Decision No. C24-0278

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24R-0192G

IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-4, TO IMPLEMENT CERTAIN PROVISIONS IN SENATE BILL 23-291 ADDRESSING MECHANISMS TO ALIGN THE FINANCIAL INCENTIVES OF INVESTOR-OWNED GAS UTILITIES WITH THE INTERESTS OF THE UTILITY'S CUSTOMERS REGARDING INCURRED FUEL COSTS.

NOTICE OF PROPOSED RULEMAKING

Mailed Date: April 30, 2024
Adopted Date: April 3, 2024

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I. BY THE COMMISSION

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), to implement certain provisions in § 40-3-120, C.R.S., enacted by Senate Bill (SB) 23-291. The proposed amendments to the Gas Rules are intended to protect Colorado gas utility customers while also improving the gas utilities' management of fuel costs. The proposed rules further establish a symmetrical incentive mechanism that aligns the financial incentives of the gas utilities with the interests of their customers regarding incurred fuel costs. The proposed amendments to the Gas Rules required by § 40-3-120, C.R.S., continue the utilities' implementation of gas risk management plans and replace the requirements for the Gas Performance Incentive Mechanism (GPIM) established in Proceeding No. 21R-0314G with a new incentive mechanism in accordance with SB 23-291.

2. The statutory authority for the proposed rules is found generally at § 40-1-103.5, C.R.S. (authorizing the Commission to promulgate implementing rules) and more specifically in § 40-3-120(2), C.R.S., as enacted by SB 23-291.

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

4. The Commission designates Chairman Eric Blank as Hearing Commissioner, pursuant to § 40-6-101(2)(a), C.R.S., for this rulemaking proceeding. The Hearing Commissioner will hold a public hearing on the proposed rules on July 11, 2024.

5. The Commission encourages interested persons to submit written comments before the hearing scheduled in this matter. Initial written comments are to be filed no later than May 31, 2024, and any written comments responsive to the initial comments are to be filed no later than June 14, 2024.

B. Utility Tariff and Rate Provisions in SB23-291

6. Colorado legislators convened a Joint Select Committee on Rising Utility Rates (Joint Select Committee) during the first regular session of the 2023 General Assembly. The Joint Select Committee was charged with investigating the root cause of the recent increases in utility rates facing Coloradans and with considering potential policy interventions. The Joint Select Committee sought to better understand current utility rates and customer bills, how rates and bills increased to current levels, and various policy means to prevent future unexpected and steep utility rate increases. The efforts of the Joint Select Committee culminated in the passage and enactment of SB23-291.[1]

7. SB23-291 includes several sections that add provisions to or modify existing provisions within Title 40 and thus alters the Commission's regulation of Colorado's investor-owned electric and natural gas utilities. Only certain provisions within SB23-291 will be addressed in this rulemaking proceeding. Other provisions of SB23-291 have already been implemented by the Commission, are being implemented in other ongoing proceedings, or are slated to be implement in future proceedings in the next few years.

8. For example, Section 4 of SB23-291 requires each investor-owned gas utility to file with the Commission, on or before November 1, 2023, a Gas Price Risk Management (GPRM) plan that includes proposals for addressing the volatility of fuel costs recovered from the utility's

[1] Description of committee and committee schedule, materials, and documents available at: https://leg.colorado.gov/committees/joint-select-committee-rising-utility-rates/2023-regular-session.

customers pursuant to the utility's Gas Cost Adjustment (GCA) filings.[2] A GPRM was established for each of Colorado's four investor-owned gas utilities through utility application proceedings that concluded in November 2023.[3] As discussed below, the rules proposed in the attachments to this Decision establish the on-going requirement that Colorado gas utilities implement a GPRM through their GCA filings.

9. Section 4 also requires the Commission to adopt rules, on or before January 1, 2025, to establish "mechanisms that align an investor-owned utility's financial incentives with the financial interests of its customers regarding incurred fuel costs."[4] The rules proposed in the attachments to this Decision establish a GPIM based on stakeholder outreach conducted after the enactment of SB23-291.

10. The combination of the rules addressing the GPRM and the GPIM satisfy the specific requirement in § 40-3-120(2)(b), C.R.S., that the rules adopted by the Commission both protect gas utility customers, in this instance through a reduction in the volatility of gas commodity costs recovered through the utilities GCAs, and improve the utility's management of gas commodity costs, as proposed here through the alignment of financial incentives.

C. Stakeholder Outreach Prior to Permanent Rulemaking

11. The Commission initiated pre-rulemaking activities in Proceeding No. 23M-0493EG in October 2023. The Commission opened the proceeding by Decision No. C23-0670 to receive comments, suggestions, and proposals for modifications to the GCA Rules

[2] § 40-3-120(1), C.R.S.

[3] *See*, Proceeding No. 23A-0533G for Public Service Company of Colorado; Proceeding No. 23A-0538G for Colorado Natural Gas, Inc.; Proceeding No. 23A-0539G for Atmos Energy Corporation; and Proceeding No. 23A-0540G for Black Hills Colorado Gas, Inc.

[4] § 40-3-120(2), C.R.S.

within the Gas Rules at 4 CCR 723-4-4600*, et seq*. Chairman, Eric Blank, also served as Hearing Commissioner for that proceeding.

12. As part of that decision launching the pre-rulemaking, the Commission suggested that after a review of various risk-mitigation mechanisms in other states, an approach that may be suited to Colorado as envisioned in SB23-291 is implemented by Hawaiian Electric Company (HECO) through its Energy Cost Recovery Clause (ECRC).

13. The Hawaii Public Utilities Commission adopted the ECRC to provide HECO with "some 'skin in the game' by exposing HECO to risks in fuel cost changes" and "at least some incentive to manage and avoid risks associated with fossil fuel price volatility".[5] Under this clause, 98 percent of the difference between a baseline fuel cost and the actual fuel cost is recovered from customers, subject to a +/- $2.5 million annual revenue exposure cap

14. In the hopes of spurring rigorous debate, a proposed approach for how the ECRC framework might be applied to a Colorado utility was attached to Decision No. C23-0670. The Commission explained that the potential risk-mitigation measure was intended to align incentives such that the utilities "win when customers win and vice versa." The Commission also posited that the proposed mechanism would provide the Commission with early warning signals about increases in gas commodity market prices such as those experienced during the 2022-2023 heating season that prompted the General Assembly's establishment of the Joint Select Committee.

15. Five utilities responded to the proposal put forth in Decision No. C23-0670.

16. For its part, Durango Mountain Utilities argues that the mitigation measures should not apply to small propane distribution utilities like itself.

[5] Public Utilities Commission of the State of Hawaii, Docket No. 2016-0328, Final Decision and Order No. 35545, filed June 22, 2018, at 62-63.

17. Atmos Energy Corporation (Atmos) states that the Commission had already largely undertaken the task of aligning financial incentives when it promulgated the GPIM structure in Proceeding No. 21R-0314G. Atmos contends that the current GPIM now within the GCA Rules is a reasoned approach resulting from stakeholder input and that the GPIM should serve as the starting point for any additional changes brought about by SB23-291. In Atmos' view, the current GPIM is more flexible than the ECRC and could be tailored to each utility's parameters. In contrast, Atmos criticizes the ECRC and Commission's proposal in Decision No. C23-0670 as having an inflexible cap and relying on historical baselines that were suboptimal. Atmos argues that reported market indices were a more appropriate benchmark for baseline gas costs than were costs incurred over a prior period. It also described what it viewed as inconsistencies with the Commission's approach to recovery of gas costs across recent proceedings.

18. Colorado Natural Gas, Inc. (CNG) also references the current GPIM rules, praising the exclusion for utilities with fewer than 50,000 customers. CNG requests that any proposed rules maintain the carve out for gas utilities with fewer than 50,000 customers, and it also opines that a reexamination of PIMs would be better served on a utility-by-utility basis, rather than a one-size-fits all approach that would be codified in rule. Turning to the Commission's proposal, CNG observes that the baseline scenarios tie the incentive to market prices which are outside the utility's control and urges the Commission to consider forward-looking price benchmarks. CNG also points out that larger utilities may have more resources to mitigate some incurred gas costs, but smaller utilities lack those resources and are similarly less able to absorb the penalties associated with the proposal. Finally, CNG states that any mechanism under consideration should include a *force majeure* clause that would protect the utility from unforeseen weather events outside of its control.

