Decision No. C25-0017

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.

COMMISSION DECISION
ADOPTING RULES

Issued Date: January 10, 2025
Adopted Date: December 30, 2024

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I. BY THE COMMISSION

A. Statement

1. On September 30, 2024, the Colorado Public Utilities Commission issued a 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.

2. By this Decision, the Commission adopts changes to the Electric Rules as 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.

B. Background

3. 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]

4. 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. Section 4 of the bill 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."[2] 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.

5. As explained in the NOPR, the Commission proposed 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 Commission clarified that the introduction of these new provisions was intended as a point from which to continue the conversation begun in the pre-rulemaking in Proceeding No. 23M-0493EG. The Commission also stated that it remained open to continued discussion of these proposed rules as well as additional approaches.

6. In the rules attached to the NOPR, proposed paragraphs 3862(a) through (c) establish a Gas Commodity Fuel Performance Incentive Mechanism or "E-GPIM." The design of the proposed E-GPIM mirrors the Gas Performance Incentive Mechanism, or "GPIM," being

[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(2), C.R.S.

developed for the state's investor-owned gas utilities also pursuant to the requirements from SB 23-291 in Proceeding No. 24R-0192G.

7. Proposed paragraph 3862(a) would require the electric utilities to include an E-GPIM in their rate adjustment mechanism used to recover fuel costs for electricity generation. This rate adjustment is the "ECA," or specifically the Electric Commodity Adjustment for Public Service[3] and the Energy Cost Adjustment for Black Hills.[4]

8. Proposed paragraph 3862(b) would set a deadline for the utilities to file the necessary tariff sheets to introduce a E-GPIM into their ECAs. Proposed paragraph 3862(c) would define the symmetric sharing mechanism that is the centerpiece of the E-GPIM. Proposed paragraph 3862(d) would require that the utility provide workpapers in executable format showing the calculation of the E-GPIM sharing amount included in the ECA. Finally, proposed paragraph 3862(e) states that the Commission may examine the implementation of the E-GPIM in the utility's established prudence review process for the ECA.

9. Proposed Rule 3863 in the rules attached to the NOPR addresses Electricity Production Cost Efficiency and is specifically intended to satisfy the requirement in § 40-3-120(3)(a)(II), C.R.S. 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. 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 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

[3] Public Service Company of Colorado, Colo. PUC No. 8, Sheet Nos. 143 through 143H.
[4] Black Hills Colorado Electric, LLC, Colo. PUC No. 11, Sheet Nos. 61 through 65.

prudency of fuel usage in a subsequent cost recovery proceeding. Proposed paragraph 3863(c) is intended to support the development and implementation of additional incentive mechanisms, 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 incentive mechanism shall complement the utility's E-GPIM regarding incurred gas commodity fuel costs.

10. In response to the NOPR, written comments were filed by Public Service Company of Colorado ("Public Service"), Black Hills Colorado Electric, LLC ("Black Hills"), the Colorado Office of the Utility Consumer Advocate ("UCA"), and the Colorado Energy Consumers ("CEC").

11. Each of the rulemaking participants also appeared at the rulemaking hearing on November 5, 2024.

C. Comments

1. Public Service

12. Public Service filed written comments on October 17, 2024, November 1, 2024, and November 22, 2024.

a. Proposed E-GPIM in Rule 3862

13. With respect to the E-GPIM benchmark in proposed subparagraph 3862(c)(I) in the rules attached to the NOPR, Public Service raises the same objections to the use of a historic baseline for the E-GPIM as it raised with respect to the GPIM for the Gas Cost Adjustment ("GCA") for the gas utilities in Proceeding No. 24R-0192G. In sum, Public Service argues that establishing a baseline upon historical costs from the same quarter of the previous year does not allow the Company to improve its management of fuel costs proactively, as expressly stated in SB 23-291. Public Service further stresses that historical prices are not indicative of future prices,

and in fact have little correlation to future costs, due to market volatility. Public Service instead recommends that the Commission use a current index price benchmark, which would incent the electric utility to employ procurement practices and decisions that result in cost-savings to customers. Public Service proposes rule language to apply a current index baseline derived from daily industry publication, where both daily and monthly index prices for each purchase region would be compared to actual monthly costs.

14. In its comments filed on October 17, 2024, Public Service presents an historical analysis of the Commission's proposed E-GPIM. Public Service concludes that commodity price fluctuations over the past few years (within the 2020-2023 timeframe) reflect enormous swings. For instance, the Winter Storm Uri jump in gas prices would have resulted in a nearly $13 million penalty from that quarter alone. In contrast, the recent gas commodity price reductions in 2023, coming off the price spikes in 2022 stemming from the economic recovery from COVID-19, would have created a nearly $11.9 million award.

15. Public Service also insists that any historical benchmark must be adjusted for inflation during the intervening time. Public Service states that a shift in risk to the utility from ongoing inflation would exacerbate the existing shifting of risk to the utility from a gas fuel incentive mechanism.

16. Consistent with its position regarding the proposed GPIM for the GCA, Public Service also asks that the Commission increase the deadband measure for the ECA from $0.20/Dth to at least $0.50/Dth in subparagraph 3862(c)(III). Public Service notes that this change is consistent with the Recommended Decision issued by Hearing Commissioner Eric Blank in Proceeding No. 24R-0192G. Public Service also seeks clarification that the incentive or penalty applies only to costs (either positive or negative) outside of the deadband.

17. Turning to the E-GPIM sharing amount in subparagraph 3862(c)(III), Public Service asks that the Commission reduce the risk-sharing percentage for the ECA to a level lower than 5 percent – ideally 2 or 3 percent – in order to match more closely several other risk-sharing incentive mechanisms around the country, to better allow for continuous incentives/disincentives to minimize the current gas fuel costs over the course of a year, and to help limit risk exposure to the utility's shareholders.

18. Public Service also seeks clarification that financial hedging, storage, and longer-term fixed price contracts be excluded from the proposed E-GPIM. Public Service warns of an unintended consequence where utilities would spend less and less money on financial products as they would be incentivized to reduce costs as much as possible as compared to the benchmark year(s) or quarter(s), or, on a day-to-day basis, to prioritize price mitigation over power availability and reliability operations.

19. In its written comments filed on November 22, 2024, Public Service asks the Commission to refrain from establishing a specific cap for the E-GPIM in paragraph 3862(c). Public Service argues that all stakeholders would benefit from having more flexibility to set the cap and adjust it, if necessary, on a case-by-case basis and over time as conditions change or as new regulatory frameworks continue to evolve. However, if the Commission decides it wants to include a cap in this rulemaking proceeding, Public Service suggests the cap be reduced to something at or below $5 million a year. Public Service objects to the proposed cap of 40 basis points pre-tax return on the utility's electric rate base, because that cap equates to over $42 million, an amount "far too high for the Company to manage its financial exposure." Public Service further notes that even during the extremely high gas prices in 2021, it was "nowhere near reaching the proposed cap. The fact that the cap would not be reached, even in the face of an extraordinary

event such as Winter Storm Uri, further supports the conclusion that the proposed cap is far too high and should be significantly reduced."

20. Public Service also suggests that the cap be set as a quarterly measure. Public Service explains that a quarterly cap would serve to establish the same maximum penalty or incentive over a twelve-month period but would allow for equal participation of all quarters and provide the utility greater operational flexibility. In contrast, an annual maximum cap on penalties and incentives could swing widely between quarters and create significant earnings volatility.

21. In addition, Public Service asks the Commission to add provisions that would permit a utility to request a force majeure exception to the E-GPIM for good cause shown. Public Service also asks the Commission to adopt a prudence review standard like the prudence review standard as included in the GCA rules. As the Commission has opened this NOPR to review and consider new Electric Rules, Public Service suggests that this is an appropriate time to adopt a similar prudency review standard as in the GCA rules so that these is no question about the appropriate standard of review to determine the prudency of the costs recovered through the ECA. Public Service further asks the Commission to provide adequate time between the finalization of the rules adopted in this Proceeding and the implementation of the new rules so that the utilities' ongoing operations and cost protection plans would not become retroactively effective under a new incentive mechanism.

22. Finally, Public Service asks the Commission to establish a test period for the implementation of any E-GPIM adopted by the Commission in this rulemaking. Public Service explains that interested parties in this Proceeding have had barely one month to evaluate the proposed rules in the NOPR and argues that there are additional issues that have not been discovered with the mechanics of the E-GPIM proposal, which may lead to unintended

consequences. A test period would allow the electric utilities to evaluate a full year of the E-GPIM and could then propose any necessary modifications before it becomes effective. Public Service further suggests that a test period would protect both the utilities and their customers while ensuring that the mechanism will meet the purpose and intent of SB 23-291.

b. Electricity Production Cost Efficiency in Rule 3863

23. With respect to the Electricity Production Cost Efficiency provisions in the proposed rules attached to the NOPR, Public Service argues that Rule 3863 is unnecessary and should not be adopted in this Proceeding. Public Service urges the Commission to focus instead on the proposed E-GPIM to address the intent of SB 23-291. Public Service further states that it would be premature for the Commission to implement such provisions without the proper time required to provide thoughtful analysis and comments.

24. In its comments filed on October 17, 2024, Public Service states that various incentive mechanisms have been instituted many times with respect to the ECA, but an incentive mechanism typically only last a few years before being eliminated. According to Public Service, the Commission has moved the ECA to a pass-through mechanism that currently exists today, recognizing the changing energy landscape and the potential unintended consequences of the failed incentive mechanisms. Public Service further states that the evolution of the ECA has led to a thorough review process that gives the Commission and parties more than sufficient detail to review the Company's fuel costs and the use of its generating resources. Through its experience, the Company has concerns with the proposed provisions related to Rule 3863 since the lessons learned from prior incentive mechanisms still apply.

25. For instance, Public Service states that the rule needs to be substantially clarified on the precise definition of "economic dispatch." Public Service warns that it is possible that the

proposed rule could incentivize operators to take more risk (like maintaining less reserves) and compromise reliability in favor of cost. Public Service also questions the validity of resource planning models to serve as a benchmark for real time operations and the resulting costs. Public Service argues that using ERP models that occur years in advance would be inappropriate to use as a baseline for prudency as they are not in the level of detail, nor do they consider real time system conditions of an evolving electric system. Public Service further concludes that additional production cost efficiency incentive mechanisms would address "a non-existent issue."

c. Incentives for Generation Fuels other than Gas

26. Public Service states that applying an incentive mechanism like the E-GPIM would not be appropriate for other electricity generation fuels due to the difference in timing of acquisition of those fuels. Public Service was also unable to consider alternative incentive mechanisms that could apply to fuels besides natural gas in the short amount of time afforded by this rulemaking.

2. Black Hills

27. Black Hills filed written comments on October 17, 2024, and November 1, 2024.

a. Proposed E-GPIM in Rule 3862

28. Black Hills states that it "has strong reservations with the proposal that the E-GPIM benchmark be established using historic data." Black Hills suggests that if a benchmark is used, it should instead be derived from forward market values. Black Hills argues that the historic benchmark in the NOPR rules "accomplishes little else but to disincentivize utilities from sourcing natural gas for electricity generation, especially utilities – such as Black Hills Colorado Electric – who have proactively shifted away from coal-fired generation in furtherance of greenhouse gas emission targets promulgated by the state legislature and this Commission."

Black Hills also states that the proposed benchmark could disallow recovery of a legitimate and prudently incurred cost of providing service "merely because the market price of gas has increased as compared to the prior calendar year." Black Hills further argues that Colorado utilities have a Fifth Amendment right to a reasonable opportunity to recover their prudent cost of providing service. Black Hills concludes that the proposed E-GPIM fails to protect consumers from volatile swings in commodity prices or improve the management of fuel costs "to no good end," penalizing utilities and their customers with potential credit downgrade risks and higher borrowing costs.

29. Black Hills goes on to state that: "Should the Commission truly wish to develop mechanisms to align the financial incentives of investor-owned utilities with the interests of customers regarding fuel costs, then the Commission must eliminate the current pass-through nature associated with gas costs. The Commission must allow utilities to markup the cost of gas for generation purposes when needed and possess some opportunity for financial gain before any alignment can occur."

30. Black Hills further states that it opposes a framework that does not provide each utility the opportunity or flexibility to address its own unique portfolio attributes in efforts to address SB 23-291 requirements to align the financial incentives of the utility with the interests of the utility's customers regarding incurred fuel costs.

31. Like Public Service, Black Hills asks that the Commission increase the deadband measure for the implementation of an incentive or penalty from $0.20/Dth to $0.50/Dth. Black Hills argues that this modification would trigger the sharing mechanism of the E-GPIM less frequently. Black Hills also asks the Commission to reduce the cap from 40 basis points pre-tax return on the utility's electric rate base to 30 basis points. Black Hills argues that this modification would trigger the sharing mechanism of the E-GPIM less frequently.

b. Electricity Production Cost Efficiency in Rule 3863

32. Black Hills asks that the Commission strike proposed Rule 3863 in its entirety. Black Hills specifically objects to Rule 3863(b) that includes the term "prolonged uneconomic operations." Like Public Service, Black Hills also objects to tying the actual performance of a generation unit to the assumptions used in resource planning proceedings. Black Hills also warns that future participation in organized wholesale markets will complicate any "economic dispatch" of its generation resources. Black Hills concludes: "Imposing an ill- defined additional [incentive mechanism] at this time may frustrate and complicate the utilities' efforts in market exploration."

3. UCA

33. UCA filed written comments on October 17, 2024, and November 1, 2024.

34. UCA generally supports the proposed E-GPIM. UCA also states that it agrees with the modifications to the proposed rules requested by the utilities which were approved by Chairman Blank in his Recommended Decision addressing the similar rules governing the GCA in Proceeding No. 24R-0192G.

35. UCA further states that should the Commission modify the proposed gas rules in Proceeding No. 24R-0192G, UCA supports that any changes made to those rules be incorporated into relevant portions of the electric rules. UCA argues that uniformity is desirable as between the parallel electric rules and gas rules to implement a mechanism to align financial incentives pertaining to fuel costs. UCA further argues that neither Public Service nor Black Hills has provided a compelling basis for there to be divergences between the fuel cost recovery mechanism for the electric utilities to be different than the mechanism for the gas utilities.

4. CEC

36. CEC filed written comments on November 22, 2024.

a. Proposed E-GPIM in Rule 3862

37. CEC opposes the adoption of the E-GPIM in this Proceeding, arguing that Commission should take additional time to evaluate alternative rules better tailored to the unique characteristic of electric utilities, rather than model rules after the GPIM for the gas utilities. CEC explains that, unlike gas utilities which are bound to rely upon gas supplies alone, electric utilities have a substantial degree of control over their resource mix, supply, and dispatch. CEC thus argues that electric utilities enjoy "better optionality in optimizing a mix to ensure reliability of power and keeping costs reasonable for customers."

38. CEC also asks the Commission to consider developing an alternative to the E-GPIM that is modeled after the Energy Cost Adjustment Mechanism ("ECAM") for Rocky Mountain Power ("RMP") in Wyoming. RMP files an annual ECAM application where it requests approval to recover actual energy costs for the preceding calendar year above the net power costs included base rates as set in the prior general rate case. The difference between actual and base net power costs is then subject to an 80/20 sharing band—where RMP's actual net power costs from the prior calendar year exceed base net power costs, RMP is entitled to recover only 80 percent of the ECAM Deferral from ratepayers; conversely, if RMP's actual net power costs from the prior calendar year are below base net power costs, 80 percent of the benefit from that variance is credited back to ratepayers. Structured this way, RMP is incentivized to keep actual net power costs as low as manageable.

39. CEC argues that an ECAM for Colorado would incentivize utilities to use best efforts to keep power costs at the same level as base rates, because they will have to absorb 20 percent of any amount incurred above it but are also assured that if the market is "out of control," they will be able to recover 80 percent of those prudently incurred costs. CEC further explains that

because electric utilities can control their dispatch decisions, the utility can purchase power, reduce curtailments of renewables, or call on demand response resources to affect a reduction in its fuel costs.

40. CEC acknowledges that the adoption of an ECAM for Colorado would be a sweeping change, because it would replace the utilities' ECA as well as its Purchased Capacity Cost Adjustment. CEC notes, however, that an ECAM type mechanism could satisfy both the fuel cost and electricity production cost efficiency aspects of the mandate in § 40-3-120, C.R.S.

b. Electricity Production Cost Efficiency in Rule 3863

41. CEC encourages the Commission to delete Rule 3863 as proposed in the NOPR. CEC argues that the rule is imprecise and would create more confusion in an area which is already a source of disagreement in Commission proceedings. CEC agrees that utilities must take accountability for "prolonged uneconomic operations," but the term in the proposed rule is undefined and the framework surrounding related disallowances necessitates more robust and thoughtful development. CEC also agrees with the premise of the proposed rule that the assumptions used in resource planning should inform the evaluation of a generating unit's actual performance. However, CEC cautions that the nuances of how best to achieve this objective require more deliberation, more input from more stakeholders, and more data collection and review.

D. Discussion, Findings, and Conclusions

42. The Commission promulgates rules under its legislative function that are necessary and proper for the proper administration and enforcement of the Public Utilities Law (*i.e.*, Articles 1 through 7 of Title 40 of the Colorado Revised Statutes) and within the Commission's broad Constitutional and statutory authority to regulate utilities. *See* Article XXV of the Colorado Constitution and § 40-2-108(1), C.R.S. In the regulation of public utilities, the Commission has

broad authority unless and until the General Assembly expressly acts to restrict the Commission's authority.

43. Consistent with the discussion below, we adopt the following modifications to the Electric Rules.

1. Electric Generation Fuels Other than Natural Gas

44. 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.

45. The Commission solicited comments through the NOPR on whether it should examine the development of additional symmetrical incentive mechanisms regarding incurred costs for other fuels used to generate electricity such as coal.

46. We will not adopt rules requiring incentive mechanisms that apply to electric generation fuels besides natural gas. We agree with Public Service that applying an incentive mechanism like the E-GPIM proposed in the NOPR would not be appropriate for other fuels due to the difference in the way such fuels are purchased, stored, and used. We also agree with the utilities that there was insufficient time in this rulemaking to consider additions or alternatives to the E-GPIM.

2. Electricity Production Cost Efficiency

47. We will not adopt Rule 3863 as proposed in the NOPR. While we see potential merit in additional incentive mechanisms that promote the economic dispatch of generation resources and that help to ensure that generation resources are used in a way that avoids costly

dispatch selections by the utilities, these concepts require further development than can be accomplished in this Proceeding.

3. Gas Commodity Fuel Performance Incentive Mechanism

48. Based upon our review of the utilities' comments and the cautionary advice from CEC, and in accordance with the discussion below regarding Rule 3861, we are sympathetic to their concerns about unintended consequences. We further see merit in adopting an incentive mechanism on a slower, more deliberate schedule. This revised approach to introducing the incentive mechanism is directly supported by SB 23-291, which requires the Commission to tailor the mechanisms to apply to different utilities based on a utility's size or ability to implement the mechanisms, as well as the comments offered throughout this Proceeding.

49. Instead of the provisions establishing a specific E-GPIM as proposed in the NOPR, we adopt paragraph 3861(a) to require the electric utilities to implement a symmetric incentive mechanism that shares the risk of natural gas commodity costs between the utility and its customers in their rate adjustment filings used for the recovery of purchased fuel costs for electricity production in accordance with SB 23-291. As explained above, this rate adjustment is the Electric Commodity Adjustment for Public Service and the Energy Cost Adjustment for Black Hills.

50. We also adopt the provisions in paragraph 3861(b) where each electric utility files an application to modify its ECA tariff sheets to implement the symmetric incentive mechanism that is suited to the specific characteristics of that utility. The rule requires the utilities to file an application to include the incentive mechanism within their ECA tariff sheets within 60 days of the effective date of these modified rules. Once established, the incentive mechanism shall be implemented through the utility's ECA in accordance with the utility's ECA tariff sheets in effect.

Modifications to an incentive mechanism, once initially established, will also be accomplished by an application filing separate from the normal implementation of the ECA.

51. Finally, paragraph 3861(c) affirms that the implementation of the incentive mechanism may be examined in the utility's prudence reviews already used for its ECA. Both utilities are subject to formal prudency review procedures as established by Commission decision.[5] However, we conclude that it is unnecessary to adopt a prudency review standard in these rules, as requested by Public Service. The modifications to the Commission's Electric Rules contemplated in this rulemaking were never intended to encompass a comprehensive assessment of the ECA as a cost recovery mechanism.

52. For the same reasons we do not adopt specific provisions to implement an E-GPIM as proposed in the NOPR, we also decline to endorse the adoption of rules that would implement a modified version of the ECAM used for RMP in Wyoming, as suggested by CEC. We agree with CEC that the adoption of an ECAM for Colorado would be a sweeping change. The potential impacts of such changes have not been fully examined in this Proceeding; hence, it would be premature to adopt a rule requiring the implementation of this alternative incentive mechanism.

II. ORDER

A. The Commission Orders That:

1. The Rules Regulating Electric Utilities in 4 *Code of Colorado Regulations* 723-3, attached to this Decision in legislative/strikeout format as Attachment A, and in final format as Attachment B, are adopted, and are available in the Commission's Electronic Filing System at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=24R-0410E

[5] *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).

2. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted.

3. A copy of the final, adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State

4. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Decision.

5. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING December 30, 2024.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners