening that proceeding set forth several questions for comment regarding short-term and long-term gas planning, and we required the utilities to submit information on their safety and integrity investments, rates and costs over the next 15 years, greenhouse gas emissions data, and additional data that the utility may have that generally supports gas planning. Those additional comments and informational filings are due on November 19, 2021, and will be used to craft one or more supplemental NOPR(s) in addition to comments submitted by the participants in this rulemaking.

[4] The Commission has not previously promulgated electric DSM rules.

35. We will conduct the first public comment hearing in this matter on February 17 and 18, 2022. In preparation for that hearing, we set a deadline for written comments on the rules attached to this NOPR to be filed no later than January 25, 2022. Written comments responsive to those initial comments are requested to be filed no later than February 8, 2022. The purpose of these deadlines is to ensure that comments and responses may be considered at the public comment hearing. Other comments may be filed in this Proceeding at any time.

36. We agree with the statement echoed in many of the comments filed on September 10, 2021, in Proceeding No. 21M-0395G that this rulemaking will be comprehensive and at the forefront of the evolution of the gas utility industry. We also must address the specific procedural requirements for this rulemaking set forth in SB 21-264. The Commission must convene at least four workshops or public meetings to solicit input on the contents and evaluation of the utilities' CHPs, two of which must be located in disproportionately impacted communities served by the utility that are required to submit a CHP. § 40-3.2-108(5)(a), C.R.S.

37. Because the rules to be promulgated in this rulemaking proceeding raise many questions, and because those rules must be developed according to specific statutory requirements no later than December 1, 2022 (§ 40-3.2-108(5)(b), C.R.S.), we will address additional procedures for this undertaking by a separate decision. We intend to discuss the need for workshops on topics that may be held before the public comment hearing scheduled for February 17 and 18, 2022, as well as additional workshops and public comment hearings that will follow that hearing, consistent with the release of the supplemental NOPR. We also will invite comments from the rulemaking participants on topics for additional workshops and other procedures. We further intend to solicit feedback specific to the statutory directive that

we conduct workshops or public comment hearings in the disproportionately impacted communities served by the utilities that are required to submit CHPs.

38. By this Decision, the Commission welcomes comments on the proposed rules as presented in Section D and Attachments A and B.

39. Where rules are described as "current," they refer to the currently effective rules prior to proposed amendments. "Proposed" rules refer to proposed changes, including new or reordered paragraphs, or revisions to language.

D. Proposed Amendments

1. Basis, Purpose, and Statutory Authority

40. The proposed revisions to the Basis, Purpose, and Statutory Authority section of the Gas Rules shift and broaden the focus of the rules to include not only regulation over jurisdictional gas utilities and their services but also their actions to reduce greenhouse gas emissions from the use of gas by their customers and from leaks in their facilities. We further add to these provisions the statement that the rules govern utility actions for the purposes of maintaining just and reasonable rates, ensuring system reliability and resiliency, and protecting disproportionately impacted communities, among others. The proposed revisions also expand the scope of areas addressed in the Gas Rules to include DSM programs and the reduction of greenhouse gas emissions from the distribution and end-use consumption of natural gas. Finally, the proposed revisions also add to the identified statutory authority for the rules to include new §§ 40-3.2-103, 40-3.2-106, 40-3.2-107, and 40-3.2-108, C.R.S., which were revised or added by HB 21-1238 and SB 21-264.

2. General Provisions

a. Rule 4001. Definitions.

41. Current Rule 4001 provides definitions to apply throughout Part 4 of the Gas Rules. We propose to add several new defined terms that arise from the new statutory requirements. We further move certain existing definitions from sections within the Gas Rules to Rule 4001 because they are used more broadly in accordance with the rule changes proposed in this NOPR.

42. Proposed paragraph (d) adds a definition for the term "Air Quality Control Commission" or "AQCC." The proposed definition refers to the division of the CDPHE created by § 25-1-102(2)(a), C.R.S., to oversee Colorado's air quality program.

43. Proposed paragraph (g) adds a definition for the term "biomethane," based on the new statutory definition in § 40-3.2-108(2)(a), C.R.S., added by SB 21-264.

44. Proposed paragraph (o) adds a definition for the term "discount rate," consistent with the direction in § 40-3.2-107(2)(c), C.R.S., added by HB 21-1238, regarding discount rates for future cost streams. Specifically, this section (2)(c) instructs that, notwithstanding the discount rate used for certain presentations of the cost of greenhouse gas emissions in net present value calculations, the Commission shall discount other future cost streams into the net present value analysis of any resource portfolio in the gas DSM program planning process using a discount rate that the Commission deems relevant to the parties responsible for financing or paying these future costs. The statute further directs, when ratepayers are covering costs without investment from gas utilities, such as environmental costs or pass-through fuel costs, the Commission shall give consideration to discounting those costs with a stable long-term inflation rate that, in the Commission's judgment, accurately represents

the net present value of future cash flows experienced by ratepayers. Notably, this addition to the Gas Rules recognizes that the default discount rate to be used by the gas utilities in calculating certain net present values is no longer each utility's weighted average cost of capital. We expect that the Commission will determine the appropriate discount rate or discount rates to be applied for net present value calculations as they pertain to DSM plans, CHPs, and other utility proceedings in those related proceedings.

45. Section 40-3.2-108(2)(f), C.R.S., defines the term "gas" to mean "geological gas, hydrogen, and recovered methane." Section 40-3.2-108(2)(h), C.R.S., further defines the term "geological gas" to mean "methane and other hydrocarbons that occur underground without human intervention and are used as fuel." Accordingly, we propose to modify the definition of "gas" in current paragraph (o) to match the statutory definition of "gas" in SB 21-264 and to add the qualifier that such gas is "produced, transmitted, distributed, or furnished by any utility" as in the current definition to clarify the applicability of the rule to regulated utilities. This change is shown in proposed paragraph (r). We also propose to add a new definition of "natural gas" or "geological gas" in proposed paragraph (dd) based on the new statutory definitions. We recognize that the term "gas" is ubiquitous in the Gas Rules and will address its proper usage throughout 4 CCR 723-4 during the course of this rulemaking proceeding. We invite comments highlighting rule modifications required by the new statutory definitions and the implementation of those terms as proposed here.

46. Proposed paragraph (s) adds a definition for the term "green hydrogen," consistent with §§ 40-3.2-108(2)(c)(III), 40-3.2-108(2)(j), 40-3.2-108(4)(f), C.R.S., added by SB 21-264, regarding hydrogen that qualifies as a clean heat resource.

47. Proposed paragraph (z) adds a definition for the term "mandatory relocation," which refers to projects to relocate gas infrastructure as required by state, county, or local governmental bodies. This definition is based on the proposed rules attached to the Joint Petition.

48. Proposed paragraph (jj) adds a definition for the term "pyrolysis," borrowing from the statutory definition in § 40-2-124(1)(a)(V), C.R.S., that lists the eligible energy resources that can be used to meet the state's renewable energy standard requirements.

49. Proposed paragraph (kk) adds a definition for the term "recovered methane," based on the new statutory definition in § 40-3.2-108(2)(n), C.R.S., added by SB 21-264.

50. Proposed paragraph (ll) adds a definition for the term "recovered methane credit," derived from the new statutory definition in § 40-3.2-108(2)(o), C.R.S., added by SB 21-264. The proposed definition also relies on § 40-3.2-108(3)(e), C.R.S., requiring any recovered methane to be used towards meeting clean heat targets to be represented by a recovered methane credit issued in accordance with an AQCC-approved protocol, a provision also reflected elsewhere in the modified Gas Rules such as in subparagraph 4730(b)(II)(A).

51. In proposed paragraph (nn), we propose to provide a new single definition for a "sales customer" or a "full service customer" so that a single definition can apply throughout the Gas Rules. The proposed definition for these customers is: a customer who receives sales service from a utility and is not served under a utility's gas transportation service rate schedules. The term "full service customer" is used in the DSM and CHP Rules.

b. Rule 4002. Applications.

52. Current paragraph (a) of this rule sets forth the matters for which a person can seek Commission action through the filing of an appropriate application. We propose to add

additional subsections to this list to include applications for: approval of a utility's gas plan, approval of a utility's CHP, approval of a utility's DSM plan, and determinations on a utility's DSM Strategic Issues application.

c. Rule 4002. Records.

53. Current paragraph (a) of this rule addresses the maintenance of records. We propose to add additional subsections to this list to include records associated with gas plans and CHPs.