19. Black Hills Colorado Gas, Inc. and Black Hills Colorado Electric, LLC (together, Black Hills) jointly filed comments addressing risk-mitigation mechanisms like the HECO mechanism, unintended consequences of a risk-mitigation tool, and possible alternative paths for consideration. Black Hills points out that it is a "price-taker" on the gas market and is therefore at the mercy of unregulated natural gas suppliers when it procures gas for customers. Black Hills points out that it has limited levers that could be pulled to ensure that its real-time purchases of gas are below a baseline set by historic gas costs. Black Hills also contends that evaluating incurred fuel costs relative to a historic baseline does not allow the company to improve its management of fuel costs because it must take natural gas at the market price. Moreover, Black Hills argues that the proposal will put pressure on its gas purchasing team to avoid penalties and chase profits, which moves away from the current structure where the team is obligated to act prudently in ensuring supply, and where there is no profit motive. Black Hills also suggests that one rational response to the proposed mechanism could be for the utility to overbuy baseload gas to mitigate its risk vis-à-vis the benchmark, and then be left to offload excess gas in the market. Black Hills suggests that the proposed mechanism may increase its financial risk when it is unable to recover all of its incurred gas costs. Black Hills suggests some alternative paths to consider such as: excluding gas commodity costs associated with certain storage withdrawals and limiting the risk-mitigation mechanism to only certain gas purchases, such as firm peaking contracts or daily spot market purchases. Black Hills also cautions against overly prescriptive rules that do not work for all utilities.

20. Public Service Company of Colorado (Public Service) contends that the statutory intent of SB23-291 is best served by incentivizing the use of long-term contracts and physical

storage. Public Service further articulates certain principles that it believes the Commission should consider in designing a fuel cost incentive mechanism.

21. Applying these principles, as well as the statutory language in SB23-291, Public Service suggests that gas withdrawn from storage be exempted from the incentive mechanism, that the baseline for the incentive mechanism should be derived from factors within the utility's control and that long-term fixed contracts and additional storage should be developed as tools to reduce volatility. Public Service also argues for a baseline derived from market indices when and where gas was purchased and the exclusion from the incentive mechanism of deferred balances and longer-term fixed price contracts for gas supplies. Public Service also suggests the Commission consider lower incentive caps and risk sharing percentages, while moving dead bands to be sized around historical volatility of gas commodity prices. Finally, Public Service calls for the incentive mechanism to work in harmony with existing plans and programs, as well as the exclusion from the incentive mechanism of gas purchases reviewed outside the utility's Gas Purchase Plan or GPRM.

D. Proposed Rule Changes

22. The changes to the GCA Rules proposed in the attachments to this Decision are intended as a point from which to continue the conversation begun in the pre-rulemaking in Proceeding No. 23M-0493EG. The rules proposed here may not represent as much of a departure from the Commission's proposal put forth in Decision No. C23-0670 as some stakeholders suggest, but the Commission remains open to continued discussion of these proposed rules as well as additional approaches.

1. Rule 4600 – Overview and Purpose

23. Rule 4600 is modified to expand the stated purpose of the GCA Rules in accordance with SB 23-291 and to remove references to GPIM Applications (which these rules are meant to replace), while leaving reference to gas performance mechanisms generally.

2. Rule 4601 – Definitions

24. Proposed Rule 4601 adds two new defined terms that are used in the modified GPIM: "Actual Total Gas Cost" and "Actual Total Gas Quantity."

25. The proposed rule also removes legacy references to the GPIM application process and GPIM benchmark.

3. Rule 4602 – Schedule for Filings by Utilities

26. Proposed paragraph 4602(f) requires the utility's GCA to include a gas price risk management plan as initially implemented by the utilities through the 2023 application filings required by § 40-3-120(1), C.R.S. The proposed rule further specifies that modifications to a utility's gas risk management plan must be accomplished through an application proceeding separate from a GCA filing.

27. Proposed paragraph 4602(g) removes the reference to the legacy GPIM application process, but the exemption for utilities with fewer than 50,000 full service customers remains.

28. Proposed paragraph 4602(h) is modified to remove references to the legacy GPIM application process and requires utilities with more than 50,000 full service customers to include a GPIM in the next GCA filing after the effective date of the rules adopted pursuant to § 40-3-120(2), C.R.S.

29. Paragraphs 4602(h) and (i) which deal with the legacy GPIM process are removed.

4. Rule 4603 – Gas Cost Adjustments

30. Proposed paragraph 4603(g) requires the utility's GCA to be subject to the principal requirements of a gas price risk management plan as set forth in SB 23-291. The proposed rule further requires that the gas price risk management plan include a minimum threshold, consistent with the gas utility applications approved by the Commission in November 2023 pursuant to § 40-3-120(1), C.R.S.

5. Rule 4604 – Contents of GCA Filings

31. Proposed paragraph 4604(d) requires the utility's GCA filing to include information on the utility's gas price risk management plan and the proposed GPIM within the presentation of its GCA deferred gas cost calculation. The proposed rule also requires the information on the symmetric sharing amount of the GPIM to be provided as an executable work paper.

32. Proposed subparagraph 4606(g)(II) recognizes that the amount of the GCA to be billed to customers upon the Commission's approval of a GCA filing may be subject to the terms of the utility's gas price risk management plan and GPIM.

6. Rule 4607 – Gas Performance Incentive Mechanism

33. Proposed paragraph 4607(a) sets forth the new symmetric sharing mechanism contemplated in § 40-3-120(2), C.R.S. Proposed paragraph 4607(a) replaces most of rule 4607 adopted in Proceeding No. 21R-0314G.

34. The GPIM benchmark gas rate defined in proposed subparagraph 4607(a)(I) equals the actual total gas cost divided by the actual total gas quantity for the most recently concluded quarterly period in the previous calendar year, while proposed subparagraph 4607(a)(II) defines the GPIM actual gas rate to equal the actual total gas cost divided by the actual gas quantity purchased in the most recently concluded quarterly period. Proposed subparagraph 4607(a)(III)

then defines the GPIM sharing amount to be a percentage of the difference between the two rates defined in the previous two subparagraphs of the proposed rule (*i.e.*, five percent as shown in the rules attached to this Decision) multiplied by the actual total gas quantity purchased. Subparagraph 4607(a)(IV) further provides that the quarterly sharing amount will be recovered through the utility's GCA deferred account balance.

35. The purpose of this proposed GPIM is to help smooth the volatility and capture the directionality of gas prices by sharing a percentage of gas costs with the utility instead of all costs being passed directly through to the customer. We invite stakeholder comment on this method.

36. For simplicity and to account for seasonality, for example, the benchmark gas cost is based on the same quarterly period from the previous year. The use of a historic baseline instead of future market index prices is further intended to achieve the goal of smoothing gas prices over time. We recognize, however, that there are other ways to calculate a GPIM sharing amount and welcome proposals for other baseline calculation methods using backward looking prices; but for the reasons just articulated the Commission remains skeptical of proposals for baseline calculations using forward looking prices.

37. Notably, the proposed rule provides symmetric sharing at five percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate. Subparagraph 4607(a)(III)(A) provides a deadband whereby no sharing occurs (unless the difference between the GPIM benchmark and GPIM actual gas rate is greater than 20 cents per dekatherm), in accordance with the requirements set forth in § 40-3-120(2), C.R.S. The proposed deadband of $0.20 per dekatherm is intended to account for the natural fluctuation of gas commodity prices. Subparagraph 4607(a)(III)(B) likewise sets a cumulative rolling twelve-month cap on the symmetric sharing amount equal to a 40-basis point pre-tax return on the most recent

Commission-approved rate base for each utility (akin to change in the utility's Weighted Average Cost of Capital but without the need to use a full cost of service model to derive a fraction of a base rate revenue requirement). Public Service recommended that an annual cap be based on a basis point change in the utility's authorized return on equity (ROE). However, we prefer a basis point return on rate base because it scales with each utility.

38. We are also interested to hear from stakeholders about the proposed method for recovery of the GPIM through the deferred account balance. This approach seems reasonable because it spreads the impact of the GPIM over one year.

39. We also request that the utilities that would be subject to the proposed GPIM provide in this Proceeding an historical analysis of how the proposed GPIM would have functioned over the past five to ten years.

40. Finally, although not described in proposed rules in the attachments to this Decision, an alternative to the new GPIM approach outlined here would be to include a certain percentage of gas costs in base rates through the litigated rate case process. This alternative approach would accomplish similar results because the amount recovered through base rates is generally determined based on a historical test period and would not change despite gas prices increasing or decreasing. This is the way fuel costs were recovered through base rates in the past, as reflected in the defined term "base gas cost" in rule 4601. The proposed rules in the attachments to this Decision likely offer a simpler and more direct way to accomplish the same goals, and thus we welcome comments on this alternative approach.

7. Rule 4608 – Gas Purchase and Deferred Balance Reports and Prudence Reviews

41. We propose modifications throughout rule 4608 that set forth the filing requirements and prudence review procedures for the Utility Gas Purchase and Deferred Balance Report (GPDBR).

42. We also propose to eliminate the option for GPIM shared savings in paragraph 4608(d) as the symmetrical GPIM sharing amount is determined by rule 4607 in accordance with § 40-3-120(2), C.R.S.

8. Rule 4609 – Contents of the GPDBR

43. Reporting requirements relative to the utility's gas price risk management plan and GPIM are shown in the proposed amendments to rule 4609.

44. For example, proposed paragraph 4609(a) requires each gas utility to provide in attachment No. 1 to the GPDBR a description and explanation of: the volumes and costs associated with fixed-price, long-term supply contracts; the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and the volumes and costs associated with associated with financial hedging.

45. Attachment 6 to the GPDBR will likewise include the calculations to determine GPIM benchmark gas rates and GPIM actual gas rates, quarterly and cumulative GPIM amounts, and the value of the cap, as shown in proposed paragraph 4609(f).

E. Conclusion

46. Through this NOPR, the Commission solicits comments from interested persons on the amendments proposed in this Decision and its attachments. Interested persons may file written comments including data, views, and arguments into this Proceeding for consideration. The Commission also welcomes submission of alternative proposed rules, including both

consensus proposals joined by multiple rulemaking participants and individual proposals. Participants are encouraged to provide redlines of any specific proposed rule changes.

47. The Commission designates Chairman Eric Blank as Hearing Commissioner, pursuant to § 40-6-101(2)(a), C.R.S., for this rulemaking proceeding. The Hearing Commissioner will hold a public hearing on the proposed rules at the below-stated time and place. In addition to submitting written comments, participants will have an opportunity to present comments orally at the hearing, unless the Hearing Commissioner deems oral presentations unnecessary.

48. The proposed rules in legislative (*i.e.,* strikeout/underline) format (Attachment A) and final format (Attachment B) are available through the Commission's E-Filings system at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=24R-0192G.

49. Initial written comments on the proposed rule changes are requested by May 31, 2024. Any person wishing to file comments responding to the initial comments is requested to file such comments by June 14, 2024. These deadlines are set so that the comments and responses may be considered at the public hearing, nonetheless, persons may file written comments into this Proceeding at any time.

50. The Commission prefers comments be filed using the Commission's E-Filings System at https://www.dora.state.co.us/pls/efi/EFI.homepage under this Proceeding No. 24R-0192G.

51. The Commission will consider all comments submitted in this Proceeding, whether oral or written.

II. ORDER

A. The Commission Orders That:

1. This Notice of Proposed Rulemaking (including Attachments A and B) shall be filed with the Colorado Secretary of State for publication in the May 10, 2024 edition of *The Colorado Register*.

2. The Commission designates Chairman Eric Blank as Hearing Commissioner, pursuant to § 40-6-101(2)(a), C.R.S., for this rulemaking proceeding.

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

DATE	July 11, 2024
TIME:	9:00 a.m. until no later than 5:00 p.m.
PLACE:	By video conference using Zoom at a link in the calendar of events on the Commission's website: https://puc.colorado.gov/puccalendar

4. 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.

5. Interested persons may file written comments in this matter. The Commission requests that initial pre-filed comments be submitted no later than May 31, 2024, and that any pre-filed comments responsive to the initial comments be submitted no later than June 14, 2024. The Commission will consider all submissions, whether oral or written. The Commission prefers comments be filed into this Proceeding using the Commission's E-Filings System at: https://www.dora.state.co.us/pls/efi/EFI.homepage.

6. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING April 3, 2024.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E White

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners