Decision No. C24-0702

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24R-0410E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, TO IMPLEMENT CERTAIN PROVISIONS IN SENATE BILL 23-291 ADDRESSING MECHANISMS TO ALIGN THE FINANCIAL INCENTIVES OF INVESTOR-OWNED ELECTRIC UTILITIES WITH THE INTERESTS OF THE UTILITY'S CUSTOMERS REGARDING INCURRED FUEL COSTS.

NOTICE OF PROPOSED RULEMAKING

Issued Date: September 30, 2024
Adopted Date: September 18, 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 Electric Utilities, 4 *Code of Colorado Regulations* ("CCR") 723-3 ("Electric Rules"), to implement certain provisions in § 40-3-120, C.R.S., enacted by Senate Bill ("SB") 23-291. The proposed amendments to the Electric Rules are intended to protect Colorado electric utility customers while also improving the electric utilities' management of fuel costs. The proposed rules further establish a symmetrical incentive mechanism that aligns the financial incentives the electric utilities with the interests of their customers regarding incurred gas commodity fuel costs. Notwithstanding the focus of the proposed rules on gas commodity fuel costs, the Commission is interested in the question whether there is a need for rules that address symmetrical incentive mechanisms for other fuels used for the generation of electricity.

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 Electric 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 will hold a public hearing on the proposed rules on November 5, 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

October 17, 2024, and any written comments responsive to the initial comments are to be filed no later than November 1, 2024.

B. Utility Tariff and Rate Provisions in SB 23-291

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 SB 23-291.[1]

7. SB 23-291 includes several sections that added provisions to or modified 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 SB 23-291 will be addressed in this rulemaking proceeding. Other provisions of SB 23-291 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 SB 23-291 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 customers pursuant to the utility's Gas Cost Adjustment filings.[2] A GPRM was

[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.

[2] § 40-3-120(1), C.R.S.

established for each of Colorado's four investor-owned gas utilities through utility application proceedings that concluded in November 2023.[3]

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 Commission is developing such rules for the Colorado gas utilities in Proceeding No. 24R-0192G. The rules proposed in the attachments to this Decision establish a similar symmetrical sharing mechanism for the electric utilities. Furthermore, for the electric utilities, the Commission must also consider mechanisms to improve electricity production cost efficiency while minimizing fuel costs as part of its consideration of the rules required by § 40-3-120(2)(a), C.R.S.

C. Stakeholder Outreach Prior to Permanent Rulemaking

10. 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 Electric Rules.

11. As part of the decision launching the pre-rulemaking, Decision No. C23-0670, 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 SB 23-291 is implemented by Hawaiian Electric Company ("HECO") through its Energy Cost Recovery Clause ("ECRC").

12. 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

[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.

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.

13. 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.

14. Both investor-owned electric utilities in Colorado responded to the proposal put forth in Decision No. C23-0670.

15. Black Hills Colorado Electric, LLC (“Black Hills”) 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. 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

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

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 there is no profit motive. Black Hills also suggests that one rational response to the proposed mechanism could be for the utility to over purchase 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 some alternative paths to consider such as: 1) excluding gas commodity costs associated with certain storage withdrawals; and 2) limiting the risk-mitigation mechanism to only certain gas purchases, firm peaking contracts, or daily spot market purchases. Black Hills also cautions against overly prescriptive rules that do not work for both utilities.

16. Public Service Company of Colorado ("Public Service") contends that the statutory intent of SB 23-291 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.

17. Applying these principles, as well as the statutory language in SB 23-291, 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.

D. Proposed Rules

18. We propose to introduce a new section within the Electric Rules to implement § 40-6-101(2)(a), C.R.S., titled Fuel Cost Recovery and Electricity Production Cost Efficiency. The introduction of these new provisions is intended as a point from which to continue the conversation begun in the pre-rulemaking in Proceeding No. 23M-0493EG. The Commission remains open to continued discussion of these proposed rules as well as additional approaches.

1. Rule 3860 – Overview and Purpose

19. Rule 3860 states purpose of the new provisions for Fuel Cost Recovery and Electricity Production Cost Efficiency in accordance with SB 23-291.

2. Rule 3861 – Definitions

20. Proposed Rule 3651 defines three terms: "Gas Commodity Fuel Performance Incentive Mechanism" or "E-GPIM," "E-GPIM Total Gas Cost," and "E-GPIM Total Gas Quantity."

3. Rule 3862 – Gas Commodity Fuel Performance Incentive Mechanism

21. Proposed paragraph 3862(a) requires the electric utilities to include a E-GPIM in their rate adjustment filings used for the recovery of purchased fuel costs for electricity production. This rate adjustment is the Electric Commodity Adjustment for Public Service[6] and the Energy Cost Adjustment for Black Hills.[7]

22. Proposed paragraph 3862(b) sets a deadline for the utilities to file the necessary tariff sheets to introduce a E-GPIM into the Electric Commodity Adjustment for Public Service and the Energy Cost Adjustment for Black Hills.

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[6] Public Service Company of Colorado, Colo. PUC No. 8, Sheet Nos. 143 through 143H.

[7] Black Hills Colorado Electric, LLC, Colo. PUC No. 11, Sheet Nos. 61 through 65.

23. Proposed paragraph 3862(c) sets forth the symmetric sharing mechanism that will be the centerpiece of the electric utility's E-GPIM.

24. The E-GPIM benchmark gas rate defined in proposed subparagraph 3862(c)(I) equals the E-GPIM total gas cost divided by the E-GPIM total gas quantity for the most recently concluded quarterly period in the previous calendar year, while proposed subparagraph 3862(c)(II) defines the E-GPIM actual gas rate to equal the E-GPIM total gas cost divided by the E-GPIM gas quantity purchased in the most recently concluded quarterly period. Proposed subparagraph 3862(c)(III) then defines the E-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.*, 5 percent as shown in the rules attached to this Decision) multiplied by the E-GPIM total gas quantity purchased. Subparagraph 3862(c)(IV) further provides that the quarterly sharing amount will be recovered through the deferred account balance for the Electric Commodity Adjustment for Public Service and the Energy Cost Adjustment for Black Hills.

25. The purpose of this proposed E-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. This serves the purpose of aligning utility and customer experience creating the "win-win" or "lose-lose" structure contemplated in SB 23-291.

26. Notably, the proposed rule provides symmetric sharing at 5 percent of the difference between the E-GPIM benchmark gas rate and the E-GPIM actual gas rate. Subparagraph 3862(c)(III)(A) provides a deadband whereby no sharing occurs (unless the difference between the E-GPIM benchmark and E-GPIM actual gas rate is greater than twenty 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 3862(c)(III)(B) likewise sets a 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).

27. Proposed paragraph 3862(d) requires that the utility provide workpapers in executable format showing the calculation of the symmetric sharing amount included in the deferred balance for the Electric Commodity Adjustment for Public Service and for the Energy Cost Adjustment for Black Hills.

28. Proposed paragraph 3862(e) states that the Commission may examine the implementation of the E-GPIM in the utility's established prudence review process. Proposed subparagraph 3862(e)(I) requires the utility to provide the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by electric production facility, that the utility purchased to generate electricity for each month of the calendar year in its prudence review filing for the Electric Commodity Adjustment for Public Service and the Energy Cost Adjustment for Black Hills. In accordance with proposed subparagraph 3862(e)(II), the prudency review filing must also include: the quarterly E-GPIM benchmark gas rates and E-GPIM actual gas rates; the quarterly and twelve-month cumulative E-GPIM sharing amounts; and the calculation of cap on the annual cumulative E-GPIM sharing amount.

29. Finally, we request that Public Service and Black Hills provide in this Proceeding an historical analysis of how the proposed E-GPIM would have functioned over the past five to ten years.

4. Electric Generation Fuels Other than Natural Gas

30. As explained above, Section 4 of SB 23-291 requires the Commission to adopt rules to establish mechanisms that align an investor-owned utility's financial incentives with the financial interests of its customers regarding incurred fuel costs. This provision, codified at § 40-3-120(2), C.R.S., may not apply exclusively to natural gas.

31. We solicit comments on whether the Commission should examine the development of additional symmetrical incentive mechanisms regarding incurred costs for other fuels used to generate electricity such as coal.

5. Rule 3863 – Electricity Production Cost Efficiency

32. Section 40-3-120(3)(a)(II), C.R.S., requires the Commission to consider mechanisms to improve electricity production cost efficiency while minimizing fuel costs as part of its consideration of the rules required by § 40-3-120(2)(a), C.R.S. The following proposed rules are intended to address fuel cost efficiency as they relate the costs recovered through Electric Commodity Adjustment for Public Service and the Energy Cost Adjustment for Black Hills. Both utilities are subject to formal prudency review procedures as established by Commission decision.[8]

33. Proposed paragraph 3863(a) explicitly states the Commission's expectation that electric utilities in Colorado will use economic dispatch of electric generation facilities to minimize fuel costs.

34. Proposed paragraph 3863(b) then ties the Commission's review of generation resource cost efficiency in the utility's Electric Resource Plan (ERP) proceedings—efficiency of

[8] *See* Decision No. C06-1379, issued on December 1, 2006, Proceeding No. 06S-234EG (Public Service) and C22-0138, issued on March 4, 2022, Proceeding No. 21A-0197E (Black Hills).

both new facilities to be acquired and existing generation facilities that will continue to operate—to the establishment of a baseline that can be used to evaluate the prudency of fuel usage in a subsequent cost recovery proceeding. This concept was introduced in a previous Commission rulemaking that was suspended upon the enactment of House Bill 19-1261 and Senate Bill 19-236 requiring the filing of Clean Energy Plans (CEPs) to achieve greenhouse gas emission reductions.[9] For instance, the Commission sought to examine in Proceeding No. 19R-0096E whether electric utilities have sufficient financial incentive to control costs or to operate generation resources to the benefit of customers, particularly since fuel expenditures are pass-through costs recovered directly from ratepayers. The Commission opined that the utilities may be indifferent not only to implementing more efficient ways to operate the existing resources into the future but also to examining whether less expensive alternatives have become available in the marketplace. Accordingly, the Commission sought comments on how Commission should ensure that resources continue to fulfill their expected roles under economic dispatch.[10]

35. Finally, proposed paragraph 3863(c) is intended to support the development and implementation of additional PIMs, as appropriate, to ensure economic dispatch and the minimization of gas commodity fuel costs as contemplated by SB 23-291. The proposed rule further clarifies that the production cost efficiency PIM shall complement the utility's E-GPIM regarding incurred gas commodity fuel costs.

E. Conclusion

36. 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

[9] *See* Decision No. C21-0246, issued on April 23, 2021, Proceeding No. 19R-0096E.
[10] *See* Decision No. C19-0197, issued on February 27, 2019, Proceeding No. 19R-0096E.

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.

37. The Commission 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 Commission deems oral presentations unnecessary.

38. The proposed rules in legislative (*i.e.,* strikeout/underline) format (Attachment A) and final format (Attachments 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-0410E

39. Initial written comments on the proposed rule changes are requested by October 17, 2024. Any person wishing to file comments responding to the initial comments is requested to file such comments by November 1, 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.

40. 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-0410E.

41. 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 October 10, 2024, edition of *The Colorado Register*.

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

DATE	November 5, 2024
TIME:	9 a.m. until no later than 1:00 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

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 October 17, 2024, and that any pre-filed comments responsive to the initial comments be submitted no later than November 1, 2024. The Commission will consider all submissions, whether oral or written. The Commission prefers that comments be filed into this Proceeding using the Commission's E-Filings System at: https://www.dora.state.co.us/pls/efi/EFI.homepage.

5. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING September 18, 2024.

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ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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Commissioners