3. Operating Authority

a. Rule 4102. Certificate of Public Convenience and Necessity for Facilities.

54. Current paragraph (a) of this rule requires a utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., to file an appropriate application with the Commission. We propose to revise this paragraph (a) to specify that a utility shall apply for Commission approval of construction and operation of a facility or an extension of a facility identified as a proposed project, if the project costs exceed $15 million for utilities with 500,000 customers or more or $10 million for utilities with fewer than 500,000 customers. The proposed rule specifies that the project cost threshold is in 2020 dollars and shall be adjusted annually on January 1 of each year for inflation according to the consumer price index. The proposed rule specifies that Commission approval for such projects is required even where the project would otherwise be considered in the utility's ordinary course of business.

55. The new provisions in paragraph (a) are based on the rules proposed in the Joint Petition. However, the Joint Petition limited the blanket requirement for Certificates of Public

Convenience and Necessity (CPCNs) above the dollar thresholds to what is defined in the Joint Petition's rules as "Reliability Projects" and provided for the exclusion of projects that were recovered through a system safety and integrity rider. Here, we propose instead to apply the dollar thresholds proposed in the Joint Petition for "Reliability Projects" to all types of projects given the expense of the projects and the regulatory review necessary for such projects in light of Colorado's greenhouse gas emission reduction goals and statutory requirements.

56. The new provisions in paragraph (a) link to the new Gas Planning Rules described below. Unlike the rules attached to the Joint Petition, there is no exclusion from CPCN requirements for system safety and integrity investments, including those whose costs are recovered as part of a Commission approved rider.

57. Current paragraph (b) of this rule sets forth the minimum requirements for an application filed with the Commission for a CPCN. We propose to revise subparagraph (b)(VII) to require the utility to provide, either in the application or in an attachment, the assessment of the proposed facilities in the most recent gas plan filed by the utility pursuant to the Gas Planning Rules, including information on alternatives studies, costs for those alternatives, and criteria used to rank or eliminate alternatives.

58. We further propose a new paragraph (c) in this rule specifying that a CPCN is not required for mandatory relocations, consistent with the proposed rules attached to the Joint Petition.

59. However, we do not allow for a blanket exemption for unanticipated time-sensitive projects needed for the purpose of ensuring the safe and reliable service to the utility's customers. For those projects, the utility may file for a waiver from the requirements of the CPCN requirements in Rule 4102 for good cause shown, in accordance with proposed

new paragraph (d). Notwithstanding this proposal, we seek comments addressing whether there are specific clarifications or a uniform treatment of time-sensitive projects as an alternative to a blanket exclusion.

4. Facilities

a. Rule 4210. Line Extensions.

60. Current paragraph (a) of this rule requires utilities to have tariffs setting out their line extension policies, procedures, and conditions. Current paragraph (b) specifies the minimum provisions a utility must include for gas main extensions and service lateral extensions from its distribution system.

61. We propose to add a new paragraph (c) that requires that the utility base its line extension policies on the principle that the full incremental cost associated with new development and growth shall be borne generally by the customers that cause those incremental costs.

62. We likewise propose to add a new paragraph (d) to require annual updates to the standardized costs in calculating components of the utility's line extension policy based on actual costs for line extensions over time. We also seek comments on whether the Commission should ensure that: (1) utility line extension policies are as consistent as possible, at least in methodology among the gas utilities; and (2) these policies provide no more rate-based contribution than necessary given the potential impacts from the state's greenhouse gas emissions reduction requirements.

63. We further propose to add a new paragraph (e) that requires that a utility's line extension policies, procedures, and conditions to align with the statewide greenhouse gas emissions reduction goals established in § 25-7-102(2)(g), C.R.S. Consistent with the

prohibition in § 40-3.2-103(3.5)(b), C.R.S., added by HB 21-1238, the proposed rule specifies the Commission will not ban the installation of gas service lines to any new structure.

5. Greenhouse Gas Emissions

64. We propose to add a new section to the rules that implement the pollution cost requirements in § 40-3.2-106, C.R.S., as revised by HB 21-1238, as such requirements apply to utility DSM and CHP requirements.

a. Rule 4525. Overview and Purpose.

65. As noted above, the purpose of this new section is to implement § 40-3.2-106, C.R.S., for the purpose of implementing the provisions for DSM and CHPs pursuant to these rules.

b. Rule 4526. Definitions.

66. We propose to specify a definition for the term "federal technical support document" as used in this new section. The proposed definition refers to the 2016 technical support document of the Federal Interagency Working Group on Social Cost of Greenhouse Gases.

c. Rule 4527. Measurement and Accounting.

67. We propose in this rule certain requirements for how utilities shall measure and account for greenhouse gas emissions or in formulating their required projections.

68. We propose to add a new paragraph (a) that specifies that the greenhouse gases include carbon dioxide and methane in accordance with changes to § 40-1-102, C.R.S., from HB 21-1238 and that both gases shall be measured in terms of the carbon dioxide equivalent pursuant to §§ 40-3.2-108(2)(i) and 40-3.2-108(3)(d), C.R.S., from SB 21-264.

69. We likewise propose to add a new paragraph (b) to require, at a minimum, that the utility project greenhouse gas emissions to include: methane leaked from the transportation and delivery of gas from the gas distribution and service pipelines from the city gate to its customer's end use; carbon dioxide emissions resulting from the combustion of gas by residential, commercial, and industrial customers not otherwise subject to federal greenhouse gas emissions reporting and excluding all transport customers; and emissions of methane resulting from leakage from delivery of gas to other local distribution companies. These provisions derive from § 40-3.2-108(3)(c)(I), C.R.S., from SB 21-264.

d. Rule 4528. Social Cost of Carbon and Social Cost of Methane.

70. We set forth in this proposed rule, the statutory obligations on the Commission when establishing the cost of carbon dioxide and methane emissions, based on the requirements in § 40-3.2-106(4), C.R.S. The aim of the proposed rules is to structure the provisions for the social cost of carbon and the social cost of methane in a parallel manner.

71. Proposed paragraph (a) requires the Commission-determined social cost of carbon to be based on the most recent social cost of carbon dioxide developed by the federal government. Proposed subparagraph (a)(I) sets the minimum value for the social cost of carbon and subparagraph (a)(II) specifies the escalation rate to be used to calculate the social cost of carbon for each year in the future. Proposed paragraph (b) sets forth the discount rate for certain presentation of net present values for the social cost of carbon.

72. Likewise, proposed paragraph (c) requires the Commission-determined social cost of methane to be based on the most recent social cost of carbon methane developed by the federal government. Proposed subparagraph (c)(I) sets the minimum value for the social cost of methane and subparagraph (c)(II) specifies the escalation rate to be used to calculate the

social cost of methane for each year in the future. Proposed paragraph (d) sets forth the discount rate for certain presentation of net present values for the social cost of methane.

6. Gas Planning

73. The enactment of SB 21-264 and the development of rules governing the development, presentation, and approval of CHPs are essential to the statewide greenhouse gas emissions reduction goals established in § 25-7-102(2)(g), C.R.S. CHP proceedings will serve as a venue for the Commission to evaluate greenhouse gas emission reductions on the gas utility's systems and to compare portfolios of clean heat resources to achieve the state's required emission reductions for this sector, including both the emissions from the utility's facilities as well as from the emissions from the end-use combustion of gas by the utility's customers.

74. The CHP approach to reducing greenhouse gas emissions will not address all of the issues that the gas utilities and its customers will face through the transitions required to meet Colorado's goals. We therefore propose to introduce new rules that address gas utility planning in this rulemaking. The development of Gas Planning Rules concurrently with the promulgation of the rules governing CHPs will enable the utilities, their customers, and the Commission to examine the future use of the utility pipeline system and economics of the retail service they provide over the long-term, culminating in the 2050 statewide reductions in emissions as set forth in § 25-7-102(2)(g), C.R.S.

75. We also propose new Gas Planning Rules to improve the visibility into a gas utility's future projects and expenditures. Such new rules are necessary to understand the scale of investment planned on the utility systems and where new facilities are being considered to meet various needs within specific geographic areas. Recent utility rate cases and proceedings addressing the recovery of system safety and integrity investments through rate riders have

raised many issues surrounding the transparency of planning and cumulative investment and expenditures. The rules are intended to advance necessary improvements in planning to better protect the public interest.

a. Rule 4550. Overview and Purpose

76. Proposed Rule 4550 states that the purpose of this new section is to foster the examination of the investment and expenditures of jurisdictional utilities that are subject to the Commission's regulatory authority over rates. More specifically, the purpose of these rules is to establish a process to determine the need for additional investment and spending consistent with maintaining just and reasonable rates, ensuring system reliability and resiliency, protecting income-qualified and disproportionately impacted communities, and meeting the statewide greenhouse gas emissions reduction goals established in § 25-7-102(2)(g), C.R.S., and the associated clean heat targets in Rule 4728. These rules further implement planning and reporting requirements to help minimize costs to utilities and their customers over the long-term. These rules further establish guidelines to determine when a gas utility should be required to file an application for a CPCN in accordance with Rule 4102.

b. Rule 4551. Definitions.

77. Proposed paragraph (a) provides a definition for the term "planned project." This proposed definition is based on the definition for the same term in the rules attached to the Joint Petition, however, we remove the exclusion of operating and maintenance expenses. We further propose to set a uniform cost threshold of $2 million to define planned projects for all utilities, unlike the three separate thresholds for utilities depending on the number of customers served by the utility, as proposed in the rules attached to the Joint Petition (*i.e.*, $1 million for the smallest utilities, $3 million for the largest utilities, and $2 million for the other utilities).

78. Proposed paragraph (b) provides a definition for the term “short-term plan period.” The short-term plan period is five years, consistent with the “five rolling calendar year” contemplated for the rules attached to the Joint Petition.

79. Proposed paragraph (c) provides a definition for the term “long-term plan period.” The long-term plan period ends in 2050, consistent with the state’s greenhouse gas emissions reduction goals pursuant to § 25-7-102(2)(g), C.R.S.

c. Rule 4552. Filing Form and Schedule.

80. We propose in this rule, form and timing requirements for utilities to file their gas plans.

81. Proposed paragraph (a) requires that a utility file its gas plan by March 31, every two years. The need to develop and then refine gas plans requires frequent filings during the initial implementation of these new rules and aligns with the frequent reporting sought in the rules attached to the Joint Petition.

82. Proposed paragraph (b) specifies that the utility’s first gas plan shall be filed for informational purposes no later than March 31, 2023. The proposed rule explains how the Commission will use the information filing to refine future plan filings through a process modeled on the Commission’s review of the transmission plans submitted by Colorado’s electric utilities. The utility’s report filing will commence a proceeding in which the Commission will solicit written comments and may schedule workshops and a public comment hearing. The Commission may request additional supporting information from the utility, either on its own motion or at the request of others. The Commission will issue a written decision regarding compliance with these rules and provide further guidance to the utility to be used as it prepares the next biennial filing.

83. Proposed paragraph (c) requires that, beginning in some future year, the utility's gas plan shall be filed as an application, with the attendant processes and procedures for adjudicating an application. We solicit comments on whether, for example, the utility's second gas plan should also be filed for informational purposes or instead should initiate the same adjudicated application process contemplated for all future gas plans. Consistent with the timeframe for the filing of CHPs, however, we are interested in completing a full adjudication of a utility's gas plan prior to the filing of CHPs that show how the utility will meet its clean heat targets for 2035. This objective likely requires the gas plans be filed no later than March 31, 2027, to be submitted for approval as applications.

d. Rule 4553. Contents of a Gas Plan.

(1) General.

84. Proposed paragraph (a) sets forth the general contents of a gas plan.

85. In proposed subparagraph (I), we require that the utility explain how it developed its gas plan, consistent with the proposed provisions in the rules attached to the Joint Petition that the utility describe its planning and infrastructure modeling process, including the assumptions and variables that are inputs to that process.

86. In proposed subparagraph (II), we likewise require a description of the utility's budgeting planning process, again consistent with the proposed provisions in the rules attached to the Joint Petition.

87. Proposed subparagraph (III) requires a forecasted capital spend listed by project category, consistent with the proposed provisions in the rules attached to the Joint Petition for "Transmission and Distribution." As described below, the project categories contemplated by

these proposed rules include "new business projects," "capacity expansion projects," "system safety and integrity projects," and "all other capital spend not categorized."

88. Proposed subparagraph (IV) requires the utility to state annual operating and maintenance expenses from its annual reports, consistent with the proposed provisions in the rules attached to the Joint Petition.

89. Proposed subparagraph (V) requires the utility to provide a copy of the utility's prior year Department of Transportation 7100 Report, consistent with the proposed provisions in the rules attached to the Joint Petition.

90. Proposed subparagraph (VI) requires the utility to summarize its stakeholder outreach regarding the development of the gas plan. We introduce this requirement, because stakeholder participation is a feature of other planning efforts governed by the Commission and because we seek to ensure outreach to disproportionately impacted communities.

91. Finally, proposed subparagraph (VII) requires the utility to reference the gas plans in which proposed projects are reviewed in related CPCN application filings. This provision is intended to foster the implementation of the later provisions in proposed Rule 4555 regarding the Commission's approval of a utility's gas plan and its impacts on related requests for CPCNs.

(2) Forecasts.

92. Proposed paragraph (b) sets forth the requirements to develop and present forecasts. These provisions expand on the proposed introduction of "a forecast of gas to be delivered to customers and customer counts, by class" in the rules attached to the Joint Petition and are based on the forecasts the state's jurisdictional electric utilities file with their plans submitted for Commission review.

93. The proposed subparagraphs are based on the forecasting required of the state's electric utilities pursuant to the Commission's Electric Resource Planning Rules at 4 CCR 723-3-3606. Subparagraph (I) requires forecasts for sales, customer counts, and capacity (design or peak day) for each year for the short-term plan period (*i.e.*, next five years) and long-term plan period (*i.e.*, through 2050). Subparagraph (II) requires the utility to fully describe the underpinnings of the forecasts. Subparagraph (III) requires forecast scenarios. The rule identifies as factors influencing the forecasts to include: clean heat resources, customer response to changing rates and bill impacts, changes in building codes and local building regulations affecting the use of gas for end-use consumption, the beneficial electrification of gas end-uses, and extreme weather events. Finally, subparagraph (IV) addresses the need for forecasts to become increasingly localized in order to evaluate alternatives to the planned projects set forth in the utility's gas plans, including clean heat resources and non-pipeline alternatives in accordance with § 40-3.2-1082(3)(f), C.R.S.

(3) Gas Commodity.

94. Proposed paragraph (c) allows for certain procurements of gas commodities for full-service customer to be included in the utility gas plans.

95. Subparagraph (I) acknowledges that the procurement of geologic gas as newly defined by statute will be addressed primarily through the operation of the Commission's Gas Cost Adjustment Rules in 4 CCR 723-4-4600, *et. seq.*[5]

96. Subparagraph (II) similarly acknowledges that the acquisition of biomethane and green hydrogen will be addressed primarily though the operation of the new CHP Rules.

[5] The Commission is examining potential changes to these rules in an ongoing rulemaking in Proceeding No. 21R-0314G.

97. Subparagraph (III) allows utilities to propose in a gas plan, the acquisition of environmentally responsible or responsibly sourced gas for resale to full-service customers. Such gas commodity would come from suppliers and sources dedicated to reduced methane emissions, improved energy and water efficiency, and best practices in water management and conservation.

98. We also seek comment on whether the Commission should set a minimum purchase standard of environmentally responsible or responsibly sourced gas, which would sit above and beyond the requirements from SB 21-264, since environmentally responsible or responsibly sourced gas are not eligible clean heat resources. We also seek suggestions on any standards that should be considered for environmentally responsible or responsibly sourced gas, both in terms of certification and in terms of the percentage of gas commodity acquired by the utility.

(4) New Business and Capacity Expansion Projects.

99. Proposed paragraph (d) sets forth the details the utility must provide for planned projects in the new business and capacity expansion categories. (Subparagraph (e)(II) requires the same details for system safety and integrity projects as well.) These provisions derive largely from the rules attached to the Joint Petition.

100. Subparagraph (I) defines the planned projects that fit in the new business category, consistent with the definition for such projects in the rules attached to the Joint Petition.

101. Subparagraph (II) defines the planned projects that fit in the capacity expansion category, consistent with the definition for "reliability projects" in the rules attached to the Joint

Petition. These details are largely taken from the requirements set forth for projects subject to the reporting in the rules attached to the Joint Petition

102. Subparagraph (III) lists the specific information that the utility must provide for each planned project. These requirements also stem from the requirements proposed in the rules attached to the Joint Petition. The proposed rules require a showing that any individual customer or class of customers responsible for the requirement investment will pay for the associated incremental costs. The proposed rules further support the increasingly localized examination of the need for the project relative to potential alternatives and the associated impacts on sales, rates, and bills for customers served by the proposed project.

103. Subparagraph (IV) excludes from the gas planning requirements planned projects that constitute "programs of work." This proposed exclusion is consistent with the same exclusion from the rules attached to the Joint Petition. Consistent with the rules attached to the Joint Petition, "programs of work" must be addressed in the annual gas plan reports required in proposed Rule 4554.

104. Subparagraph (V) requires the utility to address the status of planned projects addressed in previous gas plans, including changes, additions, or deletion in the current plan as compared with the prior plans.

105. Finally, subparagraph (VI) acknowledges that the Commission may require a utility to file an application for a CPCN in accordance with Rule 4102 for a planned project detailed in the utility's gas plan. This rule deviates from the approach proposed in the rules attached to the Joint Petition where the utility would state whether it plans to submit the project for CPCN consideration or otherwise request a Commission determination that a CPCN application is not required.

(5) System Safety and Integrity Projects.

106. Proposed paragraph (e) sets forth the details the utility must provide for planned projects in the system safety and integrity category.

107. Subparagraph (I) provides examples of planned projects that fit within the category of system safety and integrity projects.

108. Subparagraph (II) requires the same details for system safety and integrity projects as for new business projects and capacity expansion projects as explained above.

109. Subparagraph (III) addresses the statutory requirements in § 40-3.2-108(3)(f), C.R.S., that leak reductions caused by repairs to the utility's system are cost effective. The intent of this provision is to allow for gas utilities to recover the costs of necessary system safety and integrity projects pursuant to an approved gas plan even when leaks addressed by such projects would not otherwise be determined cost-effective in competition with other clean heat resources available for the purpose of achieving reductions in greenhouse gas emissions. (Complementary rules are included in proposed Rule 4730 as described below.)

110. Subparagraph (IV) mirrors the same provision for new business projects and capacity expansion projects where a utility shall address the status of planned projects in the system safety and integrity category that were addressed in previous gas plans, including changes, additions, or deletion in the current plan as compared with the prior plans.

(6) Long-term Planning and Non-pipeline Alternatives.

111. Proposed paragraph (f) addresses the components of a gas plan that will improve the analysis and review of the utility's investments and expenditures beyond the short-term plan period in efforts to minimize costs to customers while the utility takes actions to meet the statewide greenhouse gas emissions reduction goals in § 25-7-102(2)(g), C.R.S.

112. Section 40-3.2-108(3)(f), C.R.S., as introduced by SB 21-264, permits the Commission to require the utilities to evaluate "non-pipeline alternatives." Consistent with the discussion above regarding forecasts that are increasingly geographically-specific, proposed subparagraph (I) requires the utility to describe its progress in the ability to make projections beyond the short-term plan periods and to conduct analyses on a geographically-specific basis, in addition to its progress in evaluating non-pipeline alternatives. We seek comment on whether forecasts for investments and expenses can be reported by the utility down to the applicable upstream regulator station or some other geographically-defined area to provide an increasingly localized approach to both short-term and long-term planning.

113. Subparagraph (II) requires projections of rates and bill impacts to take into account depreciation schedules, changes in sales and customer counts, and gas commodity prices over the long-term plan period.

114. Subparagraph (III) echoes in the Gas Planning Rules the need for the utility to balance various goals as also stated in the modified Basis, Purpose, and Statutory Authority that introduces the Commission's Gas Rules.

e. Rule 4554. Annual Gas Plan Reporting.

115. This rule addresses the annual reporting that completes the gas planning framework proposed in this rulemaking.

116. Proposed paragraph (a) requires that the utility file an annual gas plan report by September 1 of each year. The utility is required to address changes, additions, or deletions as compared to the gas plan most recently reviewed by the Commission.

117. Proposed paragraph (b) requires that the utility also describe the status of each planned project consistent with the details of each planned project as set forth in the utility's

gas plan, as summarized in subparagraph 4553(d)(III). The utility must explain deviations from the gas plan in terms of project costs, scope of work, and the implementation timeline.

118. Proposed paragraph (c) requires the annual reports to describe the "programs of work" completed during the previous year, as such projects are not required components of the biennial gas plan filings.

f. Rule 4555. Approval of Gas Plan.

119. The rules attached to the Joint Petition specified that the planning report contemplated for short-term gas infrastructure planning was for "informational purposes only." The proposed Gas Planning Rules set out in this NOPR, however, contemplate the filing of applications for Commission approval of the gas plan. This rule explains the effect of such a decision in rate cases and CPCN proceedings and is modeled on the rules that govern Commission decisions on electric utility resource plans.

120. Proposed paragraph (a) states that the Commission will issue a written decision approving, disapproving, or ordering modifications to the utility's gas plan when such plan is filed as an application proceeding.

121. Proposed paragraph (b) requires the utility to submit an amended plan and establishes related procedures.

122. Proposed paragraph (c) grants a presumption that the utility's actions consistent with the Commission decisions approving its gas plan, are presumed prudent in rate cases, per subparagraph 4555(c)(I), and in CPCN proceedings, per subparagraph 4555(c)(II).

7. Clean Heat Plans

123. We propose this new section of the Gas Rules to implement SB 21-264. The rules proposed for this new section are closely based on the statutory language in § 40-3.2-108, C.R.S., as enacted by SB 21-264.

a. Rule 4725. Overview and Purpose.

124. As noted above, the purpose of this section is to implement § 40-3.2-108, C.R.S., for utilities required by statute to be rate-regulated by the Commission. Consistent with statutory requirements, the purpose of these CHP Rules is to reduce greenhouse gas emissions from the distribution and end-use consumption of natural gas in accordance with clean heat targets.

b. Rule 4726. Applicability.

125. Proposed paragraph (a) clarifies that the CHP Rules apply to all jurisdictional gas utilities. However, proposed paragraphs (b) and (c) further clarify that the jurisdictional gas utilities subject to the CHP Rules serve retail customers. Proposed paragraph (c) defines the "small gas distribution utility" that may file CHPs to meet clean heat targets for 2025 and 2030 in accordance with proposed Rule 4734, as described below. These proposed paragraphs implement §§ 40-3.2-108(2)(g) and (q), C.R.S.

126. Proposed paragraph (d) clarifies that these rules do not apply to municipally owned gas utilities. Section 40-3.2-108(2)(q), C.R.S., excludes a municipal gas utility from taking advantage of the provisions for a "small gas distribution utility" defined elsewhere in SB 21-264 and instead requires the submission of CHPs to the AQCC in accordance with § 40-3.2-108(2)(g), C.R.S., and with provisions in § 25-7-105, C.R.S.

c. Rule 4727. Definitions.

127. Proposed paragraph (a) is the sole definition specific to the CHP Rules. Consistent with §§ 40-3.2-108(4)(b) and (h), C.R.S., a "plan period" is, at a minimum, five years after the date of the utility's filing of its CHP, with the exception of the utility's first plan that addresses emission reductions relative to goals for 2025.

d. Rule 4728. Clean Heat Targets.

128. Proposed paragraph (a) requires all clean heat targets to align with the statewide goals for greenhouse gas emissions reductions set forth in § 25-7-102(2)(g), C.R.S.

129. Proposed paragraph (b) implements the requirements in §§ 40-3.2-108(3)(b)(c)(II) and 40-3.2-108(11), C.R.S., that, in general, baseline emissions, system-wide emissions, and reductions in emissions shall be based on reported amounts to the federal Environmental Protection Agency, in addition to best methods for calculating emissions that may fall outside of the federal reporting requirements. The proposed rule also specifically requires the ACQQ to use, in its consultations with the Commission, the AR-4 100-year global warming potential value determined by the federal Environmental Protection Agency.

130. Proposed paragraph (c) addresses the 2015 baseline against which all clean heat targets are based in § 40-3.2-108, C.R.S. Subparagraph (I) defines the baseline as corresponding to calendar year 2015. Subparagraph (II) implements § 40-3.2-108(3)(c), C.R.S., with respect to the baseline that must include: (1) methane leaked from the utility's pipeline system up through its customers end use; (2) carbon dioxide emissions from the combustion of gas by the customer (with certain exclusions); and (3) methane leaked from the delivery of gas on the utility's pipeline system to other utilities. Consistent with § 40-3.2-108(3)(d), C.R.S., proposed subparagraph (III) requires the baseline to have separate calculations of carbon dioxide emissions

and methane emissions. The customer excluded from the baseline pursuant to subparagraph (II) must be identified by the utility under proposed subparagraph (IV).

131. In relation to paragraph (c), we seek information on the following:

- With respect to methane leaked behind the customers' meter, what is the best available information regarding the amount of such leaks?
- With respect to emissions associated from the combustion of gas by the utility's customer, what methods should be used to ensure accurate and consistent projections and measurements?
- With respect to the 2015 baseline and projected or measured emission reductions, will the use of the federal Environmental Protection Agency's Subparts W (for methane) and NN (for carbon dioxide) provide the Commission with the most accurate, reliable, and complete information about greenhouse gas emissions from the city gate to customer end uses?
- With respect to the methane leaked from the delivery of gas on the utility's pipeline system to other utilities, is it necessary for the Commission to define the specific locations and components to be included in the calculation of the baseline emission and emission reductions to ensure consistency across the utilities?
- Are there areas of concern or areas in which greenhouse gas emissions may go uncounted?

132. Proposed paragraph (d) sets forth the clean heat targets for 2025 and 2030 as well as the requirements for clean heat targets for 2035 and beyond.

133. Proposed subparagraph (I) sets for the clean heat targets for 2025 and 2030, clarifying that the allowable contribution made to recovered methane is one fourth of the required reduction in greenhouse gas emissions for 2025 and five-twenty seconds of the required reduction in greenhouse gas emissions for 2030. Proposed subparagraph (I) implements §§ 40-3.2-108(3)(b)(II) and 40-3.2-108(4)(d), C.R.S.

134. Proposed subparagraph (II) addresses the establishing of clean heat targets for 2035 and implements § 40-3.2-108(10), C.R.S. The Commission must establish the 2035 target

no later than December 1, 2024, and the targets must align with the statewide greenhouse gas emissions reduction goals in § 25-7-102(2)(g), C.R.S.

135. Proposed subparagraph (III) addresses the establishing of clean heat targets for 2040, 2045, and 2050 and implements § 40-3.2-108(11), C.R.S. These targets also must align with the statewide greenhouse gas emissions reduction goals in § 25-7-102(2)(g), C.R.S.

136. Proposed paragraph (e) addresses the maximum amount of each established clean heat target after 2030 that may be satisfied with recovered methane. The proposed paragraph implements § 40-3.2-108(4)(d)(II)(B), C.R.S.

e. Rule 4729. Filing Form and Schedule.

137. Proposed paragraph (a) requires the utility's CHP to be filed as an application, with the attendant processes and procedures for adjudicating an application.

138. Proposed paragraph (b) implements § 40-3.2-108(4)(a), C.R.S., requiring Public Service Company of Colorado to file its first CHP no later than August 1, 2023, and further implements the plan period requirements explained above by requiring the second CHP to be filed no later than August 1, 2024. The proposed rule allows for a combined application that includes both of the first two heat plans no later than August 1, 2023. The proposed rule further implements § 40-3.2-108(4)(b), C.R.S., that requires a CHP filing every four years.

139. Proposed paragraph (c) further implements § 40-3.2-108(4)(a), C.R.S., for the utilities other than Public Service Company of Colorado. These utilities must file their first CHPs no later than January 1, 2024, and further implements the plan period requirements explained above by requiring the second CHP to be filed no later than January 1, 2025. The proposed rule then implements § 40-3.2-108(4)(b), C.R.S., that requires a CHP filing every four years.

f. Rule 4730. Clean Heat Resources.

140. Proposed Rule 4730 defines the clean heat resources that may be included in a CHP.

141. Proposed paragraph (a) clarifies that a clean heat resource, the resource procured or implemented pursuant to a CHP, addresses the reduction in greenhouse gas emissions both from the utility's pipeline system and from the combustion of gas by the utility's retail customers. Proposed paragraph (a) thus implements § 40-3.2-108(3)(b)(I), C.R.S., along with proposed Rule 4731(a) described below.

142. Proposed paragraph (b) implements the statutory definition of clean heat resources in § 40-3.2-108(2)(c), C.R.S.

143. Subparagraph (I) includes DSM as a clean heat resource and includes the provisions in § 40-2-123(1)(b)(I), C.R.S., from HB 21-1238. Subparagraph (A) requires the Commission to collaborate with the AQCC to ensure emissions reductions achieved through gas DSM programs are appropriately accounted for in meeting statewide greenhouse reduction goals. Along those lines, we propose subparagraph (B) that ensures that the gas DSM that qualifies as a clean heat resource does not prolong a customers' reliance on gas for end use consumption. Subparagraph (C) likewise requires the carbon dioxide and methane reductions achieved by implementing gas DSM are consistent with the amounts used to apply the social cost of carbon and the social cost of methane in the determination of the cost-effectiveness of the DSM pursuant to the implementation of the Gas DSM Rules.

144. Subparagraph (II) includes recovered methane as a clean heat resource consistent with the definitions and limitations in § 40-3.2-108, C.R.S. Subparagraph (A) implements § 40-3.2-108(3)(e), C.R.S., such that all recovered methane that qualifies as a clean heat

resource must be represented by a recovered methane credit issued by an AQCC-approved protocol. Subparagraph (B) implements both § 40-3.2-108(2)(n), C.R.S., that requires recovered methane to be located in Colorado and the additional requirements set forth in § 40-3.2-108(3)(e), C.R.S.

145. Subparagraph (III) lists green hydrogen as defined in proposed paragraph 4001(r) that reduces greenhouse gas emissions in accordance with § 40-3.2-108(4)(f), C.R.S.

146. Subparagraph (IV) lists beneficial electrification as a clean heat resource in accordance with the statutory definition in § 40-3.2-108(2)(c), C.R.S. As for gas DSM, subparagraph (A) likewise requires the carbon dioxide and methane reductions achieved by implementing beneficial electrification are consistent with the amounts used to apply the social cost of carbon and the social cost of methane in the determination of the cost-effectiveness of beneficial electrification.

147. Subparagraph (V) lists the pyrolysis of tires as a clean heat resource in accordance with the statutory definition in § 40-3.2-108(2)(c), C.R.S.

148. Finally, subparagraph (VI) allows for other clean heat resources to be included in a CHP, if the Commission finds the resource to be cost effective in reducing greenhouse gas emissions, again in accordance with the statutory definition in § 40-3.2-108(2)(c), C.R.S.

149. Proposed paragraph (c) implements the provision in the statutory definition of clean heat resources in § 40-3.2-108(2)(c), C.R.S., that to qualify as a clean heat resource, any recovered methane credit must be retired in the year generated and may not be sold.

150. Proposed paragraph (d) implements the requirement in § 40-3.2-108(3)(f), C.R.S., that, to qualify as a clean heat resource, any repairs to the utility's system shall be determined to be cost-effective by the Commission. We interpret this provision as intended to prevent,

when determining the annual retail rate impact of a portfolio of clean heat resources presented in a CHP, the costs of system safety and integrity investments from crowding out other clean heat resources in relation to annual retail cost impact calculation. In other words, if the utility seeks to use integrity improvements as a clean heat resource, it must show in a CHP proceeding that the associated emission reductions are cost effective as a greenhouse gas mitigation measure when compared to other alternative clean heat resources.

151. Proposed paragraph (e) addresses the exclusion of transport customers in the calculation of emission reductions relative to the 2015 baseline such as the exclusions in §§ 40-3.2-108(3)(c)(I)(B) and 40-3.2-108(11), C.R.S. A change in service from sales service to transportation service shall not be considered a clean heat resource.

g. Rule 4731. Clean Heat Plan.

152. Proposed Rule 4731 sets forth the required components of a CHP and the standards that a CHP must meet in addition to those addressed in proposed Rule 4732.

153. Proposed paragraph (a) requires the utility to demonstrate that it will meet the applicable clean heat targets through the acquisition or implementation of clean heat resources in accordance with §§ 40-3.2-108(2)(b), 40-3.2-108(3)(a), and 40-3.2-108(4)(c)(I), C.R.S. The proposed rule further implements §§ 40-3.2-108(4)(c)(II)(A) and 40-3.2-108(4)(d)(I), C.R.S., that require the utility to use clean heat resources to the maximum extent practicable.

154. Proposed paragraph (b) implements the requirements for a CHP set forth in § 40-3.2-108(4)(c), C.R.S.

155. While subparagraphs (I) and (II) implement general statutory requirements in § 40-3.2-108(4)(c), C.R.S., subparagraph (III) addresses the specific portfolio combinations of clean heat resources that must be presented in the CHP in accordance with

§ 40-3.2-108(4)(c)(II), C.R.S. We add to the statutorily required portfolios the instruction that the utility must present its preferred portfolio of clean heat resources with the factors that the utility must consider in selecting its preferred portfolio.

156. Subparagraphs (IV) and (V) implement § 40-3.2-108(4)(c)(III), C.R.S., requiring details on the 2015 baseline and the quantified reductions in greenhouse gas emissions relative to that baseline. The presentation of separate quantifications of reductions in carbon dioxide and methane are consistent with requirements for setting clean heat targets in § 40-3.2-108(3)(d), C.R.S., and the reporting requirements in § 40-3.2-108(7)(b), C.R.S. These provisions also address the requirements in §§ 40-3.2-108(4)(c)(VI), (VII), and (XIV), C.R.S.

157. Subparagraphs (VI) through (IX) implement further statutory requirements in § 40-3.2-108(4)(c), C.R.S., regarding the contents of a CHP.

158. Subparagraph (X) requires the utility to present an analysis of the economics, from the perspective of new customers, of the choice between taking service from the utility or using electricity exclusively.

159. Subparagraphs (XI), (XII), and (XIV) implement the remaining statutory requirements in § 40-3.2-108(4)(c), C.R.S., regarding the contents of a CHP. However, the requirements regarding depreciation schedules are instead addressed in proposed subparagraph 4731(d)(I) and the requirements regarding the social cost of carbon and the social cost of methane are addressed there instead of being addressed in proposed subparagraph 4731(c)(IV).

160. Finally, subparagraph (XIII) requires the utility to identify the customers that report their own greenhouse gas emissions to the federal Environmental Protection Agency

under federal law and whose emissions are excluded from the baseline and emission reduction calculations associated with a CHP.

161. Proposed paragraph (c) lists additional required contents of the CHP, specifically those related to certain costs or benefits of the plan.

162. Subparagraph (I) addresses the costs associated with the labor-related provisions in § 40-3.2-105.5, C.R.S., in accordance with § 40-3.2-103(2)(c)(I)(B), C.R.S., as enacted by HB 21-1238.

163. As stated above, subparagraph (II) addresses the cost of related infrastructure net of avoided capital infrastructure costs in accordance with § 40-3.2-108(4)(c)(XI), C.R.S., while subparagraph (IV) addresses the social cost of carbon and the social cost of methane in accordance with §§ 40-3.2-108(4)(c)(XIII) and 40-3.2-108(6)(c)(I), C.R.S.

164. Subparagraph (III) requires the utility to provide operations costs net of avoided fuel costs for the purpose of the Commission determining whether the CHP results in a reasonable cost to customers, including savings in bills, in accordance with § 40-3.2-108(6)(d)(I)(D), C.R.S.

165. Proposed paragraph (d) lists the cost recovery components of the utility’s CHP.

166. Proposed subparagraph (I) addresses potential changes to depreciation schedules or other cost-recovery actions in accordance with § 40-3.2-108(4)(c)(XII), C.R.S.

167. Proposed subparagraph (II) addresses utility requests to recover CHP costs through a rate adjustment clause or structure that allows for current recovery under § 40-3.2-108(6)(b), C.R.S.

168. Proposed subparagraph (III) further implements the remaining provisions in § 40-3.2-108(6)(b), C.R.S.

169. Proposed paragraph (e) requires the utility to include a proposal for a competitive solicitation of certain types of clean heat resources to implement the provisions in § 40-3.2-108(4)(f), C.R.S. The proposed paragraph also requires the utility to provide its standards for interconnecting such resources with its system.

170. Proposed paragraph (f) implements labor-related requirements. For each resource, subparagraphs (I) through (III) require detailed information on Colorado labor in accordance with § 40-3.2-108(8)(b) and (d), C.R.S.

h. Rule 4732. Approval of a Clean Heat Plan.

171. Proposed paragraph (a) establishes, consistent with § 40-3.2-108(6)(d)(I), C.R.S., that the Commission shall approve a CHP if it finds the utility's proposed plan to be in the public interest. Again, consistent with the statute, the rule specifies that the Commission may modify the plan if the modifications are necessary to ensure the plan is in the public interest.

172. Proposed paragraph (b) sets out the factors the Commission will take into account in determining whether a utility's CHP is in the public interest. These factors further stem from §§ 40-3.2-108(6)(c)(II) and 40-3.2-108(6)(d)(I), C.R.S.

173. With respect to the consideration of whether the plan achieves clean heat targets, proposed subparagraphs 4732(b)(I)(A) and (B) address the provisions in § 40-3.2-108(4)(g)(I), C.R.S., that the Commission shall consult with the AQCC to estimate reductions of emissions of greenhouse gases and other air pollutants under the portfolios presented in the utility's plan and that the AQCC may participate in the utility's CHP proceedings as a party.

174. Proposed subparagraph 4732(b)(V) addresses the labor-related provisions in § 40-3.2-108(8)(d), C.R.S., that require all Commission decisions approving clean heat resources to be acquired as part of a CHP to consider the long-term impacts on Colorado's utility workforce and to place additional weight on certain labor-related factors listed in the statute.

175. Proposed paragraph (c) expands further on subparagraph 4732(b)(IV) regarding whether the utility's CHP can be implemented at a reasonable cost and rate impact. The Commission shall take into account, subject to the annual retail cost impact described next, the factors listed in the definition of "lowest reasonable cost" in § 40-3.2-108(2)(k), C.R.S.

176. Proposed paragraph (d) implements the provisions in SB 21-264 that set a "cost cap" defined at § 40-3.2-108(2)(d), C.R.S. As explained below, we use the term "annual retail cost impact" to refer to the statutory "cost cap" due to the various obligations placed on the Commission regarding the approval of a CHP in relation to both the costs of the plan and the levels of greenhouse gas emission reductions achieved by the plan.

177. Subparagraphs (I) and (II) derive from § 40-3.2-108(6)(a)(II), C.R.S., addressing the relationship between gas DSM budgets or the utility's beneficial electrification program budget and the costs of the CHP relative to the annual retail cost impact.

178. Subparagraph (III) derives from § 40-3.2-108(6)(d)(II), C.R.S., for situations where the Commission determines that the utility can achieve larger greenhouse gas emissions than its applicable clean heat targets at a cost at or below the annual retail cost impact.

179. Subparagraph (IV) derives from § 40-3.2-108(6)(d)(III), C.R.S., for situations where the cost of the utility's CHP exceeds the annual retail cost impact. The Commission

may approve such a CHP if it determines that approval of the plan is in the public interest and that certain other conditions are met regarding rate and bill impacts to customers.

180. Finally, subparagraph (V) derives from § 40-3.2-108(6)(d)(IV), C.R.S., that prohibits the Commission from requiring certain utilities from spending more than the statutory "cost cap" to comply with the clean heat targets for 2025.

i. Rule 4733. Clean Heat Plan Reporting.

181. Proposed Rule 4733 implements the statutory provisions for annual reporting in § 40-3.2-108(7), C.R.S.

182. Proposed paragraph (a) requires the utility to submit, on an annual basis, the information and calculations set forth in §§ 40-3.2-108(7)(A) and (B), C.R.S. In addition, subparagraph 4733(a)(V) addresses the reporting of information regarding the use of Colorado-based labor in accordance with § 40-3.2-108(8)(b), C.R.S.

183. Proposed paragraph (b) addresses the logistics for the utility's annual report filing and sets a deadline of August 1.

j. Rule 4734. Small Utility Clean Heat Plan.

184. Proposed Rule 4734 implements the statutory provisions for "small gas distribution utilities," (*i.e.*, jurisdictional gas utilities serving 90,000 retail customers or fewer) in § 40-3.2-108(9), C.R.S., for CHP filings to meet clean heat targets for 2025 and 2030.

185. Proposed paragraph (a) clarifies that the small utilities shall file additional CHPs in accordance with the CHP Rules unless otherwise directed by the Commission.

186. Proposed paragraph (b) lists the specific filing requirements for the 2025 and 2030 heat plans in § 40-3.2-108(9)(b), C.R.S.

187. Proposed paragraph (c) requires the Commission to approve the CHPs if it finds the plans to be in the public interest. The proposed provisions further implement the requirements in § 40-3.2-108(9)(c), C.R.S., regarding such approvals and potential modifications to the plans.

188. Proposed paragraph (d) clarifies that the utilities eligible to file a small utility CHP plan remain subject to the annual reporting requirements in proposed Rule 4733 in accordance with § 40-3.2-108(9)(d), C.R.S.

8. Demand Side Management

189. With the exception of the rule additions related to greenhouse gas emissions and the social costs of carbon and methane as described above, the modifications to the Gas Rules required to implement HB 21-1238 are found in the DSM Rules in 4 CCR 723-4.

a. Rule 4750. Overview and Purpose.

190. In accordance with HB 21-1238, we propose to add §§ 40-3.2-106 and 40-3.2-107, C.R.S., to this section.

191. Proposed paragraph (a) requires the utilities to file a DSM Strategic Issues application in accordance with § 40-3.2-103, C.R.S., as modified by HB 21-1238.

b. Rule 4751. Definitions.

192. As explained above, we propose to move the definition of “discount rate” in current paragraph (e) to the general definitions in Rule 4001 for general applicability. Likewise, we propose to move the definition of “sales customer” or “full service customer” in current paragraph (q) to the general definitions in Rule 4001 for general applicability.

193. We propose to modify the definition of "DSM program" in current paragraph (j) (re-numbered in the proposed rules as paragraph (i)) to reflect the statutory changes in § 40-1-102(6), C.R.S.

194. We propose to modify the definition of "Modified Total Resource Cost test" or "modified TRC test" in current paragraph (o) (re-numbered in the proposed rules as paragraph (n)) to reflect the statutory changes in: §§ 40-1-102(5)(b), 40-1-102(5)(b)(I), 40-1-102(5)(d), C.R.S. As described below, we further move provisions that govern the calculation of modified TRC values to paragraph 4753(m).

195. We propose to add a new defined term in proposed paragraph (p) for the term "Strategic Issues proceeding," based on the new revisions to § 40-3.2-103(1), C.R.S., in HB 21-1238.

196. We do not propose to include a definition for "behind-the-meter thermal renewable source" as set forth in § 40-1-102(1.1), C.R.S., as it is unneeded to implement the requirements in § 40-3.2-106(5), C.R.S. The definition is unneeded in the Gas DSM Rules, because HB 21-1238 requires the social cost of carbon and the social cost of methane to be used in the determination of the cost-effectiveness of all DSM measures. Likewise, the definition is unneeded to implement the new provisions in § 40-3.2-103(3.5), C.R.S., as introduced by HB 21-1238, due to the modifications to the definition of "DSM program" as explained above. We note, however, that we acknowledge the requirement in § 40-3.2-103(3.5), C.R.S., that the utility consider including incentives for behind-the-meter thermal renewable sources in the modifications to subparagraph 4753(i)(IV) regarding the costs of those incentives.

c. Rule 4752. Filing Schedule.

197. Consistent with the modifications explained below related to modified procedures for calculating the Gas Demand Side Management (G-DSM) bonus in light of the introduction of Strategic Issues proceedings, we modify the filing requirements for the G-DSM bonus in paragraph (c).

198. For efficiency, the G-DSM bonus calculation is proposed to be part of the annual advice letter adjusting the Gas Demand Side Management Cost Adjustment (G-DSMCA) as reflected in the proposed modifications to paragraph (d).

199. We also propose to add a new paragraph (f) that requires, commencing in 2022, and no less frequently than every four years thereafter, each utility to file an application to open a Strategic Issues proceeding, consistent with § 40-3.2-103(1), C.R.S.

d. Rule 4753. DSM Plan.

200. This rule sets forth requirements for utilities to file a gas DSM plan that covers a DSM period of three years (or as ordered by the Commission). We propose adding new language to this rule to specify that the utility's gas DSM plan shall demonstrate how the utility will meet or exceed energy savings goals established by the Commission pursuant to these rules through the implementation of DSM programs.

201. We also propose revisions in current paragraph (a), regarding the utility's proposed expenditures, to incorporate any requirements specified in the Commission's written order addressing the utility's most recent Strategic Issues proceeding.

202. We propose to add a new subparagraph (f)(VIII), regarding the utility's information detailing how it developed its proposed DSM program, to require the utility to include the best available values for gas leakage during the extraction, processing,

transportation, and delivery of gas by the utility as well as leakage from piping or other equipment on customer premises, and any relevant data and emissions accounting methodologies developed by the AQCC pursuant to § 25-7-140, C.R.S., regarding methane leakage rates and the appropriate global warming potential of methane, for the purpose of calculating the cost of methane emissions. This modification to paragraph (f) implements § 40-3.2-107(2)(b), C.R.S.

203. We propose revisions in the current paragraph (g) to update the nomenclature to refer to "income qualified" customers. We also propose new subparagraphs (I) through (V) that address how the utility shall target expenditures for income qualified customers. These rule modifications implement the introduction of §§ 40-3.2-107(3)(a)(III) and (IV), C.R.S., by HB 21-1238.[6]

204. We propose revisions in the current paragraph (h) to tie the utility's annual expenditure target for DSM programs to the utility's estimated budget for DSM program expenditures established by the Commission in the utility's most recent Strategic Issues proceeding. We therefore modify subparagraph (I) and likewise strike subparagraph (II).

205. We propose revisions in the current subparagraph (i)(I) to require the utility to consider within its budget that labor costs reflect compliance will all applicable labor standards set forth in § 40-3.2-105.5, C.R.S. This modification implements § 40-3.2-103(2)(c)(I)(B), C.R.S., added by HB 21-1238.

206. We also propose revisions in current subparagraph (i)(IV) to specify that customer incentive costs include any incentives for the customer's adoption of a renewable hearing or

[6] During the course of this rulemaking, we will ensure consistent terminology across the entire set of Gas Rules with respect to the change from "low income" to "income qualified."

cooling source for one or more end uses, including water heating, space heating or cooling, or industrial processes. This update is consistent with § 40-3.2-103(3.5)(a), C.R.S., as introduced by HB 21-1238.

207. We propose significant revisions in current paragraph (m) to implement the changes to the calculation of the modified TRC consistent with HB 21-1238.

208. In the new subparagraph (I), we move provisions governing the calculation of the modified TRC from the definitions in Rule 4751 and add the valuation of avoided emissions, including new provisions that address the use of the social cost of carbon and the social cost of methane. These modifications also implement the addition of § 40-1-102(5)(d), C.R.S., regarding the circumstances when the utility may present a calculation of the modified TRC without using the social costs of carbon and methane.

209. In subparagraph (II), we strike the defined non-energy benefit factor of 1.05, as non-energy benefits (other than benefits associated with the reduction of greenhouse gases as measures by the social costs of carbon and methane) will be addressed in Strategic Issues proceedings. We seek comment on whether a new value to account for other non-energy benefits from gas DSM should replace the factor of 1.05 in light of the changes to the Gas DSM Rules required by HB 21-1238.

210. In the new subparagraph (III) we propose that, for purposes of evaluating a gas DSM program or measure that incorporates innovative technologies with the potential for significant impact, the Commission may find the program or measure cost-effective, even if its initial benefit-cost ratio is not greater than one calculated using currently available data and assumptions. This is consistent with § 40-2-123(2)(b), C.R.S., as modified by HB 21-1238.

211. We further propose a new paragraph (o) that specifies, if a utility files a Strategic Issues proceeding application, its subsequent DSM plan application shall include programs and measures to meet the energy savings targets and policy goals established by the Commission in the Strategic Issues proceeding.

e. Rule 4754. Annual DSM Report.

212. Consistent with our effort to streamline DSM-related filings, we strike the provisions related to a G-DSM bonus application, because we propose to include the G-DSM bonus as part of the annual G-DSMCA filing.

213. We likewise strike paragraphs (f) through (j) due to the elimination of the gas DSM application filing and the determinations regarding the G-DSM bonus to be made in the utilities' Strategic Issues proceedings. As explained below, however, certain provisions in these paragraphs are modified and moved to Rule 4760 that more fully develops the G-DSM bonus.

f. Rule 4756. General Provisions Concerning Cost Allocation and Recovery.

214. This rule addresses cost allocation and recovery for utility DSM programs.

215. We propose to revise paragraph (b), which addresses fuel switching, to specify both that the Commission shall not prohibit utilities form offering programs or incentives that encourage customers to replace gas-fuel appliances with efficient electric appliances but also, consistent with the express language in § 40-3.2-103(3.5)(b), C.R.S., that the Commission will not, however, require the removal of gas-fueled appliances or equipment from an existing structure. Along with these changes, we deleted the current rule language that excluded fuel switching from gas to other fossil fuel energy from a gas utility's DSM program.

216. We propose a new paragraph (e) that addresses decoupling consistent with the direction in § 40-3.2-103(5)(b), C.R.S. The proposed rule specifies that the utility may file for approval of a revenue decoupling mechanism to remove disincentives to the implementation of effective gas DSM programs.

g. Rule 4760. Gas DSM Bonus (G-DSM Bonus).

217. This rule addresses the utility's DSM bonus applications.

218. We propose a new paragraph (a) to specify that the level of bonus for which the utility is eligible will be consistent with the bonus framework established in the utility's most recent Strategic Issues proceeding. We also propose complementary revisions to the current introduction of the rule in a new paragraph (c).

219. We propose to modify paragraph (c) to eliminate the rule language stating the utility may request a G-DSM bonus by application, given that the framework for the G-DSM bonus will be determined in the Strategic Issues proceeding. We therefore strike most of the current paragraph (c). However, we retain the provision that the G-DSM bonus shall not count against the utility's authorized rate-of-return, and, as explained below, we retain the cap on the G-DSM bonus at 20 percent of net economic benefits or 25 percent of expenditures but move it to a separate paragraph.

220. We propose revisions to subparagraph (d)(IV), which requires the utility to provide in its G-DSM bonus calculations, actual gas savings and techniques used to calculate the gas savings for the prior G-DSMCA period. We propose to add to this rule language specifying that the actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, should be used to determine net economic benefits for the purpose of calculating the bonus.

221. We also propose to add a new subparagraph (d)(VII), which requires the utility to provide in its G-DSM bonus filing any additional information required by the Commission in the utility's most recent Strategic Issues proceeding.

222. In the new paragraph (e), we propose to retain the feature in the current subparagraph 4754(h)(I) that accounts for the circumstances when the modified TRC value for income qualified programs is below 1.0 in relation to the G-DSM bonus. We also propose to exclude the benefits from those programs in the determination of the net economic benefits in the bonus calculation if the utility has not expended its budget on income qualified programs.

223. In the new paragraph (f), we propose to retain the feature in the current paragraph 4754(i) that caps the G-DSM bonus at 20 percent of net economic benefits or 25 percent of expenditures.

224. In the new paragraph (g), we propose to retain the features in the current paragraph 4754(j) regarding the impact of the gas DSM on the utility's authorized rate-of-return and regarding the recovery of the bonus through the G-DSMCA over a 12-month period.

225. Finally, we propose a new paragraph (h) that conditions the G-DSM bonus upon a showing that the utility did not impair beneficial electrification.

h. Rule 4761. Filing of DSM Strategic Issues Application.

226. We propose to add this new rule that will address the filing of a utility's Strategic Issues application, as required by the revisions to § 40-3.2-103(1), C.R.S., as enacted by HB 21-1238.

227. Proposed paragraph (a) sets forth a July 1, 2022 initial deadline for each utility to file an application to open a Strategic Issues proceeding. This paragraph specifies that these

proceedings shall result in the development of energy savings goals to be achieved by the utility, taking into account its potential for cost-effective DSM as well as Colorado's greenhouse gas emissions reduction goals in accordance with § 25-7-102(2)(g), C.R.S.

228. Proposed paragraph (b) requires each utility to provide in its Strategic Issues application, an estimated DSM budget commensurate with proposed energy savings goals, funding, and cost-recovery mechanisms, and a financial bonus structure for DSM programs implemented by the utility. Subparagraph (III) requires the utility to provide an analysis of the comparative economics of DSM measures and programs relative to beneficial electrification, particularly for new construction.

229. Proposed paragraph (c) specifies, if the filing of a Strategic Issues application overlaps with the filing of a DSM plan application, a utility with 250,000 or more full-service customers may request Commission approval of an *extension* of its currently-effective DSM plan until the Strategic Issues proceeding is concluded. This is intended to avoid a conflict where a utility could have occasion to file overlapping Strategic Issues and DSM plan applications at the same time. This rule ensures that, in such circumstance, the Strategic Issues proceeding should take precedence over the DSM plan proceeding.

230. In parallel to proposed paragraph (c), proposed paragraph (d) implements § 40-3.2-103(c)(2.5), C.R.S., specifying a utility with fewer than 250,000 full-service customers can combine a Strategic Issues proceeding with a DSM plan filing.

231. Finally, proposed paragraph (e) provides that, in its decision addressing the utility's Strategic Issues application, the Commission will establish energy savings goals for the utility to be addressed by future DSM plan filings, an estimated budget for DSM program

expenditures that is commensurate with the energy savings goals, and a structure for any DSM bonus to be awarded to the utility.

9. Other Rules

232. We include in the rules attached to this Decision in Attachments A and B, certain sections of the Gas Rules that may require revisions for the future implementation of clean heat resources included in an approved CHP. These rules include: 4200. Construction, Installation, Maintenance, and Operation; 4201. Instrumentation; 4202. Heating Value, Purity, and Pressure; and 4203. Interruptions and Curtailments of Service.

233. Although we do not propose modifications to these particular rules at this time, we pose the following questions for comments from the rulemaking participants:

- Are there available models for standards for the interconnection process for alternative fuels (*e.g.*, hydrogen and biomethane) to be injected into the utility's gas pipeline system?
- Are there available best practice or standards for purity, monitoring, and metering of alternative fuels (*e.g.*, hydrogen and biomethane) being injected into a utility's gas pipeline system?

234. We also include in the rules attached to this Decision, additional sections of the Gas Rules that may require modification revisions related to the Commission's implementation of the requirements in SB 21-272 related to disproportionately impacted communities and income qualified customers. Although no specific modifications to these other rules are proposed, these sections of the rules are included in Attachments A and B to preserve the ability to modify these rules, as necessary, during the course of this rulemaking that will continue through the end of November 2022.

235. Notwithstanding the inclusion of these other rules in Attachments A and B, the Commission may address modifications to these sections in other rulemaking proceedings,

including the rulemaking proceeding required by § 40-2-108(3), C.R.S., in accordance with SB 21-272.

E. Conclusion

236. The statutory authority for the rules proposed here is found at: §§ 29-20-108, 40-1-103.5, 40-2-108, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-3-101, 40-3.2-103, 40-3.2-106, 40-3.2-107, 40-3.2-108, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-117, 40-7-113.5, 40-7-116.5, and 40-8.7-105(5), C.R.S.

237. The proposed rules in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) are available through the Commission's Electronic Filings (E-Filings) System at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=21R-0449G

238. The Commission encourages and invites public comment on all proposed rule amendments. We request that commenters propose any changes in legislative redline format.

239. The Commission will conduct a hearing on the proposed rules and related issues on February 17 and 18, 2022. Interested persons may submit written comments on the rules and present these orally at hearing unless the Commission deems oral presentations unnecessary.

240. The Commission encourages interested persons to submit written comments before the hearing date specified in this NOPR. In the event interested persons wish to file comments before the hearing, the Commission requests that comments be filed no later than January 25, 2022, and that any pre-filed comments responsive to the initial comments be submitted no later than February 8, 2022. The Commission prefers that comments be filed using the Commission's E-Filings System under this Proceeding at:

https://www.dora.state.co.us/pls/efi/EFI.homepage.

241. Consistent with the discussion above, the Commission will establish additional procedures by a separate Decision.

II. ORDER

A. The Commission Orders That:

1. This Notice of Proposed Rulemaking (including Attachment A and Attachment B) shall be filed with the Colorado Secretary of State for publication in the October 25, 2021 edition of *The Colorado Register*.

2. A hearing on the proposed rules and related matters shall be held as follows:

DATES: February 17 and 18, 2022

TIME: 9:00 a.m. until no later than 5:00 p.m.

PLACE: Commission Hearing Room A
1560 Broadway, Suite 250
Denver, Colorado[7]

3. At the time set for hearing in this matter, interested persons may submit written comments and may present these orally unless the Commission deems oral comments unnecessary.

4. Interested persons may file written comments in this matter. The Commission requests that initial pre-filed comments be submitted no later than January 25, 2022, and any pre-filed comments responsive to the initial comments be submitted no later than February 8, 2022. The Commission will consider all submissions, whether oral or written.

5. The Commission will establish additional procedures by a separate Decision, consistent with the discussion above.

[7] If COVID-19 protocols then in effect require that the hearing be conducted remotely instead of in-person, the hearing will be held by video conference using Zoom at a link that will be provided in the calendar of events posted on the Commission's website, publicly accessible at: https://puc.colorado.gov/.

6. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING September 22, 2021.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners