Decision No. R24-0682

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.

RECOMMENDED DECISION OF HEARING COMMISSIONER ADOPTING RULES

Issued Date: September 23, 2024

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I. STATEMENT

1. On April 30, 2024, the Commission issued a Notice of Proposed Rulemaking ("NOPR") through Decision No. C24-0278 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.

2. This Decision adopts amendments and additions to the Commission Rules governing Gas Cost Adjustments ("GCA" or "GCA Rules"), set forth in the Gas Rules at 4 CCR 723-4-4600 through 4610, for the purpose of protecting Colorado gas utility customers while also improving the gas utilities' management of fuel cost in accordance with § 40-3-120, C.R.S. The adopted rules require the continued implementation of Gas Price Risk Management Plans ("GPRMPs") and 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. Specifically, the adopted amendments to the GCA Rules replace the requirements for the Gas Performance Incentive Mechanism ("GPIM") established in Proceeding No. 21R-0314G with a new incentive mechanism as required by SB 23-291.

II. BACKGROUND

A. Senate Bill 23-291

3. As explained in the NOPR, 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.

4. Section 4 of SB 23-291 required each investor-owned gas utility to file with the Commission, on or before November 1, 2023, a GPRMP to address the volatility of fuel costs recovered from the utility's customers pursuant to the utility's GCA filings.[1] A GPRMP was established for each of Colorado's four investor-owned gas utilities through utility application proceedings that concluded in November 2023.[2]

5. Section 4 also requires the Commission to adopt rules, on or before January 1, 2025, to establish, in addition to the GPRMPs, "mechanisms that align an investor-owned utility's financial incentives with the financial interests of its customers regarding incurred fuel costs."[3]

B. Modifications to the GCA Rules Presented in the NOPR

6. The proposed revisions to the GCA Rules set forth in the NOPR comprise two primary elements: proposed paragraph 4603(g) incorporates the utilities GPRMPs as a permanent feature of gas cost recovery through the GCA, while proposed Rule 4607 establishes a new mechanism that shares as a financial incentive a portion of decreases and increases in gas commodity prices reflected in the utilities' GCAs.

7. Proposed paragraph 4603(g) is based on the language in § 40-3-120(1), C.R.S., such that the calculation of the GCA is subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs. Costs above the maximum cap are recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs. Collections at the minimum threshold are recorded in a reserve

[1] § 40-3-120(1), C.R.S.

[2] *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.

[3] § 40-3-120(2), C.R.S.

fund to offset any deferred balance of prudently incurred costs above the maximum cap. The rule essentially defines the essence of a utility's GRPMP, and the rule is implemented through utility-specific provisions in their GCA tariff sheets.

8. Proposed Rule 4607 defines the new financial incentive mechanism—a modified GPIM—to align the utility's financial incentives with the financial interests of customers as also required by SB 23-291. In essence, the proposed mechanism calculates the difference in gas costs between a recently concluded quarter and the same three months in the prior year, splitting a portion of the difference, subject to a deadband, either as a cost born by the utility's shareholders when there is an increase in gas costs or as a share of the savings in the form of earnings for the utility's shareholders. The proposed rule outlines a general structure for the modified GPIM. Certain other proposed rules, such as new definitions in Rule 4601, support the provisions set forth in proposed Rule 4607.

C. Procedural History

9. The Commission discussed the opening of this Proceeding at its weekly business meeting on April 3, 2024. At that same weekly meeting, the Commission closed Proceeding No. 23M-0493EG, the precursor proceeding conducted prior to this rulemaking. The NOPR was then issued on April 30, 2024. The NOPR designated Eric Blank as Hearing Commissioner pursuant to § 40-6-101(2)(a), C.R.S.

10. In accordance with the suggested filing deadlines within the NOPR, initial written comments addressing the proposed revisions to the GCA Rules were submitted by Colorado Natural Gas, Inc. ("CNG"), Black Hills Colorado Gas, Inc. ("Black Hills"), Atmos Energy

Corporation ("Atmos"), Public Service Company of Colorado ("Public Service"), and the Colorado Office of the Utility Consumer Advocate ("UCA").

11. Written comments responsive to the initial comments were later filed by UCA, Atmos, and Public Service.

12. The Hearing Commissioner held a public hearing on the proposed rules July 11, 2024.

13. Post-hearing comments were filed by Black Hills, Atmos, and Public Service.

III. DISCUSSION, FINDINGS, AND CONCLUSIONS

14. 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.

15. In rendering this Decision, the Hearing Commissioner has carefully reviewed and considered all participant comments in this Proceeding, whether filed in writing or provided orally at the July 11, 2024, public comment hearing, even if this Decision does not specifically address every comment made.

A. Modified GPIM Requirements per SB 23-291

16. Atmos, Black Hills, and Public Service each strongly objects to the implementation of the proposed GPIM as set forth in the NOPR.[4] Atmos and Black Hills ask that the Commission instead find that rule 4607 currently in the GCA Rules ("Existing GPIM Rule") satisfies the requirements of SB 23-291 and allow individual utility GPIM filings to move forward under those terms established in Proceeding No. 21R-0314G.[5] Public Service does not oppose the implementation of the Existing GPIM Rule, but it also puts forward an alternative to the GPIM set forth in the NOPR (*i.e.*, Public Service's "Primary Proposal").

17. Atmos argues that the proposed GPIM creates arbitrary outcomes for both the utilities and their customers. Atmos opposes a GPIM benchmark based on preceding GCA filings, stating that the utility makes gas purchasing decisions based on current and expected market conditions and not based on historical periods.[6] Atmos also argues that nothing in SB 23-291 requires the Commission to adopt a mechanism such as proposed in the NOPR, which Atmos states would fail to satisfy the requirements in SB 23-291 both to protect customers and to improve the utility's management of fuel costs. Atmos further states that disallowing recovery of a legitimate and prudently incurred cost of providing service merely because the market price of gas has increased would be confiscatory and contrary to a utility's right to a reasonable opportunity to recover its cost of providing service. Atmos also contends that § 40-3-120(2), C.R.S., as enacted by SB 23-291 did not modify a utility's fundamental right to a reasonable opportunity to recover its cost of providing service to customers in Colorado.[7]

[4] CNG supports the proposed exclusion of CNG from the proposed requirements for the GPIM as proposed in the NOPR. CNG Initial Comments, p. 2.
[5] Atmos Post-Hearing Comments, p 3.
[6] Atmos Initial Comments, p. 10.
[7] Atmos Post-Hearing Comments, p. 2.

18. Black Hills likewise argues that the proposed GPIM is wholly inappropriate and does nothing to manage fuel costs but is instead "simply a mechanism to punish gas utilities."[8] Black Hills suggests that the Commission should not "rush through a rulemaking" after spending almost two years developing the Existing GPIM Rule. Black Hills concludes that if the Commission seeks to develop mechanisms to align the financial incentives of the utilities with the interests of customers regarding fuel costs, the pass-through nature of the GCA should be abandoned and the Commission instead should allow utilities to markup the cost of gas and actually have some opportunity for financial gain before any alignment can occur.[9]

19. Echoing Atmos and Black Hills, Public Service argues that the modified GPIM in the NOPR would not meet the intent of SB 23-291 of protecting customers and improving the utility's management of fuel costs due primarily to its reliance on using historical gas commodity costs as the relevant price benchmark. Public Service notes, for instance, that had the revised GPIM been in place prior to Storm Uri, Colorado utilities would have incurred significant penalties. Yet following Storm Uri, the utilities would have received significant gains due to the drop in gas commodity market prices without "having done anything to influence or manage the price change."[10] Public Service further notes that such losses and gains increase risk and volatility, contrary to the intent of SB 23-291.

20. Public Service's Primary Proposal replaces the use of an historical baseline with baseline calculations using current index prices, which Public Service argues would help further incent cost-minimizing purchasing behaviors by the utilities to the benefit of their customers.[11]

[8] Black Hills Post-Hearing Comments, p. 2
[9] Black Hills Post-Hearing Comments, p. 4.
[10] Public Service Initial Comments, pp. 13-14.
[11] Public Service Initial Comments, pp. 26-27.

Public Service stresses that its Primary Proposal does not involve forward looking assumptions, but instead relies on current market prices as the benchmark, comparing actual monthly costs to published monthly prices reported in industry trade publications. Public Service argues that by comparing actual costs to "transparent market prices," its alternative mechanism would better measure the effectiveness of the utility's fuel procurement practices by comparing prices paid by the utility to prices paid by all other market participants. According to Public Service, its alternative approach would give the utility an opportunity to earn an incentive by beating the market or charge a penalty when the utility underperforms. For the sake of simplicity, Public Service proposes to use monthly index prices for each gas purchasing region when comparing actual monthly costs.[12] Public Service further demonstrates how its Primary Proposal would have functioned in the eight previous heating seasons. Public Service concludes that its proposed alternative approach results in a modest penalty or incentive in most years.[13]

21. While Black Hills "does not detract" from the Public Service's call for use of published index prices at purchase locations as a means of establishing the foundation for a market benchmark price, it does not agree that Public Service's Primary Proposal should become a Commission rule to be implemented by each gas utility. Black Hills states that while the proposal may work for some utilities, it may not appropriately work for all utilities. For instance, Black Hills states that a published monthly index does not take into account several factors that may influence the actual purchase cost, or market value, of gas commodity supply at any given time and location, such as liquidity, purchasing power, and supply and demand, among other factors.[14]

[12] Public Service Initial Comments, p. 29.
[13] Public Service Initial Comments, pp. 29-31.
[14] Black Hills Post-Hearing Comments, p. 12.

22. In its responsive written comments, UCA acknowledges that the utilities see no reason to modify the Existing GPIM Rule. However, UCA states that it does not believe that the General Assembly intended the Commission to retain the Existing GPIM Rule but instead expected the rule to be modified in a manner that is consistent with what the Commission proposed in the NOPR.[15]

23. Black Hills counters that there is no way the General Assembly could have intended to undo the Existing GPIM Rule because it was never implemented to see how it would work. Black Hills further states that the Existing GPIM Rule already contemplates all the same factors referenced in SB 23-291.[16]

24. The Hearing Commissioner agrees with UCA regarding the General Assembly's expectation that the Commission revisit the GCA Rules notwithstanding its recent adoption of the Existing GPIM Rule. Section 4 of SB 23-291 requires the gas utilities to implement a GPRMP subject to a financial incentive mechanism.

25. The adoption of rules that integrate the GPRMPs into the Commission's GCA framework satisfies much of the requirement in SB 23-291 that the Commission protect Colorado gas utility customers while also improving the gas utilities' management of fuel cost. The GPRMPs, in combination with other actions taken by the utilities in accordance with their Gas Purchase Plans ("GPPs") pursuant to Rules 4605 and 4606 and with their financial hedging strategies addressed separately by application, will serve to reduce the volatility of fuel costs passed on to customers. The Hearing Commission further adopts the modified GPIM, with certain revisions addressed by this Decision, to further align the investor-owned utility's financial

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[15] UCA Response Comments, pp. 1 and 4.
[16] Black Hills Post-Hearing Comments, p. 8.

incentives with the financial interests of its customers regarding incurred fuel costs beyond what is achieved through the existing GCA framework and the recently established GPRMPs for each utility. The modified GPIM, as developed in Rule 4607, is the approach that is most suited to align the Commission's goals with the requirements of SB 23-291.

B. Changes to the GCA Rules

1. Rule 4600 – Overview and Purpose

26. Rule 4600 is modified in the NOPR to expand the stated purpose of the GCA Rules in accordance with SB 23-291 and to remove references to GPIM applications associated with the Existing GPIM Rule.

27. Upon consideration of the comments filed in this Proceeding and the incorporation within the Commission's GCA framework of both the GPRMPs and the modified GPIM, the Hearing Commissioner adopts similar modifications to Rule 4600 to address these key elements of SB 23-291 in the statement of the purpose of the GCA Rules.

2. Rule 4601 – Definitions

28. The NOPR proposed to add two new defined terms used in the modified GPIM: "Actual Total Gas Cost" in proposed paragraph 4601(b) and "Actual Total Gas Quantity" in proposed paragraph 4601(c).

29. In its initial comments, Public Service seeks clarification that the phrase "appropriate adjustments" in definition of Actual Total Gas Costs, is intended to accommodate exclusions of certain expenditures so that the GPIM complements the gas utility's efforts to smooth and reduce the volatility of fuel costs passed on to customers. Public Service likewise asks that the Commission modify the definition of Actual Total Gas Quantity to exclude storage injections and

withdrawals, financial hedging, quantities subject to longer-term fixed price contracts and other nonstandard costs. Public Service suggest that these modifications to the defined terms that support the modified GPIM prevent perverse incentives to deploying tools that help mitigate the volatility of fuel prices.[17]

30. Atmos states in its initial comments that it is appropriate for Actual Total Gas Costs to exclude upstream transportation costs. However, Atmos wants the Commission to affirm that Actual Total Gas Costs as defined in the NOPR would include storage and hedging costs.[18] Atmos further suggests that instead of using the word "Actual" in the two new definitions for the GCA Rules, the acronym "GPIM" be used instead to avoid confusion with other terms in the Gas Rules.

31. In response to Atmos' comments, Public Service repeats its suggestion that storage costs or hedging costs should not be included in the definition of Actual Total Gas Costs.[19] Public Service states, for example, that inclusion of storage costs may incent utilities to pursue lower costs at the risk of jeopardizing reliability, contrary to the public interest. Likewise, the inclusion of hedging costs could cause utilities to spend less money on financial products in the name of cost reduction, exposing customers to greater price volatility in the future. Public Service also notes that hedging programs are generally reviewed and approved by the Commission as stand-alone programs independent of the GCA framework.

32. The Hearing Commissioner adopts revisions to the definitions of "Actual Total Gas Cost" and "Actual Total Gas Quantity" based on the comments filed by the utilities. As explained elsewhere in this Decision, it is necessary for certain details of the GPIM to be designed relative to the specific gas supply arrangements and options for each utility and to the different geographic

[17] Public Service Initial Comments, pp. 15-20.
[18] Atmos Initial Comments, p. 8.
[19] Public Service Response Comments, pp. 6-8.

areas that correspond to separate GCAs or purchasing regions within a utility's service area. Those details will best be considered in follow-on application proceedings that introduce the GPIM within the utility's GCA tariff sheets consistent with the revisions to rule 4607 as discussed below. Accordingly, the defined terms related to the GPIM are more general than as proposed in the NOPR and are further tied to the utility's GCA tariff sheets. The Hearing Commissioner further agrees with Atmos that "Actual" should be modified in both definitions; therefore, the new defined terms within the GCA Rules shall be "GPIM Total Gas Costs" and "GPIM Total Gas Quantities."

33. In addition to those revisions, the Hearing Commissioner concludes that the GPRMP should also be identified as a defined term within the GCA Rules. The Hearing Commissioner further refines the definition of the GPIM consistent with the modifications to Rule 4607 discussed below. The definitions required for the Existing GPIM Rule are further removed.

3. Rule 4602 – Schedule for Filings by Utilities

a. Gas Price Risk Management Plan

34. In the rules attached to the NOPR, proposed paragraph 4602(f) requires the utility's GCA to include a GPRMP 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 GPRMP must be accomplished through an application proceeding separate from a GCA filing.

35. The Hearing Commissioner adopts paragraph 4602(f) in the modified GCA Rules. This new provision in rule 4602 is further consistent with the adoption of paragraph 4603(g), as explained below.

36. In its initial comments, Black Hills notes that the rule mistakenly uses the term "gas risk management plan" instead of GPRMP. The error is corrected in the modified GCA Rules attached to this Decision.

b. Small Utility Exemption from GPIM Requirements

37. Proposed paragraph 4602(g) in the NOPR exempts utilities with fewer than 50,000 full-service customers from the GPIM requirements.

38. CNG states that it fully supports the Commission's proposal to exclude utilities with less than 50,000 customers from the GPIM.[20]

39. The Hearing Commissioner finds good cause to preserve the GPIM exemption for the smallest of the state's gas utilities.

c. Utility-Specific GPIM Applications

40. Proposed paragraph 4602(h) in the NOPR 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 in this Proceeding.

41. In its initial comments, Atmos argues that it is not appropriate to litigate GPIMs in quarterly GCA filings. Atmos suggests that each utility instead should file an application to establish its GPIM and that the rule should specify a filing date for such applications following the effective date of the GCA Rules adopted in this Proceeding. Atmos further suggests that a GPIM should be crafted for each of the utility's GCA areas based on the specific gas supply arrangements and options for those different geographic areas.[21]

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[20] CNG Initial Comments, p. 2.
[21] Atmos Initial Comments, p. 8.

42. Black Hills similarly argues that the one-sized fits all approach in proposed Rule 4607 fails to "tailor the mechanisms to apply to different utilities based on a utility's size or ability to implement the mechanisms" as required by SB 23-291. Black Hill argues that the only way to ensure that the mechanisms are appropriately tailored is to retain the Existing GPIM Rule or specifically carve out the nuances associated with each utility based on its size. Black Hills notes that the Existing GPIM Rule already provides the framework that allows for each utility to file an application for Commission approval of a GPIM, where that application would be tailored to each utility's specific size and abilities.[22] Therefore, consistent with Atmos' position, Black Hills states that each utility should be provided with the flexibility to file an application that is tailored to its business, customer base, geographic purchase requirements and gas supply challenges.[23]

43. In its post-hearing comments, Public Service also observes that the filed comments underscore differences amongst the utilities. Public Service this also suggests that each utility submit a GPIM application for Commission approval prior to implementation.[24]

44. The Hearing Commissioner agrees with the utilities that it is necessary to establish certain details of the GPIM for each utility based on its specific characteristics. However, each utility must adhere to basic framework for a GPIM as a rule-based framework is contemplated by Section 4 of SB 23-291. Paragraph 4602(h) therefore requires the utilities to file an application to include a GPIM within their GCA tariff sheets pursuant to Rule 4607 within 60 days of the effective date of these modified GCA Rules. Once established, the GPIM shall be implemented through the utility's GCA in accordance with the utility's GCA tariff sheets in effect.

[22] Black Hills Post-Hearing Comments, pp. 7-8.
[23] Black Hills Post-Hearing Comments, p. 3.
[24] Public Service Post-Hearing Comments, p. 5.

Modifications to a GPIM once initially established will also be accomplished by an Application filing separate from the normal implementation of the GCA.

45. Consistent with the proposed rule changes in the NOPR, the Hearing Commissioner also removes from Rule 4602 the legacy filing requirements that were intended to support the Existing GPIM Rule.

4. Rule 4603 – Gas Cost Adjustment

a. Asymmetric Interest

46. Black Hills notes in its initial comments that the GPRMP in paragraph 4603(g) and the GPIM sharing amounts in proposed in Rule 4607 may result in a utility's GCA deferred balance being partially subject to asymmetric interest and partially subject to symmetric interest.[25] Black Hills suggests that if the net interest in Account 191 is positive, it should be included in the calculation of deferred gas costs.

47. In its initial comments, Atmos provides a summary of the Commission's promulgation of GCA Rules including the history of the specific provisions that address the application of interest to deferred balance amounts. Atmos notes that when the GCA Rules were initially crafted in more-or-less their current form, the Commission held that deferred costs for net over-recoveries shall include interest, but that net under-recoveries shall not, finding that "asymmetrical treatment of interest" was warranted because utilities have "some control over these costs through additional GCA filings" while customers have "no recourse if the GCA rates cause an over-recovery."[26] Atmos goes on to state that the Commission retained the asymmetric

[25] Black Hills Initial Comments, p. 6.

[26] Atmos Initial Comments, pp. 16-17, citing Decision No. C97-376, issued April 8, 1997, in Proceeding No. 96R-089G.

application of interest in its 2005 rulemaking because it represented "one of the few incentives in the GCA rules that causes utilities to strive accurately to match gas purchase and resale prices."[27]

48. The Hearing Commissioner declines to make any modifications to the general asymmetric approach to applying interest to a utility's GCA deferred balance. This well-established feature of the Commission's GCA Rules will remain, and its continued presence has been factored into the adoption of the modified GCA Rules by this Decision.

b. Financial Hedging

49. Modifications to paragraph 4603(e) in the rules attached to the NOPR clarify that the costs associated financial gas commodity hedging may recovered through a utility's GCA if such hedging is allowed by tariffs or by Commission decision.

50. The Hearing Commissioner finds good cause to adopt these uncontested revisions to paragraph 4603(e).

c. GPRMP Requirements

51. As explained in the NOPR, proposed paragraph 4603(g) requires the utility's GCA to be subject to the principal requirements of GPRMP as set forth in SB 23-291. The proposed rule further requires that the GPRMP 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.

52. The Hearing Commissioner adopts the addition of paragraph 4603(g) within the GCA Rules. The utility's continual implementation of its GPRMP serves to satisfy the requirement in SB 23-291 that modified GCA Rules protect Colorado gas utility customers while also improving the gas utilities' management of fuel cost.

[27] Atmos Initial Comments, pp. 16-17, citing Decision Nos. R05-0523, issued May 6, 2005, in Proceeding No. 03R-0520G.

5. Rule 4604 – Contents of GCA Filings

a. GPRMP and GPIM Information in GCA Filings

53. Proposed paragraph 4604(d) in the rules attached to the NOPR requires the utility's GCA filing to include information on the utility's GPRMP and 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.

54. In its post-hearing comments, Public Service suggests that the Commission replace the phrase "GPIM performance results" in paragraph 4604(d) with "GPIM sharing amounts."[28] Public Service further proposes the addition of paragraph 4604(k) to require an Attachment 10 to the utility's GCA filing, where the new attachment would detail the calculation of GPIM sharing amounts.[29]

55. The Hearing Commissioner adopts the modifications to paragraph 4604(d) consistent with the rule language proposed in the NOPR and Public Service's suggested revision. The Hearing Commissioner further adopts Public Service's recommendation to require a specific attachment to the utility's GCA filing (*i.e.*, GCA attachment No. 10) that would detail the calculation of the GPIM sharing amounts. With this addition, the data requirements proposed in the NOPR for GCA attachment A related to the GPIM are moved to the new additional attachment devoted to the GPIM in paragraph 4604(k).

b. GCAs Billed to Customers

56. Subparagraph 4604(g)(II) as proposed in the NOPR 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 GPRMP and GPIM.

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[28] Public Service Post-Hearing Comments, Supplemental Bluelines, p. 7.
[29] Public Service Post-Hearing Comments, Supplemental Bluelines, p. 8.

57. The Hearing Commissioner adopts the modifications of subparagraph 4604(g)(II) consistent with the rule language proposed in the NOPR.

6. Rule 4607 – Gas Performance Incentive Mechanism

a. Adoption of GPIM with Modifications

58. Proposed paragraph 4607(a) in the rules attached to the NOPR sets forth the new symmetric sharing mechanism contemplated in § 40-3-120(2), C.R.S., replacing most of Rule 4607 as adopted in Proceeding No. 21R-0314G.

59. 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 the NOPR) 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. In essence, 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), where 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).

60. The Hearing Commissioner finds that GPIM framework defined by Rule 4607 reasonably aligns the investor-owned utility's financial incentives with the financial interests of its customers who pay the GCA when further adjusted in the specific areas addressed below. The GPIM framework established by this Decision is most suited to satisfying the requirements of SB 23-291 when also implemented with the GPRMPs and the majority of the existing provisions in the Commission's GCA Rules that will remain without modification.

b. GCA Tariff Sheets to Implement the PIM

61. As explained above, paragraph 4602(h) as adopted by this Decision requires the utilities to file an application to include a GPIM within their GCA tariff sheets pursuant to Rule 4607 within 60 days of the effective date of these modified GCA Rules.

62. Consistent with that approach for launching the GPIM, the introductory paragraph to Rule 4607 shall be modified to reiterate that the implementation of the GPIM shall be done by each utility, as applicable, consistent with the provisions for the GPIM within the utility's GCA tariff sheets.

c. GPIM for Each GCA Division or Rate Area

63. Atmos and Black argue that a GPIM should be crafted for each of a utility's separate GCA rate areas based on the specific gas supply arrangements and options for those different

geographic areas.[30] Public Service similarly argues that a GPIM should be establish for separate "purchase regions" as identified in its Gas Purchase Plan ("GPP").[31]

64. The Hearing Commissioner agrees with the utilities that separate GPIMs are necessary for each GCA rate area or purchase region due to the differences in incurred commodity gas costs. The introductory paragraph to Rule 4607 is therefore modified to specify that a GPIM shall be established, as necessary, for each GCA rate area served by the utility or by separate purchase regions, as applicable.

d. GCA Rate Area/Division Exclusions

65. Atmos argues that two of its three GCA divisions have fewer than 50,000 full-service customers and should also be excluded from GPIM requirements due to the small size of these distinct areas.[32]

66. The Hearing Commissioner agrees that GCA rate areas with fewer than 50,000 full-service customers should be excluded from GPIM requirements just as utilities with fewer than 50,000 full-service customers are also excluded from GPIM requirements pursuant to paragraph 4602(g).

e. Adjustments for General Price Information

67. Public Service suggests that differences in the price levels (*i.e.*, the historic price and the price in the last recently completed quarter) be adjusted for "the mere existence of inflation" during the intervening time period.[33] Public Service specifically recommends that the

[30] Atmos Initial Comments, p. 8. Black Hills Post-Hearing Comments, pp. 7-8.
[31] Public Service Initial Comments, pp. 28-29.
[32] Atmos Response Comments, p. 5.
[33] Public Service Initial Comments, p. 34.

inflation adjustment be accomplished using the U.S. Consumer Price Index for all urban customers as maintained by the U.S. Bureau of Labor Statistics.

68. The Hearing Commissioner declines to adopt Public Service's requested inflation modification to the GPIM proposed in the NOPR. The primary means of aligning the utility's financial experience to the customer's experience in paying the GCA is by basing the negative or positive sharing amount on the recently concluded quarter's GCA commodity costs and on the costs in the same quarter in the prior year. Adjustments for general inflation would weaken such alignment and would not be reasonable given the other adjustments to the GPIM adopted by this Decision.

f. Four Year Average for Previous Quarter Price Benchmark

69. Public Service suggests that the historic GPIM price benchmark represent an average over the previous four years instead of the price level in the immediately preceding historic period. Public Service explains that the average will smooth out some of the volatility of the gas commodity market and clarifies that the averaging should also include the adjustments for inflation (as discussed immediately above).[34]

70. The Hearing Commissioner again declines to adopt Public Service's requested modification to the GPIM proposed in the NOPR. The use of a four-year average would weaken the alignment sought by the GPIM between the utility and its customers with respect to gas commodity costs and would not be reasonable given the other adjustments to the GPIM as adopted by this Decision.

[34] Public Service Initial Comments, p. 35.

g. GPIM Sharing Amount

71. Public Service seeks a reduction in the GPIM sharing amount from five percent as proposed in the NOPR in subparagraph 4607(a)(III) to two or three percent. Public Service argues that the lower sharing percentages "more closely match several other risk-sharing incentive mechanisms around the country" and help limit risk exposure to the utilities, such as impacts on authorized rates of return.[35] Public Service further argues that lower percentages are reasonable in relationship to the overall cap when extreme volatility is considered, such as the price spike associated with Storm Uri. Public Service states that a five percent risk-sharing percentage with the modified GPIM in place prior to Storm Uri would have led it to reach the maximum penalty cap in the first quarter of that year, "rendering any impacts that a mechanism could have on the Company's purchasing behaviors largely moot."[36]

72. Black Hills states that, to the extent the Commission decides a sharing percentage is required, the Company supports Public Service's proposal to reduce the risk sharing percentage to three percent.[37]

73. The Hearing Commissioner agrees with Public Service and Black Hills that a reduction in the sharing percentage is warranted based on a review of the information presented in the utilities' comments. The sharing amount is therefore reduced from five percent to four percent as set forth in paragraph 4607(c).

h. Price Deadband

74. Public Service suggests that the deadband around the difference in prices in subparagraph should be widened from \$0.20/Dth to at least \$0.50/Dth. Public Service argues that

[35] Public Service Initial Comments, p. 36.
[36] Public Service Initial Comments, p. 37.
[37] Black Hills Post-Hearing Comments, p. 13.

a deadband of ± \$0.50/Dth roughly represents the 25^{th} percentile of changes in prices over the recent historical period.[38] Public Service states that a \$0.50/Dth amount translates to roughly \$3.00 per month when compared to average annual usage of about 749 therms, or just about five percent of an average monthly residential bill.

75. Black Hills supports the implementation of a deadband, provided that each utility is afforded the flexibility to account for their unique purchase locations and market conditions. If the Commission decides that a deadband is required, Black Hills supports Public Service's proposal to increase the deadband to at least \$0.50/Dth.[39]

76. The Hearing Commission agrees that the deadband around the difference between the GPIM benchmark gas rate and the GPIM actual gas rate should be increased to \$0.50/Dth. The analysis presented by Public Service in its comments supports this change to rule presented in the NOPR and adopted as subparagraph 4607(c)(I).

i. Maximum Sharing Amount

77. Public Service suggests that the Commission remove references to a specific cap on the maximum "penalty amount" in the GPIM provisions within the GCA Rules. Public Service argues that the Commission and the utilities would benefit from having more flexibility to set the cap and adjust it, if necessary, over time as conditions change or as new regulatory frameworks evolve.[40] Public Service further argues that it will be more administratively efficient for the cap to be established and then modified over time through utility filings instead of through additional rulemakings.

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[38] Public Service Initial Comments, p. 38.
[39] Black Hills Post-Hearing Comments, p. 13.
[40] Public Service Initial Comments, p. 33.

78. If the Commission decides to adopt a specific cap established by Rule, Public Service recommends a reduction "to something at or below $5 million"[41] or, instead, 2.5 basis points applied to the utility's rate base on a quarterly basis, as opposed to the 40 basis points suggested in subparagraph 4607(a)(III)(B) in the rules attached to the NOPR.[42] Public Service states that this lower proposed cap still scales relative to a utility's size and allows for "reasonably balanced incentives and penalties." Likewise, in its post-hearing comments, Public Service explains that with gas commodity prices recently settling at approximately $3.00/Dth, the asymmetric nature of gas prices causes a "resulting reality that penalties may be limitless, while incentives would be limited."[43] Public Service thus states it is important for the Commission to retain a symmetrical approach when establishing the cap.

79. Black Hills supports Public Service's proposal to limit the cap to 2.5 basis points.[44]

80. Atmos argues that if a cap on the GPIM cost sharing is going to be established using a basis point reduction to the pre-tax return on rate base, it should solely be to the equity share of the capital structure used to set the pre-tax return on rate base, rather than the overall weighted average cost of capital or rate of return on rate base.[45]

81. Black Hills supports Atmos's proposal that if a cap on the GPIM cost share is going to be established using a basis point reduction to the pre-tax return on rate base, it should solely be to the equity share of the capital structure used to set the pre-tax return on rate base, rather than the overall weighted average cost of capital or rate of return on rate base.[46]

[41] Public Service Initial Comments, p. 33.
[42] Public Service Post-Hearing Comments, p. 6 and Attachment A, p. 11.
[43] Public Service Post-Hearing Comments, p. 6.
[44] Black Hills Post-Hearing Comments, p. 13.
[45] Atmos Initial Comments, p. 10.
[46] Black Hills Post-Hearing Comments, p. 13.

82. The Hearing Commissioner declines to adopt Public Service's request that the overall cap on GPIM costs to the utility be established for each utility in its GPIM application instead of by rule. However, the Hearing Commissioner agrees that it is reasonable to reduce the GPIM cap set forth in the GCA Rules by lowering the basis points applied to the utility's rate base. As opposed to the 40 basis points suggested in the rules attached to the NOPR, the cap is reduced to 30 basis points. This revised cap level is reasonable in that it preserves the intended alignment between the utility's financial experience to the customer's experience in paying the GCA while not unduly affecting the utility's overall financial risk. The Hearing Commissioner further agrees that cap on the sharing amounts should be determined in consideration of only the equity share of the capital structure. Hence, the Hearing Commission adopts subparagraph 4607(c) (II) as follows:

> the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point pre-tax return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

j. Force Majeure Events

83. In its initial comments, Public Service argues that extreme changes in gas commodity costs present asymmetric risks and that the Commission should thus exclude "large price breakthrough events" outside of the utility's control.[47] Public Service argues that excluding costs associated with a "force majeure" event—defined as a period of time where prices rise greater than a certain multiple of average prices—would nonetheless align with the requirement in SB 23-291 for an incentive mechanism with symmetrical risk and reward. Alternately, Public Service states that the incentive mechanism cap could be set to $2.5 million annually, which

[47] Public Service Initial Comments, p. 31.

would exclude the financial impact of those price breakthrough events from providing an outsized impact to the incentive penalty amount.

84. Black Hills supports the recommendation that any GPIM must allow for force majeure exclusions for events outside of the utility's control.[48]

85. The Hearing Commission agrees that a force majeure provision should be included within the rules governing the implementation of a utility's GPIM. Paragraph 4607(d) is therefore introduced based on the rule language proposed by Public Service:

> The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception will allow the utility to exclude costs from the GPIM that are deemed to be associated with the force majeure event as defined by the utility's tariffs on file with the Commission.

k. Reconciliation of GPRM and GPIM Amortizations

86. In its initial comments, Black Hills explains that it is necessary for the Commission to reconcile the implementation of the GPRMP and the adopted GPIM, particularly in light of the maximum caps and minimum thresholds in the GPRMP.[49] Atmos similarly argues in its initial comments that the rules should allow flexibility to implement a GPRMP surcharge consistent with the utility's existing GPRMP.[50] Atmos further agrees with Black Hills and Public Service that the potential interaction of the GPIM with the GPRMP will need to be resolved.[51]

87. In its post-hearing comments, Public Service offers recommended additional provisions intended to harmonize the operation of the utility's GPRMP with the GPIM. Public Service states that it is reasonable from a customer bill mitigation perspective for the

[48] Black Hills Post-Hearing Comments, p. 13.
[49] Black Hills Initial Comments, p. 5.
[50] Atmos Initial Comments, p. 9.
[51] Atmos Response Comments, p. 5.

utilities to defer any positive GPIM sharing amounts accrued during periods when the GCA rises above the GPRMP upper bound.[52] In other words, when GCA rates are constrained by a maximum cap pursuant to the GPRMP, any positive GPIM sharing amounts would be deferred, while negative GPIM sharing amounts will be recognized and offset against any previously deferred positive GPIM sharing amounts, pending certain circumstances. Public Service explains that when the GCA calculation plus any GPIM sharing amount is above the GPRMP cap level, the GPIM sharing amount would not be accounted for in the deferred GCA account but would instead be recorded elsewhere, eligible to offset any negative GPIM sharing amounts accrued, for up to four GCA quarterly periods (initial GCA period + subsequent three GCA periods). If there is any remaining GPIM carryforward amounts after four GCA periods, those sharing amounts would expire and no longer be available to offset any future GPIM sharing amounts. Public Service argues that this approach balances customer bill impact sensitivity experienced during prolonged periods of high gas prices with the eligibility of incentives to the utility during such periods.[53]

88. Public Service goes on to explain that, in a scenario where the GCA less a negative GPIM sharing amount is below the GPRMP minimum level, the utility would still account for the sharing amount in the GCA deferred cost calculation until a subsequent GCA calculation results in a rate above the minimum limit level. Public Service explains that any deferred sharing amount would be made available for an indefinite period under this proposal.[54]

89. The Hearing Commission appreciates Public Service's proposed framework for addressing the interaction of the GPRMP and GPIM with respect to the GCA deferred cost calculation. The proposal fosters the necessary integration of the two mechanisms required by

[52] Public Service Post-Hearing Comments, p. 7.
[53] Public Service Post-Hearing Comments, p. 10.
[54] Public Service Post-Hearing Comments, pp. 11-12.

SB 23-291. Subparagraphs 4607(e)(I) and (II) are therefore introduced based on the rule language proposed by Public Service.

l. GPIM Test Period

90. In the conclusion of its initial comments, Public Service suggests that, regardless of the final structure of the GPIM adopted in this rulemaking, the Commission should make the first year of the mechanism a "test period and report year."[55] Public Service anticipates that the new elements to the GPIM will likely cause complications, such that the first year should be dedicated to implementation and adjustments to the GPIM as well as "proofing of the reporting process." Public Service further suggests that the Commission may wish to revise its plans after "real-life experience with the new mechanism."

91. The Hearing Commissioner declines to adopt Public Service's request for an initial year of testing the utility's GPIM before sharing amounts are implemented in the GCA deferred cost calculation. The proposed GPIM has been carefully vetted in this rulemaking and the precursor pre-rulemaking proceedings. Furthermore, each utility required to implement a GPIM must file an application to introduce GPIM provisions in its GCA tariff sheets. That additional review combined with the significant modifications to the GPIM made in accordance with this Decision sufficiently mitigates against the unexpected complications predicted by Public Service.

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

92. Rule 4608 in the GCA Rules generally sets forth the filing requirements and prudence review procedures for the Utility Gas Purchase and Deferred Balance Report (GPDBR).

[55] Public Service Initial Comments, p. 40.

The modifications to Rule 4608 presented in the NOPR remove provisions that relate to the Existing GPIM Rule.

93. The Hearing Commission adopts the revisions to Rule 4608 set forth in the NOPR, consistent with the modifications to the GPIM addressed above.

8. Rule 4609 – Contents of the GPDBR

a. Attachment 1 to the GPDBR

94. Proposed paragraph 4609(a) requires each gas utility to provide in Attachment 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.

95. In its initial comments, Black Hills suggests that the Commission correct a clerical error in the proposed rules by removing the repeated words "associated with" in subparagraph 4609(a)(III).

96. The error in rule 4609(a)(II) shall be corrected and the proposed rule revisions shall otherwise be adopted.

b. Attachment 6 to the GPDBR

97. The NOPR also included proposed revisions to paragraph 4609(f) addressing Attachment 6 to the GPDBR. The GPIM results 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).

98. The Hearing Commission largely adopts the modifications to paragraph 4609(f) consistent with the modifications to the GPIM addressed above.

IV. CONCLUSION

99. The statutory authority for the rules adopted by this Decision 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.

100. For the reasons discussed above, the Hearing Commissioner adopts modified GCA Rules as set forth in legislative format (Attachment A) and final format (Attachment B) attached to this Decision.

101. Being fully advised in this matter and consistent with the above discussion, in accordance with § 40-6-109, C.R.S., the Hearing Commissioner now transmits to the Commission the record in this proceeding along with this Recommended Decision and attachments.

V. ORDER

A. It Is Ordered That:

1. Consistent with the above discussion, the Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* 723-4, attached to this Recommended Decision as Attachments A and B are adopted.

2. The rules in redline (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

3. This Recommended Decision will be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

4. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision will be served upon the parties, who may file exceptions to it.

5. If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision will become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

6. If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the Hearing Commissioner and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

7. If exceptions to this Recommended Decision are filed, they may not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)

STATE OF COLORADO
THE PUBLIC UTILITIES COMMISSION
NIL SINE NUMINE

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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Hearing Commissioner

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

GAS COST ADJUSTMENT, PRUDENCE REVIEW, AND PERFORMANCE INCENTIVE

4600. Overview and Purpose.

Rules 4601 through 4610 are used by utilities to revise gas rates on an expedited basis, to reduce the volatility of gas costs for customers, and to improve their management of gas costs. These rules provide instructions for the filing of: gas cost adjustment filings; annual gas purchase plan submittals; annual gas purchase and deferred balance reports; gas price risk mitigation plans; and gas performance incentive mechanisms~~ applications~~. The purpose of the Gas Cost Adjustment is to enable utilities, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the utility's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase and Deferred Balance Report is to present the utility's actual purchases of gas commodity and upstream services during each month of the gas purchase year. The combined purpose of the Gas Price Risk Mitigation Plan and the Gas Performance Incentive Mechanism ~~application ~~is to address the volatility of gas commodity costs recovered from the utility's customers and to align the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs~~propose for review and approval a performance incentive mechanism that establishes a gas cost benchmark and applies a risk sharing mechanism~~.

4601. Definitions.

The following definitions apply to rules 4600 through ~~4609 ~~4610 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Account No. 191" means an account under the Federal Energy Regulatory Commission Uniform System of Accounts (USOA) used to account for the difference between purchased gas costs and revenues collected by a utility's gas cost adjustment.

(b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.

(c) "Base rates" means the utility's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

(d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.

(e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.

(f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.

(g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals, approved hedging program costs, and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.

(h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.

(i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.

(j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.

(k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.

(l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.

(m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.

(n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.

(o) "GCA filing" means an application or advice letter filing to adjust the GCA rate.

(p) "GCA rate area" means the geographic portion of the utility's service area in which a GCA rate is calculated and billed to customers. A utility may have a single GCA rate area that covers its entire service area or multiple GCA rate areas as established by the Commission.

(q) "Gas performance incentive mechanism" (GPIM) means an incentive mechanism implemented in conjunction with a GPRMP that aligns the utility's financial incentives with the financial interests of its customers regarding incurred ~~shares the risk of~~ gas commodity costs ~~between the utility and its customers~~.

~~(r) "GPIM application" means an application pursuant to rule 4607 establishing a GPIM.~~

~~(s) "GPIM benchmark" means a benchmark calculated based on verifiable, reported market indices, with a reasonable adjustment, for comparison with actual commodity costs incurred by the utility.~~

(r) "GPIM total gas costs" means the utility's incurred expenditures on gas commodity for applicable sales gas rate schedules in each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(s) "GPIM total gas quantity" means the quantity of gas commodity purchased (Mcf or Dth) for applicable sales gas rate schedules for each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(t) "Gas price risk management plan" (GPRMP) means a plan governing the calculation of the GCA subject to a maximum cap and a minimum threshold pursuant to paragraph 4603(g).

(~~t~~u) "Gas purchase and deferred balance report" (GPDBR) means a report pursuant to rule 4608 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

(~~u~~v) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.

(~~v~~w) "Gas purchase year" means a 12-month period from July 1 through June 30.

(~~w~~x) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.

(~~x~~y) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).

(~~y~~z) "Long-term contract" means a firm, fixed-price supply contract with an initial term of 12 months of more in duration.

(~~z~~aa) "Mil" means one-tenth of one cent ($0.001).

(~~aa~~bb) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.

(~~bb~~cc) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.

(~~cc~~dd) "Propane utility" means a public utility as defined in § 40-1-103, C.R.S., that operates for the purpose of supplying the public propane but does not supply natural gas or other fuels.

(~~dd~~ee) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.

(~~ee~~ff) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.

(~~ff~~gg) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.

(~~gg~~hh) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

4602. Schedule for Filings by Utilities.

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule.

(a) Utilities with more than 50,000 full service customers shall file with the Commission quarterly GCA filings. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(b) Utilities with fewer than 50,000 full service customers shall file with the Commission either quarterly GCA filings or two GCA filings per year with effective dates for GCA rates of November 1 and April 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(c) Propane utilities shall file an annual GCA filing with an effective date of November 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(d) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

(e) The GPDBR for the preceding gas purchase year in which a GPP was filed shall be filed annually by October 1.

(f) All utilities shall implement a GPRMP through their GCA filings. Modifications to a GPRMP shall be accomplished through an application filing separate from a GCA filing.

(~~f~~g) Utilities with fewer than 50,000 full service customers and propane utilities are not required to ~~file~~ include a GPIM ~~applications~~ in their GCA tariff sheets pursuant to rule 4607.

(~~g~~h) Utilities with more than ~~500,000~~50,000 full service customers shall file an ~~initial GPIM~~ application to include a GPIM within their GCA tariff sheets pursuant to rule 4607 within 60 days of the effective date of these rules ~~in advance of the 2023-2024 hearing season for a period extending through the gas purchase year ending in June 2025. GPIM applications for periods after June 2025 shall be filed pursuant to rule 4607 at least every three years~~. Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing.

~~(h) Utilities with more than 50,000 full service customers but fewer than 500,000 full service customers shall file an initial GPIM application pursuant to rule 4607 no later than September 1, 2023 for a period extending through the gas purchase year ending in June 2026. GPIM applications for periods after June 2026 shall be filed pursuant to rule 4607 at least every three years.~~

~~(i) After each heating season covered by a GPIM, the utility shall file a report on its performance no later than October 1. Commission staff shall review the report and confer with the utility regarding whether it is appropriate to continue the GPIM.~~

4603. Gas Cost Adjustments.

(a) Scheduled filings. A utility shall submit a GCA filing to adjust its GCA. The GCA filing shall be filed pursuant to the schedule provided in rule 4602. The GCA filing shall be submitted not less than two weeks in advance of the proposed effective date.

(b) Additional filings. If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may submit a GCA filing to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent ($0.01) per Mcf or Dth.

(c) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.

(d) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.

(e) ~~Price volatility risk management costs (~~Financial gas commodity hedging~~)~~. Costs related to gas price volatility risk management through financial hedging for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4608.

(f) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

GCA = (current gas cost + deferred gas cost) - (base gas cost).

(g) Gas price risk management plan. The calculation of the GCA shall be subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs in accordance with the utility's gas price risk management plan as approved by the Commission. Prudently incurred costs above the maximum cap shall be recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs, as determined by the Commission. Collections at the minimum threshold shall be recorded in a reserve fund, not to exceed an amount established by the Commission, and shall be used to offset any deferred balance of prudently incurred costs above the maximum cap.

4604. Contents of GCA Filings.

(a) A GCA filing shall meet the following requirements.

(I) Every GCA filing shall contain attachments 1 through 9. The attachments shall meet the requirements set out in this rule.

(II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.

(III) Attachments 2, 3, 5, and 6 shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(IV) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application. Work-papers shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(V) The filing shall cross-reference the proceeding numbers of the associated GPP submittals.

(VI) An explanation of all pro forma adjustments shall be provided, if applicable.

(b) GCA attachment No. 1 - GCA summary. This attachment shall clearly illustrate all of the following principles.

(I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis.

(II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis; and

(III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.

(c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity. The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP, as required pursuant to rule 4606.

(I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil ($0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

(II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.

(d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs, the calculation of deferred gas cost, the implementation of the utility's GPRMP, and the calculation of the GPIM symmetric sharing amounts, as approved by the Commission. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, GPIM ~~performance results~~sharing amounts, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity for the next 12-month period. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its GCA filings, the utility shall reflect actual deferred costs for the most recent period, or as otherwise approved by the Commission. ~~The results of the GPIM sharing shall be calculated on an annual basis and included in the deferred balance.~~

(e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently effective rates for sales gas service and, where applicable, gas transportation service.

(f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:

(I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and

(II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.

(g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:

(I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and

(II) derive the amount of the GCA applied to each specific sales gas customer class, subject to the utility's GPRMP and GPIM, and, where applicable, gas transportation customer rate classes.

(h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:

(I) current and proposed GCA rates and percentage change;

(II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;

(III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and

(IV) a statement that the utility made a separate gas purchase report filing in accordance with rule 4608 to begin the initial prudence review evaluation process for the prior gas purchase year.

(i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.

(j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.

(k) GCA attachment No. 10 – GPIM sharing amounts. As applicable, this attachment shall detail the calculation of GPIM sharing amounts per rule 4607 and any sharing amounts included in the deferred gas cost calculation presented in attachment No. 3. The calculation of the sharing amounts shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

4605. Gas Purchase Plans.

(a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

(b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:

(I) the information required by rule 4606;

(II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;

(III) the utility's forecasted pricing for each receipt point/area; and

(IV) the utility's portfolio management plan.

(c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.

(d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.

(e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.

(f) Modified GPP. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

4606. Contents of the GPP.

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

(b) GPP attachment No. 2 - gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.

(c) GPP attachment No. 3 - portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.

(d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:

(I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand.

(II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.

(III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.

(IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

4607. Gas Performance Incentive Mechanism ~~Applications~~.

In conjunction with its GPRMP, ~~A~~ the utility shall implement a GPIM in accordance with this rule and ~~application shall contain the following elements. The utility shall specifically reference and respond to~~ the ~~requirements~~ specific terms set forth in its GCA tariff sheets. ~~of paragraphs (a) through (d) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.~~ The utility shall implement a GPIM for each GCA rate area with more than 50,000 full service customers or each purchasing region as specified in the utility's GPP.

(a) GPIM benchmark gas rate. ~~Methodology to establish the GPIM benchmark for commodity gas purchases based on verifiable, reported market indices, with a reasonable adjustment, and for appropriate locations.~~The GPIM benchmark gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that same quarter in the previous year divided by the GPIM total gas quantity for the same quarter in the previous year.

(b) GPIM actual gas rate. The GPIM actual gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that quarter divided by the GPIM total gas quantity for that same quarter.

(c) GPIM sharing amount. The GPIM sharing amount will be calculated as four percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate, either positive or negative, multiplied by the GPIM total gas quantity for the completed calendar quarter preceding the GCA filing, subject to the following limitations:

(I) the GPIM sharing amount for a quarter shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth; and

(II) the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point pre-tax return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

(d) The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception will allow the utility to exclude costs from the GPIM that are deemed to be associated with the force majeure event as defined by the utility's tariffs on file with the Commission.

(e) Unless subject to the limitations in paragraph 4607(c), the GPIM sharing amount shall be accounted for in the utility's deferred gas cost calculation for the quarterly GCA filing.

(I) To the extent a GCA calculation is subject to a maximum cap specified in a utility's GPRMP, any new positive GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to the following provisions.

(A) Any positive GPIM sharing amount not accounted for in the initial GCA quarterly filing following calculation of the GPIM sharing amount will be subject to a carryforward of the following three subsequent GCA quarterly filings, or a total of four GCA quarterly filings.

(B) The carried forward GPIM amount shall be eligible to offset incurred negative GPIM sharing amounts up to three subsequent quarterly GCA filings. Any carried-forward GPIM amounts remaining at the time of the fourth subsequent quarterly GCA filing shall expire.

(II) To the extent a GCA calculation is subject to a minimum threshold specified in a utility's GPRMP, any new negative GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to the following provisions.

(A) Any negative GPIM sharing amount not accounted for in the first GCA quarterly filing following calculation of the GPIM sharing amount will be accounted for in the deferred gas cost calculation in a subsequent quarterly GCA filing in which the GCA calculation is above the minimum threshold.

~~(b) GPIM commodity gas volumes. Description and explanation of all gas volumes to be included in the GPIM.~~

~~(I) The volumes and costs associated with fixed-price, long-term supply contracts may be excluded from the GPIM and risk sharing calculation.~~

~~(II) The volumes and costs associated with storage injections and withdrawals, including both physical and contract storage, may be excluded from the GPIM and risk sharing calculation. Utilities shall provide a description of storage assets to be either included or excluded from the GPIM.~~

~~(III) The volumes and costs associated with associated with financial hedging shall be excluded from the GPIM and risk sharing calculation.~~

~~(IV) All other actual gas volumes and costs shall be subject to the GPIM with consideration of reasonable adjustments as determined by the Commission.~~

~~(c) Upstream supply costs. Description and explanation of upstream costs included in the GPIM risk sharing mechanism, including the methodology for developing an appropriate benchmark for such costs, if appropriate.~~

~~(d) Risk sharing amount. Methodology for calculating the risk sharing amount.~~

~~(I) A formula will calculate a percentage of the difference between the actual gas costs and the benchmark formula for applicable gas volumes, either positive or negative, borne or retained by the utility, subject to applicable limitations.~~

~~(II) The utility shall explain:~~

~~(A) any proposed deadband around the GPIM benchmark whereby price variation within the deadband is excluded from risk sharing formula;~~

~~(B) any proposed cap or floor on the results of the risk sharing; and~~

~~(C) any proposed methodology for applying force majeure or similar provisions to the risk sharing mechanism.~~

~~(III) Backcasting analysis, based on a minimum of the most recent three years of historical data, will demonstrate how the proposed GPIM benchmark would have been calculated and how the proposed risk sharing mechanism would have performed over the historical period. This analysis shall assume the utility made no changes to its actions in response to the mechanism and ignore any force majeure or similar events. The utility may, in its discretion, present additional analysis.~~

~~(e) Review for continuation of the GPIM. The utility may request that the Commission determine whether its GPIM should be discontinued based on prior performance. A comprehensive assessment of the GPIM shall be required no later than January 1, 2030.~~

4608. Gas Purchase and Deferred Balance Reports and Prudence Reviews.

(a) GPDBR filing requirements. The utility shall file a GPDBR in accordance with paragraph 4602(e) for the review and approval of the calculation of the deferred GCA balance ~~and~~ including the implementation of the utility's GPIM, as applicable, ~~performance and sharing amount~~ for the previous four quarters ending June 30. The GPDBR shall be filed under the previous year's GPP proceeding number (filed approximately 15 months previously). Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPDBR filing.

(b) Prudence review process. Based on the initial evaluation of the GPDBR, including the results of ~~any active~~the GPIM, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GDBPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

(c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action). The Commission may consider, as appropriate, whether the utility employed carefulness, precaution, attentiveness, and good judgment.

~~(d) GPIM shared savings. A utility may request approval of any shared savings amounts under its GPIM based upon a review of the drivers of the sharing amounts and the appropriateness of the sharing amounts.~~

(~~e~~d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

(~~f~~e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

4609. Contents of the GPDBR.

A GPDBR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA filing pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work-papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPDBR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year. Each gas utility shall provide a description and explanation of the following:

(I) the volumes and costs associated with fixed-price, long-term supply contracts;

(II) the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and

(III) the volumes and costs associated with financial hedging.

(b) GPDBR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.

(c) GPDBR attachment No. 3 - actual portfolio purchases. This attachment shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4608(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.

(d) GPDBR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

(I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;

(II) an itemized listing of the specific costs the utility incurred to purchase upstream services;

(III) actual peak day demand experienced by the utility during the gas purchase year; and

(IV) an itemized list of capacity release volumes and revenues.

(e) GPDBR attachment No. 5 - deferred balances. This attachment shall provide monthly deferred balances for the 12 months ending June 30.

(f) GPDBR attachment No. 6 - GPIM results. This attachment shall provide, for the 12 months ending June 30:

(I) the ~~monthly~~ quarterly GPIM benchmark ~~calculation~~ gas rates and GPIM actual gas rates~~including market indices used in the formulation~~; ~~and~~

(II) the quarterly and twelve-month cumulative GPIM ~~risk~~ sharing ~~calculation including application of any applicable deadband, cap or floor~~amounts~~.~~; and

(III) the calculation of the cap pursuant to subparagraph 4607(c)(II).

4610. Confidentiality.

(a) For each attachment filed by the utility as confidential under rules 4600 through 4610, the utility shall provide, at a minimum, a version of the attachment with publicly available information.

(b) The Office of the Utility Consumer Advocate (UCA) may provide each utility annually, on or before January 1 of each year, an executed generic nondisclosure agreement with the utility so that the utility shall provide such confidential information to the UCA when any utility filings are made pursuant to rules 4600 through 4609 for the subsequent year.

4611. – 4699. [Reserved].

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

GAS COST ADJUSTMENT, PRUDENCE REVIEW, AND PERFORMANCE INCENTIVE

4600. Overview and Purpose.

Rules 4601 through 4610 are used by utilities to revise gas rates on an expedited basis, to reduce the volatility of gas costs for customers, and to improve their management of gas costs. These rules provide instructions for the filing of: gas cost adjustment filings; annual gas purchase plan submittals; annual gas purchase and deferred balance reports; gas price risk mitigation plans; and gas performance incentive mechanisms. The purpose of the Gas Cost Adjustment is to enable utilities, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the utility's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase and Deferred Balance Report is to present the utility's actual purchases of gas commodity and upstream services during each month of the gas purchase year. The combined purpose of the Gas Price Risk Mitigation Plan and the Gas Performance Incentive Mechanism is to address the volatility of gas commodity costs recovered from the utility's customers and to align the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs.

4601. Definitions.

The following definitions apply to rules 4600 through 4610 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Account No. 191" means an account under the Federal Energy Regulatory Commission Uniform System of Accounts (USOA) used to account for the difference between purchased gas costs and revenues collected by a utility's gas cost adjustment.

(b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.

(c) "Base rates" means the utility's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

(d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.

(e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.

(f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.

(g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals, approved hedging program costs, and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.

(h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.

(i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.

(j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.

(k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.

(l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.

(m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.

(n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.

(o) "GCA filing" means an application or advice letter filing to adjust the GCA rate.

(p) "GCA rate area" means the geographic portion of the utility's service area in which a GCA rate is calculated and billed to customers. A utility may have a single GCA rate area that covers its entire service area or multiple GCA rate areas as established by the Commission.

(q) "Gas performance incentive mechanism" (GPIM) means an incentive mechanism implemented in conjunction with a GPRMP that aligns the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs.

(r) "GPIM total gas costs" means the utility's incurred expenditures on gas commodity for applicable sales gas rate schedules in each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(s) "GPIM total gas quantity" means the quantity of gas commodity purchased (Mcf or Dth) for applicable sales gas rate schedules for each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(t) "Gas price risk management plan" (GPRMP) means a plan governing the calculation of the GCA subject to a maximum cap and a minimum threshold pursuant to paragraph 4603(g).

(u) "Gas purchase and deferred balance report" (GPDBR) means a report pursuant to rule 4608 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

(v) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.

(w) "Gas purchase year" means a 12-month period from July 1 through June 30.

(x) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.

(y) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).

(z) "Long-term contract" means a firm, fixed-price supply contract with an initial term of 12 months of more in duration.

(aa) "Mil" means one-tenth of one cent ($0.001).

(bb) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.

(cc) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.

(dd) "Propane utility" means a public utility as defined in § 40-1-103, C.R.S., that operates for the purpose of supplying the public propane but does not supply natural gas or other fuels.

(ee) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.

(ff) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.

(gg) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.

(hh) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

4602. Schedule for Filings by Utilities.

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule.

(a) Utilities with more than 50,000 full service customers shall file with the Commission quarterly GCA filings. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(b) Utilities with fewer than 50,000 full service customers shall file with the Commission either quarterly GCA filings or two GCA filings per year with effective dates for GCA rates of November 1 and April 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(c) Propane utilities shall file an annual GCA filing with an effective date of November 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(d) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

(e) The GPDBR for the preceding gas purchase year in which a GPP was filed shall be filed annually by October 1.

(f) All utilities shall implement a GPRMP through their GCA filings. Modifications to a GPRMP shall be accomplished through an application filing separate from a GCA filing.

(g) Utilities with fewer than 50,000 full service customers and propane utilities are not required to include a GPIM in their GCA tariff sheets pursuant to rule 4607.

(h) Utilities with more than 50,000 full service customers shall file an application to include a GPIM within their GCA tariff sheets pursuant to rule 4607 within 60 days of the effective date of these rules. Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing.

4603. Gas Cost Adjustments.

(a) Scheduled filings. A utility shall submit a GCA filing to adjust its GCA. The GCA filing shall be filed pursuant to the schedule provided in rule 4602. The GCA filing shall be submitted not less than two weeks in advance of the proposed effective date.

(b) Additional filings. If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may submit a GCA filing to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent ($0.01) per Mcf or Dth.

(c) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.

(d) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.

(e) Financial gas commodity hedging. Costs related to gas price volatility risk management through financial hedging for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4608.

(f) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

GCA = (current gas cost + deferred gas cost) - (base gas cost).

(g) Gas price risk management plan. The calculation of the GCA shall be subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs in accordance with the utility's gas price risk management plan as approved by the Commission. Prudently incurred costs above the maximum cap shall be recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs, as determined by the Commission. Collections at the minimum threshold shall be recorded in a reserve fund, not to exceed an amount established by the Commission, and shall be used to offset any deferred balance of prudently incurred costs above the maximum cap.

4604. Contents of GCA Filings.

(a) A GCA filing shall meet the following requirements.

(I) Every GCA filing shall contain attachments 1 through 9. The attachments shall meet the requirements set out in this rule.

(II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.

(III) Attachments 2, 3, 5, and 6 shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(IV) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application. Work-papers shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(V) The filing shall cross-reference the proceeding numbers of the associated GPP submittals.

(VI) An explanation of all pro forma adjustments shall be provided, if applicable.

(b) GCA attachment No. 1 - GCA summary. This attachment shall clearly illustrate all of the following principles.

(I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis.

(II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis; and

(III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.

(c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity. The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP, as required pursuant to rule 4606.

(I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil ($0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

(II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.

(d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs, the calculation of deferred gas cost, the implementation of the utility's GPRMP, and the calculation of the GPIM symmetric sharing amounts, as approved by the Commission. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, GPIM sharing amounts, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity for the next 12-month period. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its GCA filings, the utility shall reflect actual deferred costs for the most recent period, or as otherwise approved by the Commission.

(e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently effective rates for sales gas service and, where applicable, gas transportation service.

(f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:

(I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and

(II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.

(g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:

(I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and

(II) derive the amount of the GCA applied to each specific sales gas customer class, subject to the utility's GPRMP and GPIM, and, where applicable, gas transportation customer rate classes.

(h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:

(I) current and proposed GCA rates and percentage change;

(II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;

(III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and

(IV) a statement that the utility made a separate gas purchase report filing in accordance with rule 4608 to begin the initial prudence review evaluation process for the prior gas purchase year.

(i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.

(j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.

(k) GCA attachment No. 10 – GPIM sharing amounts. As applicable, this attachment shall detail the calculation of GPIM sharing amounts per rule 4607 and any sharing amounts included in the deferred gas cost calculation presented in attachment No. 3. The calculation of the sharing amounts shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

4605. Gas Purchase Plans.

(a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

(b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:

(I) the information required by rule 4606;

(II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;

(III) the utility's forecasted pricing for each receipt point/area; and

(IV) the utility's portfolio management plan.

(c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.

(d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.

(e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.

(f) Modified GPP. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

4606. Contents of the GPP.

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

(b) GPP attachment No. 2 - gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.

(c) GPP attachment No. 3 - portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy

for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.

(d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:

(I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand.

(II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.

(III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.

(IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

4607. Gas Performance Incentive Mechanism.

In conjunction with its GPRMP, the utility shall implement a GPIM in accordance with this rule and the specific terms set forth in its GCA tariff sheets. The utility shall implement a GPIM for each GCA rate area with more than 50,000 full service customers or each purchasing region as specified in the utility's GPP.

(a) GPIM benchmark gas rate. The GPIM benchmark gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that same quarter in the previous year divided by the GPIM total gas quantity for the same quarter in the previous year.

(b) GPIM actual gas rate. The GPIM actual gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that quarter divided by the GPIM total gas quantity for that same quarter.

(c) GPIM sharing amount. The GPIM sharing amount will be calculated as four percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate, either positive or negative, multiplied by the GPIM total gas quantity for the completed calendar quarter preceding the GCA filing, subject to the following limitations:

(I) the GPIM sharing amount for a quarter shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth; and

(II) the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point pre-tax return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

(d) The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception will allow the utility to exclude costs from the GPIM that are deemed to be associated with the force majeure event as defined by the utility's tariffs on file with the Commission.

(e) Unless subject to the limitations in paragraph 4607(c), the GPIM sharing amount shall be accounted for in the utility's deferred gas cost calculation for the quarterly GCA filing.

(I) To the extent a GCA calculation is subject to a maximum cap specified in a utility's GPRMP, any new positive GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to the following provisions.

(A) Any positive GPIM sharing amount not accounted for in the initial GCA quarterly filing following calculation of the GPIM sharing amount will be subject to a carryforward of the following three subsequent GCA quarterly filings, or a total of four GCA quarterly filings.

(B) The carried forward GPIM amount shall be eligible to offset incurred negative GPIM sharing amounts up to three subsequent quarterly GCA filings. Any carried-forward GPIM amounts remaining at the time of the fourth subsequent quarterly GCA filing shall expire.

(II) To the extent a GCA calculation is subject to a minimum threshold specified in a utility's GPRMP, any new negative GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to the following provisions.

(A) Any negative GPIM sharing amount not accounted for in the first GCA quarterly filing following calculation of the GPIM sharing amount will be accounted for in the deferred gas cost calculation in a subsequent quarterly GCA filing in which the GCA calculation is above the minimum threshold.

4608. Gas Purchase and Deferred Balance Reports and Prudence Reviews.

(a) GPDBR filing requirements. The utility shall file a GPDBR in accordance with paragraph 4602(e) for the review and approval of the calculation of the deferred GCA balance including the implementation of the utility's GPIM, as applicable, for the previous four quarters ending June 30. The GPDBR shall be filed under the previous year's GPP proceeding number (filed approximately 15 months previously). Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPDBR filing.

(b) Prudence review process. Based on the initial evaluation of the GPDBR, including the results of the GPIM, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GDBPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

(c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action). The Commission may consider, as appropriate, whether the utility employed carefulness, precaution, attentiveness, and good judgment.

(d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

(e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

4609. Contents of the GPDBR.

A GPDBR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility’s GPP submittal as required pursuant to rule 4606 and GCA filing pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work-papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPDBR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year. Each gas utility shall provide a description and explanation of the following:

(I) the volumes and costs associated with fixed-price, long-term supply contracts;

(II) the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and

(III) the volumes and costs associated with financial hedging.

(b) GPDBR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.

(c) GPDBR attachment No. 3 - actual portfolio purchases. This attachment shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4608(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.

(d) GPDBR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

(I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;

(II) an itemized listing of the specific costs the utility incurred to purchase upstream services;

(III) actual peak day demand experienced by the utility during the gas purchase year; and

(IV) an itemized list of capacity release volumes and revenues.

(e) GPDBR attachment No. 5 - deferred balances. This attachment shall provide monthly deferred balances for the 12 months ending June 30.

(f) GPDBR attachment No. 6 - GPIM results. This attachment shall provide, for the 12 months ending June 30:

(I) the quarterly GPIM benchmark gas rates and GPIM actual gas rates;

(II) the quarterly and twelve-month cumulative GPIM sharing amounts; and

(III) the calculation of the cap pursuant to subparagraph 4607(c)(II).

4610. Confidentiality.

(a) For each attachment filed by the utility as confidential under rules 4600 through 4610, the utility shall provide, at a minimum, a version of the attachment with publicly available information.

(b) The Office of the Utility Consumer Advocate (UCA) may provide each utility annually, on or before January 1 of each year, an executed generic nondisclosure agreement with the utility so that the utility shall provide such confidential information to the UCA when any utility filings are made pursuant to rules 4600 through 4609 for the subsequent year.

4611. – 4699. [Reserved].

Decision No. C25-0005

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.

COMMISSION DECISION ADDRESSING EXCEPTIONS TO DECISION NO. R24-0682 AND ADOPTING RULES

Issued Date: January 6, 2025
Adopted Date: December 30, 2024

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I. <u>BY THE COMMISSION</u>

A. Statement

1. On April 30, 2024, the Colorado Public Utilities Commission issued a 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. Specifically, the proposed amendments to the Gas Rules attached to the NOPR would continue the utilities' implementation of gas risk management plans and would 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. The NOPR also designated Chairman Eric Blank as Hearing Commissioner, pursuant to § 40-6-101(2)(a), C.R.S., for this rulemaking proceeding.

2. By Decision No. R24-0682 ("Recommended Decision"), issued on September 23, 2024, Hearing Commission Blank adopted amendments and additions to the Gas Rules governing the Gas Cost Adjustment ("GCA" or "GCA Rules"), set forth in the Gas Rules at 4 CCR 723-4-4600 through 4610.

3. By this Decision, the Commission addresses the exceptions to the Recommended Decision and adopts, with modifications, the rules established by the Recommended Decision. The adopted 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.

B. Background

4. The Recommended Decision provides a detailed description of the relevant provisions in SB 23-291 that required this rulemaking and its procedural history.

5. As relevant to our consideration of the exceptions to the Recommended Decision, Section 4 of SB 23-291 required each investor-owned gas utility to file with the Commission, on or before November 1, 2023, a Gas Price Risk Management Plan ("GPRMP") to address the volatility of fuel costs recovered from the utility's customers pursuant to the utility's GCA filings. A GPRMP was established for each of Colorado's four investor-owned gas utilities through utility application proceedings that concluded in November 2023. Section 4 also required the Commission to establish, in addition to the GPRMPs, "mechanisms that align an investor-owned utility's financial incentives with the financial interests of its customers regarding incurred fuel costs."

6. The Recommended Decision explains that the adoption of rules that integrate the GPRMPs into the Commission's GCA framework satisfies much of the requirement in SB 23-291 that the Commission protect Colorado gas utility customers while also improving the gas utilities' management of fuel cost. The GPRMPs, in combination with other actions taken by the utilities in accordance with their Gas Purchase Plans ("GPPs") pursuant to Rules 4605 and 4606 and with their financial hedging strategies addressed separately by application, will serve to reduce the volatility of fuel costs passed on to customers. The Recommended Decision further adopts a

modified GPIM, to further align the investor-owned utility's financial incentives with the financial interests of its customers regarding incurred fuel costs beyond what is achieved through the existing GCA framework and the recently established GPRMPs for each utility. The Recommended Decision concludes that the modified GPIM, as developed in Rule 4607, is the approach that is most suited to align the Commission's goals with the requirements of SB 23-291.

7. Consistent with the NOPR, the Recommended Decision explains that adopted revisions to the GCA Rules comprise two primary elements: paragraph 4603(g) incorporates the utilities GPRMPs as a permanent feature of gas cost recovery through the GCA, while proposed Rule 4607 establishes a new mechanism that shares as a financial incentive a portion of decreases and increases in gas commodity prices reflected in the utilities' GCAs.

8. Paragraph 4603(g) adopted by the Recommended Decision is based on the language in § 40-3-120(1), C.R.S., such that the calculation of the GCA is subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs. Costs above the maximum cap are recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs. Collections at the minimum threshold are recorded in a reserve fund to offset any deferred balance of prudently incurred costs above the maximum cap. The rule essentially defines the essence of a utility's GRPMP, and the rule is implemented through utility specific provisions in their GCA tariff sheets.

9. Rule 4607 defines the new financial incentive mechanism—a modified GPIM—to align the utility's financial incentives with the financial interests of customers as also required by SB 23-291. In essence, the proposed mechanism calculates the difference in gas costs between a recently concluded quarter and the same three months in the prior year, splitting a portion of the

difference, subject to a deadband, either as a cost born by the utility's shareholders when there is an increase in gas costs or as a share of the savings in the form of earnings for the utility's shareholders. The proposed rule outlines a general structure for the modified GPIM. Certain other proposed rules, such as new definitions in Rule 4601, support the provisions set forth in proposed Rule 4607.

10. Exceptions to the Recommended Decision were timely filed on October 14, 2024, by Public Service Company of Colorado ("Public Service"), Atmos Energy Corporation ("Atmos"), and Black Hills Colorado Gas, Inc. ("Black Hills"). The Colorado Office of the Utility Consumer Advocate ("UCA") filed a response to those exceptions on October 28, 2024.

11. In brief, the three utilities filing exceptions object to the historic baseline proposed to be used for the GPIM. They further seek clarification on the GPIM's deadband, on the cap on GPIM incentives and penalties, and on the carryforward provisions of penalties and incentives when the utility's GPRMP is in operation. In addition, Atmos seeks additional rule language regarding force majeure, and Public Service seeks a one-year trial period for the GPIM before incentives or penalties are applied.

12. UCA responds to the utilities' exceptions by stating that it supports the Recommended Decision without modification because it embraces the intent of SB 23-291 and § 40-3-120, C.R.S.

13. On October 29, 2024, Durango Mountain Utilities, LLC ("DMU") filed a motion for leave to file out-of-time exceptions to the Recommended Decision. DMU explains that it is a propane utility that does not supply natural gas or other fuels to its customers and accordingly, it did not actively engage in this rulemaking proceeding. However, after realizing the implications of the proposed rules to be adopted by the Recommended Decision, DMU worked diligently to

prepare and file its own exceptions. DMU argues that good cause exists in this instance for the Commission to grant leave to file exceptions to the Recommended Decision out-of-time because no other similarly situated small propane utility has filed comments into this Proceeding or otherwise participated in this rulemaking thus far. DMU also notes that none of the other utilities or entities that have participated in the rulemaking will be impacted or prejudiced by DMU's proposed exceptions to the Recommended Decision.

14. For the reasons stated therein we find good cause to grant DMU's motion and to consider its exceptions to the Recommended Decision.

C. Discussion, Findings, and Conclusions

15. 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.

16. Consistent with the discussion below, we adopt the Recommended Decision with revisions based on our findings and analysis of the issues raised in the exceptions.

1. Rule 4602 – Schedule for Filings by Utilities

a. Propane Utility Exemption from GPRMP Requirements

17. Paragraph 4602(f) requires the utility's GCA to include a GPRMP 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 GPRMP must be accomplished through an application proceeding separate from a GCA filing.

18. In its exceptions to the Recommended Decision, DMU asks the Commission to exempt it from the requirement to file a GPRMP.

19. We agree with DMU that a GPRMP should not apply to a propane utility and therefore modify paragraph 4602(f) to exempt propane utilities from the GPRMP requirements.

b. Utility-Specific GPIM Applications

20. In response to the gas utilities' requests in written comments and at the rulemaking hearing on July 11, 2024, the Recommended Decision adopts provisions where each gas utility files an application to modify its GCA tariff sheets to implement a GPIM that is suited to the specific characteristics of that utility. However, each utility must adhere to basic framework for a GPIM as a rule-based framework as contemplated in Section 4 of SB 23-291.

21. Paragraph 4602(h) adopted by the Recommended Decision requires the utilities to file an application to include a GPIM within their GCA tariff sheets within 60 days of the effective date of these modified GCA Rules. Once established, the GPIM shall be implemented through the utility's GCA in accordance with the utility's GCA tariff sheets in effect. Modifications to a GPIM, once initially established, will also be accomplished by an application filing separate from the normal implementation of the GCA.

22. Based upon our review of the utilities' exceptions, and in accordance with the discussion below regarding Rule 4607, we adopt the GPIM application process in paragraph 4602(h) with certain modifications. Each utility with more than 50,000 customers providing natural gas commodity shall file an application to modify its GCA tariff sheets to include a GPIM. However, consistent with the discussion below, for utilities with more than 50,000 but

less than 500,000 full service customers (such as Atmos and Black Hills), the GPIM application will rely on the GPIM framework currently in the GCA Rules. In contrast, the GPIM application from a utility with more than 500,000 full service customers (such as Public Service) will rely on a modified GPIM framework in accordance with the GPIM developed in the NOPR, adopted by the Recommended Decision, and further modified by this Decision.

c. Review of GPIM

23. Public Service requests in its exceptions that the Commission adopt a trial period for the implementation of the modified GPIM framework, where the first twelve months after Commission approval of a utility's GPIM serves only as a reporting year to ensure the mechanism works as intended. Public Service suggests that if the first year were to be a test period, a utility could transact financial hedges and fixed-price contracts as appropriate without reservation as to the unknown (and untested) efficacy of such tools within the GPIM. Public Service also notes that the natural gas commodity market has experienced an atypical year in 2024 where prices have been very low. Public Service flatly states that a test year would have the "benefit" of removing this extremely low-priced period from the baseline for comparison in any GPIM.

24. In lieu of a trial period as suggested by Public Service, we will instead reestablish a comprehensive review process for the GPIM similar in form to the process contemplated in paragraph 4602(i) in the existing GCA Rules. Paragraph 4602(i) will require each utility to file an application for a renewal of its GPIM no later than 90 days after the conclusion of the first full heating season covered by the utility's GPIM. The rule specifies that the implementation of any already-established GPIM shall continue until the renewed GPIM goes into effect. The rule further requires the renewal application for the utilities with an initial GPIM based on the framework set forth in paragraph 4607(a) to present an analysis of the implementation of the utility's initial GPIM

as approved by the Commission and an analysis of GPIM benchmark gas rate and GPIM sharing amount in paragraph 4607(b) as if they had instead been implemented over the same period as the initial GPIM. Finally, we affirm that the utility may also propose in its renewal application to implement a modified GPIM provided that the Commission determines the modified GPIM comports with the requirements of SB 23-291 and specifically § 40-3-120, C.R.S.

2. Rule 4607 – Gas Performance Incentive Mechanism

25. Paragraph 4607(a) in the Recommended Decision ("GPIM Rule") sets forth the new symmetric sharing mechanism contemplated in § 40-3-120(2), C.R.S. As explained in the Recommended Decision, paragraph 4607(a) was intended to replace most of rule 4607 adopted in Proceeding No. 21R-0314G.

26. The GPIM benchmark gas rate defined in 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 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. 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.*, four 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.

a. Atmos' Exceptions

27. Atmos argues that the GPIM Rule fails to meet the criteria in SB 23-291 that modified Commission rules must align the financial incentives of the utility with the interests of

its customers regarding incurred fuel costs. Atmos contends that by comparing current gas costs against a historical benchmark, the GPIM Rule creates "a penalty and reward system" that will require utility customers to pay incentives based on market price changes having nothing to do with utility management and will fail to improve a utility's management of fuel costs. Atmos argues that the proposed rule arbitrarily adds risk for both the utility and its customers. Atmos alleges that "the goal of the Recommended Decision is for the gas utilities to suffer financial harm if gas prices rise" and thus provides perverse incentives—rather than trying to minimize gas prices, the utility will instead work to lock in fixed prices to the extent possible to avoid incurring financial harm. Atmos goes on to state that the GPIM Rule would deprive a utility of a reasonable opportunity to recover its prudently incurred costs based solely on a comparison to historical gas costs, rather than the actual gas procurement decisions made by the utility considering current market conditions.

28. Atmos further argues that the Recommended Decision lacks analysis regarding how a utility's current financial incentives conflict with the interests of its customers regarding incurred fuel costs, or how the historical benchmark adopted in the Recommended Decision will align the utility's incentives with the interests of its customers as required by § 40-3-120(2), C.R.S. Atmos states that the record in this rulemaking shows that utilities have faced political and financial consequences for high gas costs that are outside of their control and that there are other customer interests regarding fuel costs and utility rates that go beyond trying to keep gas costs constant year over year. For instance, Atmos contends that the Recommended Decision ignores customer interest in receiving accurate price signals based on competitive markets. Instead, Atmos suggests customers could end up making decisions contrary to their long-term interests because they are not seeing the price impacts of market changes in the cost of gas. Atmos likewise contends

that the GPIM Rule ignores customer interest in reasonable base rate stability, because the automatic reductions to a utility's earned rate of return due to market increases in gas commodity costs will cause the utilities to file more frequent rate cases and higher capital costs.

29. More generally, Atmos critiques the GPIM Rule by arguing that an incentive can only work if "the thing being measured is something within a person's control," yet nothing in the Recommended Decision explains or analyzes how natural gas utilities in Colorado can control the market price of natural gas. In theory, however, what the utilities can do to mitigate their risk from the GPIM Rule is to change their gas procurement strategies to ensure a greater share of gas transportation and commodity prices are locked in at levels comparable to the levels from the year before. According to Atmos, that approach is contrary to optimizing prices based on current market conditions.

30. Atmos thus asks the Commission to modify the GPIM in in the final GCA Rules to use a relevant and contemporaneous market index prices as the benchmark rather than a benchmark based on the prior year's gas costs. According to Atmos, this modification will achieve the statutory goals of aligning customer interests and utility incentives regarding fuel costs. Atmos adds that this different approach will also allow the GPIM to be compatible with the utilities' actual gas procurement activities in competitive markets and suggests that if the GPIM benchmark is based on an index reflecting contemporaneous market prices, utilities will be motivated to manage gas costs, to the extent they can, to moderate but not eliminate market price changes.

b. Black Hills' Exceptions

31. Black Hills echoes Atmos' concerns that the proposed GPIM Rule fails to meet the intent SB 23-291. Black Hills adds because the GPIM Rule provides no financial incentive for

utilities with respect to gas purchases, it fails "to further align the investor-owned utility's financial incentives with the financial interests of its customers regarding incurred fuel costs beyond what is achieved through the existing GCA framework" (citing the Recommended Decision) and is not based on the reality of those gas purchases. And like Atmos, Black Hills concludes that the GPIM Rule "is nothing more than a mechanism to punish gas utilities," because it would 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.

32. Black Hills also argues that the Recommended Decision conflates the GPRMPs with GPIMs whereas SB 23-291 sets out different requirements for the two mechanisms. According to Black Hills, the GPRMPs are intended to level or reduce the volatility of fuel costs, while GPIMs are intended to protect customers and improve the utility's management of fuel costs. Black Hills notes that the Recommended Decision specifically admits that the "adoption of rules that integrate the GPRMPs into the Commission's GCA framework satisfies much of the requirement in SB 23-291 that the Commission protect Colorado gas utility customers while also improving the gas utilities' management of fuel cost." Black Hills concludes that if the GPRMP and GCA framework already protects customers and improves the utility's management of fuel costs, there is no basis to implement the GPIM.

33. Black Hills states that it favors a forward-looking benchmark that allows for flexibility to adapt to factors that influence usage and price levels (which are out of a utility's control) to better align with a utility's purchase activity. Black Hills further clarifies that it objects to a benchmark based on a published monthly index as proposed by Public Service. Black Hills argues that a published index price does not accurately reflect the market value of the utility gas commodity supply, which could be represented as an index price plus a premium or minus a

discount, depending on location liquidity, purchasing power, supply and demand among other factors. Black Hills further argues that solely using a published monthly index rate would fail to account for intra-month purchase requirements, price movement, or the fact that intra-month purchases may not correlate with an established monthly index price. Rather than a published market index baseline, Black Hills suggests implementing a forward-looking approach that offers each utility the flexibility to tailor its GPIM structure, including the benchmark gas rate, to account for its portfolio design and purchasing requirements across various gas purchase locations.

c. Public Service's Exceptions

34. Public Service also objects to the use of a historical baseline in the GPIM Rule. Public Service instead recommends the use of published monthly prices reported in industry trade publications, which it says are indicative of current market prices.

35. Public Service argues that an historical baseline does not adequately reflect current market conditions. It further argues that an historical baseline creates an arbitrary outcome for both the Company and its customers—"one that is up to chance whether the Company or customers will receive a penalty or an incentive." Public Service states that an historical baseline that uses year-old price data prevents the utility from respond to price signals in any meaningful way. Public Service also notes that while the Commission has made a point to limit volatility experienced by customers, pegging any penalty or incentive to a single-period historical baseline would exacerbate volatility associated with gas commodity markets.

36. Public Service therefore asks the Commission to modify the GPIM in the final GCA Rules to use a current gas price index for the GPIM baseline. Public Service argues that if the baseline used current market prices, it is more likely the utility could successfully purchase gas at a favorable cost using purchasing and hedging strategies. Public Service also states that a current

index baseline would also better align the utility's financial incentives with the financial interest of its customers and would better incentivize the utility to "beat the market," because under that construct there would be a realistic opportunity to do so.

37. In the alternative, Public Service suggests that a multi-year historical period be used for the benchmark in the GPIM Rule. Specifically, the Company suggests that average prices over the previous four years be used as a historical baseline instead of only the previous year's historical prices. Public Service argues that a multi-year period of historical prices would provide a more stable and accurate benchmark, reducing the risk of significant penalties or incentives due to market fluctuations.

d. GPIM Benchmark Gas Rate

38. As stated above, the Recommended Decision establishes the GPIM benchmark gas rate as the actual total gas cost divided by the actual total gas quantity for the most recently concluded quarterly period in the previous calendar year.

39. Upon consideration of the utilities' exceptions to the Recommended Decision, we are sympathetic to their concerns about unintended consequences. We further see merit in adopting the modified GPIM proposed in the NOPR on a slower, more deliberate schedule by modifying the modified GPIM in certain specific ways as suggested in the exceptions and by limiting the initial applicability of the historic benchmark to utilities with more than 500,000 full service customers. This revised approach to introducing the modified GPIM 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.

40. Accordingly, we further modify Rule 4607. First, for the utilities with more than 50,000 but less than 500,000 full service customers, the applications to modify the utility's GCA tariff sheets will introduce a GPIM in accordance with the GPIM provisions currently within the GCA Rules. This framework for the GPIM is organized within paragraph 4607(a). Second, the modified GPIM proposed in the NOPR and modified by the Recommended Decision is housed within paragraph 4607(b) that will initially apply only to utilities with more 500,000 full service customers. By launching the introduction of the GPIM as soon as practicable for the utilities in this matter, we fulfill the intent of SB 23-291 to put in place the new financial alignment mechanism without the delay that would otherwise be caused by a trial period as suggested by Public Service in its exceptions. We further establish procedural means to address the concerns of the utilities regarding the immediate implementation of a GPIM using an historic benchmark.

41. In addition, we revise the historic GPIM benchmark gas rate in subparagraph 4607(b)(I) to be calculated as an average of the historic rates for same quarter in the prior three years as suggested as an alternative by Public Service in its exceptions. We expect that this approach will provide greater stability for the utilities and their customers.

e. GPIM Sharing Amount

42. The Recommended Decision 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.*, four percent as shown in the rules attached to this Decision) multiplied by the actual total gas quantity purchased. The rule includes a deadband provision, where the GPIM sharing amount shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth.

43. Public Service seeks clarity with respect to the deadband, asking the Commission to state whether the rule applies “marginally” or “fully.” Through a marginal application, the difference between a calculated GPIM Actual Gas Rate less the GPIM Benchmark Gas Rate is reduced by the $0.50/Dth deadband prior to being eligible for sharing. In contrast, the full application would subject the full $0.50/Dth to sharing without being netted against the deadband amount. Public Service states that the marginal method would provide gradualism, such that sharing amounts would be begin at $0.01/Dth multiplied by the other sharing parameters, after netting out the deadband amount. A full method would “eliminate gradualism” as sharing amounts would begin at $0.51/Dth multiplied by other factors in the equation set forth in the rule. Public Service presents an analysis of the two approaches and concludes that from 2016 through the first quarter of 2024, a “full” deadband would result in awarded cumulative incentives of approximately $5.7 million, while a “marginal” deadband would result in awarded incentives of approximately $5.5 million. While the analysis is indeed “interesting” in terms of cumulative effects, Public Service portrays the full method as a “cliff, potentially leading to inequitable incentives of penalties, especially for amounts only slightly outside the deadband.”

44. Atmos and Black Hills also ask the Commission to clarify the implementation of the deadband for sharing amounts in their exceptions.

45. Public Service also requests the Commission confirm that the calculation of the sharing amount based on the equity portion of the utility’s rate base in Rule 4607(c) should not be “grossed-up” for income tax expense.

46. We agree with the utilities that it is necessary to clarify that the deadband shall be implemented such that the GPIM sharing amounts apply to the amounts of the differences between the applicable benchmark and the GPIM actual gas rate excluding the amount of the deadband (or,

in the words of Public Service, the sharing amount is calculated "marginally" instead of "fully"). We likewise introduce a provision under subparagraph 4607(b)(III) to accomplish this clarification.

47. We also agree with Public Service that the calculation of the sharing amount should not be "grossed-up" for income tax expenses.

f. Maximum Sharing Amount

48. The Recommended Decision sets a cap on aggregate GPIM sharing amounts at an amount equal to a 30 basis point pre-tax return on the equity share of the utility's rate base determined on a twelve-month rolling basis.

49. In its exceptions, Public Service asks that the cap instead be implemented on a quarterly basis, set at 7.5 basis points per quarter or the 30 basis points divided by four quarters. According to Public Service, this modified cap would reduce risk exposure and provide greater operational flexibility to the utility. Public Service states that an annual maximum cap on penalties and incentives can swing by up to 60 basis points between quarters (even if restricted to 30 basis points over a rolling 12-month period), potentially creating significant earnings volatility. Public Service also asks that the Commission strike "pre-tax" from the provisions establishing the cap, in accordance with its other recommendation that the Commission clarify that sharing amounts would not be grossed up for income taxes.

50. Black Hills and Atmos ask the Commission to clarify that the GPIM cap should be allocated to the utility's different GCA areas (or purchasing regions) so that the cap for each area is not equal to the 30-basis point return on total rate base.

51. We deny Public Service's request to modify the twelve-month rolling cap into a quarterly measure. We are specifically concerned that a cap set at a 7.5 basis point return will

substantively diminish the intended alignment of the GPIM vis-à-vis the utilities given the volatile nature of the gas commodity market during heating seasons.

52. However, we find good cause to remove the "pre-tax" qualifier from the cap as suggested by Public Service consistent with our earlier clarification that GPIM sharing amounts will not be "gross-up" for income tax purposes. We also clarify, as requested by Black Hills and Atmos in their exceptions, that the overall cap is not intended to apply to each GCA rate area of each purchasing region. If necessary, the allocation of the overall cap can be addressed in the application proceedings contemplated in paragraphs 4602(h) and 4602(i).

g. Carry Forward Provisions

53. As explained in the Recommended Decision, the utilities asked the Hearing Commissioner to reconcile the implementation of the GPRMP and the GPIM, particularly considering the maximum caps and minimum thresholds in the GPRMP. The Recommended Decision largely adopts the proposal put forward by Public Service for addressing the interaction of the GPRMP and GPIM with respect to the GCA deferred cost calculation.

54. In their exceptions, Atmos and Black Hills ask that the Commission modify the provisions for carrying forward GPIM Rule incentives or penalties so that they are symmetrical, or, in other words, either by removing the expiration of carried forward incentives or by causing carried forward penalties to expire after a set amount of GCA quarterly filings.

55. We find good cause to modify the carry forward provisions by eliminating the expiration of the carried forward amounts. Carried forward amounts shall not expire after four GCA quarterly filings but shall carry forward indefinitely. This feature of the GPIM may be addressed in the GPIM renewal application proceedings contemplated in paragraph 4602(i).

h. Force Majeure Events

56. The Recommended Decision introduces a force majeure provision within the rules governing the implementation of a utility's GPIM using rule language proposed by Public Service.

57. In its exceptions, Atmos asks the Commission to expand the definition of force majeure in Rule 4607(d) to include force majeure events as defined in the utility's upstream gas supply, storage, and transportation agreements and tariffs.

58. We grant Atmos' request and modify the force majeure provisions in subparagraph 4607(b)(IV). However, because the intent of SB 23-291 is to preserve an alignment of incentives when gas commodity fuel costs rise and fall, we also replace "shall" with "may" in the second sentence of the rule to read: "The force majeure exception may allow the utility to exclude costs from the GPIM…"

II. <u>ORDER</u>

A. The Commission Orders That:

1. The exceptions to Decision No. R24-0682, filed by Public Service Company of Colorado on October 14, 2024, are granted, in part, and denied, in part, consistent with the discussion above.

2. The exceptions to Decision No. R24-0682, filed by Atmos Energy Corporation on October 14, 2024, are granted, in part, and denied, in part, consistent with the discussion above.

3. The exceptions to Decision No. R24-0682, filed by Black Hills Colorado Gas, Inc. on October 14, 2024, are granted, in part, and denied, in part, consistent with the discussion above.

4. The motion for leave to file out-of-time exceptions to Decision No. R24-0682, filed by Durango Mountain Utilities, LLC ("DMU") on October 29, 2024, is granted.

5. The exceptions to Decision No. R24-0682, filed by DMU on October 29, 2024, are granted, consistent with the discussion above.

6. The Commission adopts the rules recommended in Decision No. R24-0682, in their entirety, except for the modifications identified in this Decision.

7. The Rules Regulating Gas Utilities in 4 *Code of Colorado Regulations* 723-4, 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-0192G

8. 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.

9. 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

10. 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.

11. 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

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

GAS COST ADJUSTMENT, PRUDENCE REVIEW, AND PERFORMANCE INCENTIVE

4600. Overview and Purpose.

Rules 4601 through 4610 are used by utilities to revise gas rates on an expedited basis, to reduce the volatility of gas costs for customers, and to improve their management of gas costs. These rules provide instructions for the filing of: gas cost adjustment filings; annual gas purchase plan submittals; annual gas purchase and deferred balance reports; gas price risk mitigation plans; and gas performance incentive mechanisms~~ applications~~. The purpose of the Gas Cost Adjustment is to enable utilities, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the utility's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase and Deferred Balance Report is to present the utility's actual purchases of gas commodity and upstream services during each month of the gas purchase year. The combined purpose of the Gas Price Risk Management Plan and the Gas Performance Incentive Mechanism ~~application~~ is to address the volatility of gas commodity costs recovered from the utility's customers and to align the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs~~propose for review and approval a performance incentive mechanism that establishes a gas cost benchmark and applies a risk sharing mechanism~~.

4601. Definitions.

The following definitions apply to rules 4600 through ~~4609~~ 4610 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Account No. 191" means an account under the Federal Energy Regulatory Commission Uniform System of Accounts (USOA) used to account for the difference between purchased gas costs and revenues collected by a utility's gas cost adjustment.

(b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.

(c) "Base rates" means the utility's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

(d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.

(e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.

(f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.

(g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals, approved hedging program costs, and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.

(h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.

(i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.

(j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.

(k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.

(l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.

(m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.

(n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.

(o) "GCA filing" means an application or advice letter filing to adjust the GCA rate.

(p) "GCA rate area" means the geographic portion of the utility's service area in which a GCA rate is calculated and billed to customers. A utility may have a single GCA rate area that covers its entire service area or multiple GCA rate areas as established by the Commission.

(q) "Gas performance incentive mechanism" (GPIM) means an incentive mechanism implemented in conjunction with a GPRMP that aligns the utility's financial incentives with the financial interests of its customers regarding incurred ~~shares the risk of~~ gas commodity costs ~~between the utility and its customers~~.

~~(r) "GPIM application" means an application pursuant to rule 4607 establishing a GPIM.~~

~~(s) "GPIM benchmark" means a benchmark calculated based on verifiable, reported market indices, with a reasonable adjustment, for comparison with actual commodity costs incurred by the utility.~~

(r) "GPIM total gas costs" means the utility's incurred expenditures on gas commodity for applicable sales gas rate schedules in each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(s) "GPIM total gas quantity" means the quantity of gas commodity purchased (Mcf or Dth) for applicable sales gas rate schedules for each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(t) "Gas price risk management plan" (GPRMP) means a plan governing the calculation of the GCA subject to a maximum cap and a minimum threshold pursuant to paragraph 4603(g).

(~~t~~u) "Gas purchase and deferred balance report" (GPDBR) means a report pursuant to rule 4608 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

(~~u~~v) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.

(~~v~~w) "Gas purchase year" means a 12-month period from July 1 through June 30.

(~~w~~x) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.

(~~x~~y) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).

(~~y~~z) "Long-term contract" means a firm, fixed-price supply contract with an initial term of 12 months of more in duration.

(~~z~~aa) "Mil" means one-tenth of one cent ($0.001).

(~~aa~~bb) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.

(~~bb~~cc) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.

(~~cc~~dd) "Propane utility" means a public utility as defined in § 40-1-103, C.R.S., that operates for the purpose of supplying the public propane but does not supply natural gas or other fuels.

(~~dd~~ee) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.

(~~ee~~ff) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.

(~~ff~~gg) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.

(~~gg~~hh) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

4602. Schedule for Filings by Utilities.

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule.

(a) Utilities with more than 50,000 full service customers shall file with the Commission quarterly GCA filings. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(b) Utilities with fewer than 50,000 full service customers shall file with the Commission either quarterly GCA filings or two GCA filings per year with effective dates for GCA rates of November 1 and April 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(c) Propane utilities shall file an annual GCA filing with an effective date of November 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(d) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

(e) The GPDBR for the preceding gas purchase year in which a GPP was filed shall be filed annually by October 1.

(f) All utilities, except for propane utilities, shall implement a GPRMP through their GCA filings. Modifications to a GPRMP shall be accomplished through an application filing separate from a GCA filing.

(~~f~~g) Utilities with fewer than 50,000 full service customers and propane utilities are not required to ~~file~~ include a GPIM ~~applications~~ in their GCA tariff sheets pursuant to rule 4607.

(~~g~~h) Utilities with more than ~~500,000~~50,000 full service customers shall file an ~~initial GPIM~~ application to include a GPIM within their GCA tariff sheets pursuant to rule 4607 within 60 days of the effective date of these rules ~~in advance of the 2023-2024 hearing season for a period extending through the gas purchase year ending in June 2025. GPIM applications for periods after June 2025 shall be filed pursuant to rule 4607 at least every three years~~. The initial GPIM for utilities with more than 50,000 but less than 500,000 full service customers shall be established in accordance with paragraph 4607(a). The initial GPIM for utilities with more than 500,000 full service customers shall be established in accordance with paragraph 4607(b). Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing.

~~(h) Utilities with more than 50,000 full service customers but fewer than 500,000 full service customers shall file an initial GPIM application pursuant to rule 4607 no later than September 1, 2023 for a period extending through the gas purchase year ending in June 2026. GPIM applications for periods after June 2026 shall be filed pursuant to rule 4607 at least every three years.~~

(i) No later than 90 days after the conclusion of ~~After each~~ a full heating season covered by ~~a~~ the utility's initial GPIM, the utility shall file an ~~report on its performance no later than October 1~~application for the renewal of ~~. Commission staff shall review the report and confer with the utility regarding whether it is appropriate to continue~~ the GPIM. Implementation of the initial GPIM shall continue until the renewed GPIM goes into effect. For the utilities with an initial GPIM based on the framework set forth in paragraph 4607(a), the renewal application shall present an analysis of the implementation of the utility's initial GPIM as approved by the Commission and an analysis of GPIM benchmark gas rate and GPIM sharing amount in paragraph 4607(b) as if they had instead been implemented over the same period as the initial GPIM. The utility may propose to implement a modified GPIM provided that the Commission determines the modified GPIM comports with the requirements of § 40-3-120, C.R.S.

4603. Gas Cost Adjustments.

(a) Scheduled filings. A utility shall submit a GCA filing to adjust its GCA. The GCA filing shall be filed pursuant to the schedule provided in rule 4602. The GCA filing shall be submitted not less than two weeks in advance of the proposed effective date.

(b) Additional filings. If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may submit a GCA filing to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent ($0.01) per Mcf or Dth.

(c) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.

(d) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.

(e) ~~Price volatility risk management costs (~~Financial gas commodity hedging~~)~~. Costs related to gas price volatility risk management through financial hedging for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4608.

(f) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

GCA = (current gas cost + deferred gas cost) - (base gas cost).

(g) Gas price risk management plan. The calculation of the GCA shall be subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs in accordance with the utility's gas price risk management plan as approved by the Commission. Prudently incurred costs above the maximum cap shall be recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs, as determined by the Commission. Collections at the minimum threshold shall be recorded in a reserve fund, not to exceed an amount established by the Commission, and shall be used to offset any deferred balance of prudently incurred costs above the maximum cap.

4604. Contents of GCA Filings.

(a) A GCA filing shall meet the following requirements.

(I) Every GCA filing shall contain attachments 1 through 9. The attachments shall meet the requirements set out in this rule.

(II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.

(III) Attachments 2, 3, 5, and 6 shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(IV) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application. Work-papers shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(V) The filing shall cross-reference the proceeding numbers of the associated GPP submittals.

(VI) An explanation of all pro forma adjustments shall be provided, if applicable.

(b) GCA attachment No. 1 - GCA summary. This attachment shall clearly illustrate all of the following principles.

(I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis.

(II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis; and

(III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.

(c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity. The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP, as required pursuant to rule 4606.

(I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil ($0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

(II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.

(d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs, the calculation of deferred gas cost, the implementation of the utility's GPRMP, and the calculation of the GPIM symmetric sharing amounts, as approved by the Commission. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, GPIM ~~performance results~~sharing amounts, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity for the next 12-month period. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its GCA filings, the utility shall reflect actual deferred costs for the most recent period, or as otherwise approved by the Commission.~~ The results of the GPIM sharing shall be calculated on an annual basis and included in the deferred balance.~~

(e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently effective rates for sales gas service and, where applicable, gas transportation service.

(f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:

(I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and

(II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.

(g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:

(I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and

(II) derive the amount of the GCA applied to each specific sales gas customer class, subject to the utility's GPRMP and GPIM, and, where applicable, gas transportation customer rate classes.

(h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:

(I) current and proposed GCA rates and percentage change;

(II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;

(III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and

(IV) a statement that the utility made a separate gas purchase report filing in accordance with rule 4608 to begin the initial prudence review evaluation process for the prior gas purchase year.

(i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.

(j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.

(k) GCA attachment No. 10 - GPIM sharing amounts. As applicable, this attachment shall detail the calculation of GPIM sharing amounts per rule 4607 and any sharing amounts included in the deferred gas cost calculation presented in attachment No. 3. The calculation of the sharing amounts shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

4605. Gas Purchase Plans.

(a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

(b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:

(I) the information required by rule 4606;

(II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;

(III) the utility's forecasted pricing for each receipt point/area; and

(IV) the utility's portfolio management plan.

(c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.

(d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.

(e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.

(f) Modified GPP. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

4606. Contents of the GPP.

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

(b) GPP attachment No. 2 - gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.

(c) GPP attachment No. 3 - portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy

for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.

(d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:

(I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand.

(II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.

(III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.

(IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

4607. Gas Performance Incentive Mechanism ~~Applications~~.

In conjunction with its GPRMP, the utility shall implement a GPIM in accordance with this rule and the specific terms set forth in its GCA tariff sheets. The utility shall implement a GPIM for each GCA rate area with more than 50,000 full service customers or each purchasing region as specified in the utility's GPP.

(a) An ~~GPIM~~ application to establish a GPIM for a utility with more than 50,000 but less than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (~~a~~I) through (~~d~~IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(~~a~~I) GPIM benchmark. Methodology to establish the GPIM benchmark for commodity gas purchases based on verifiable, reported market indices, with a reasonable adjustment, and for appropriate locations.

(~~b~~II) GPIM commodity gas volumes. Description and explanation of all gas volumes to be included in the GPIM.

(~~I~~A) The volumes and costs associated with fixed-price, long-term supply contracts may be excluded from the GPIM and risk sharing calculation.

(~~II~~B) The volumes and costs associated with storage injections and withdrawals, including both physical and contract storage, may be excluded from the GPIM and risk sharing calculation. Utilities shall provide a description of storage assets to be either included or excluded from the GPIM.

(~~III~~C) The volumes and costs associated with associated with financial hedging shall be excluded from the GPIM and risk sharing calculation.

(~~IV~~D) All other actual gas volumes and costs shall be subject to the GPIM with consideration of reasonable adjustments as determined by the Commission.

(~~c~~III) Upstream supply costs. Description and explanation of upstream costs included in the GPIM risk sharing mechanism, including the methodology for developing an appropriate benchmark for such costs, if appropriate.

(~~d~~IV) Risk sharing amount. Methodology for calculating the risk sharing amount.

(~~I~~A) A formula will calculate a percentage of the difference between the actual gas costs and the benchmark formula for applicable gas volumes, either positive or negative, borne or retained by the utility, subject to applicable limitations.

(~~II~~B) The utility shall explain:

(~~A~~i) any proposed deadband around the GPIM benchmark whereby price variation within the deadband is excluded from risk sharing formula;

(~~B~~ii) any proposed cap or floor on the results of the risk sharing; and

(~~C~~iii) any proposed methodology for applying force majeure or similar provisions to the risk sharing mechanism.

(~~III~~C) Backcasting analysis, based on a minimum of the most recent three years of historical data, will demonstrate how the proposed GPIM benchmark would have been calculated and how the proposed risk sharing mechanism would have performed over the historical period. This analysis shall assume the utility made no changes to its actions in response to the mechanism and ignore any force majeure or similar events. The utility may, in its discretion, present additional analysis.

~~(e) Review for continuation of the GPIM. The utility may request that the Commission determine whether its GPIM should be discontinued based on prior performance. A comprehensive assessment of the GPIM shall be required no later than January 1, 2030.~~

(b) An application to establish a GPIM for a utility with more than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (I) through (IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(I) GPIM benchmark gas rate. The GPIM benchmark gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the average of the GPIM total gas cost for that same quarter in the previous three years divided by the GPIM total gas quantity for the same quarters in the previous three years.

(II) GPIM actual gas rate. The GPIM actual gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that quarter divided by the GPIM total gas quantity for that same quarter.

(III) GPIM sharing amount. The GPIM sharing amount will be calculated as four percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate, either positive or negative, multiplied by the GPIM total gas quantity for the completed calendar quarter preceding the GCA filing, subject to the following limitations:

(A) the GPIM sharing amount for a quarter shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth;

(B) the GPIM sharing amount for a quarter shall be the difference between the GPIM benchmark gas rate and the GPIM actual gas rate that is above or below the $0.50 per Mcf or Dth threshold in subparagraph 4607(b)(III)(A); and

(C) the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

(IV) The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception may allow the utility to exclude costs from the GPIM that are deemed to be either associated with the force majeure event as defined by the utility's tariffs on file with the Commission or associated with force majeure events as defined in the utility's upstream gas supply, storage, and transportation agreements and tariffs.

(c) Unless subject to the limitations in subparagraph 4607(a)(IV)(B)(ii) or subparagraph 4607(b)(III)(C), the GPIM sharing amount shall be accounted for in the utility's deferred gas cost calculation for the quarterly GCA filing.

(I) To the extent a GCA calculation is subject to a maximum cap specified in a utility's GPRMP, any new positive GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to a carryforward into subsequent GCA quarterly filings. The carried forward GPIM amount shall be eligible to offset incurred negative GPIM sharing amounts.

(II) To the extent a GCA calculation is subject to a minimum threshold specified in a utility's GPRMP, any new negative GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be accounted for in the deferred gas cost calculation in subsequent quarterly GCA filings in which the GCA calculation is above the minimum threshold.

4608. Gas Purchase and Deferred Balance Reports and Prudence Reviews.

(a) GPDBR filing requirements. The utility shall file a GPDBR in accordance with paragraph 4602(e) for the review and approval of the calculation of the deferred GCA balance ~~and~~ including the implementation of the utility's GPIM, as applicable, ~~performance and sharing amount~~ for the previous four quarters ending June 30. The GPDBR shall be filed under the previous year's GPP proceeding number (filed approximately 15 months previously). Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPDBR filing.

(b) Prudence review process. Based on the initial evaluation of the GPDBR, including the results of ~~any active~~the GPIM, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GDBPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

(c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action). The Commission may consider, as appropriate, whether the utility employed carefulness, precaution, attentiveness, and good judgment.

~~(d) GPIM shared savings. A utility may request approval of any shared savings amounts under its GPIM based upon a review of the drivers of the sharing amounts and the appropriateness of the sharing amounts.~~

(~~e~~d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

(~~f~~e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

4609. Contents of the GPDBR.

A GPDBR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA filing pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work-papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPDBR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year. Each gas utility shall provide a description and explanation of the following:

(I) the volumes and costs associated with fixed-price, long-term supply contracts;

(II) the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and

(III) the volumes and costs associated with financial hedging.

(b) GPDBR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.

(c) GPDBR attachment No. 3 - actual portfolio purchases. This attachment shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4608(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.

(d) GPDBR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

(I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;

(II) an itemized listing of the specific costs the utility incurred to purchase upstream services;

(III) actual peak day demand experienced by the utility during the gas purchase year; and

(IV) an itemized list of capacity release volumes and revenues.

(e) GPDBR attachment No. 5 - deferred balances. This attachment shall provide monthly deferred balances for the 12 months ending June 30.

(f) GPDBR attachment No. 6 - GPIM results. This attachment shall provide, for the 12 months ending June 30:

(I) the ~~monthly~~ quarterly GPIM benchmark ~~calculation~~ gas rates and GPIM actual gas rates~~including market indices used in the formulation~~;~~ and~~

(II) the quarterly and twelve-month cumulative GPIM ~~risk~~ sharing ~~calculation including application of any applicable deadband, cap or floor~~amounts~~.~~; and

(III) the calculation of the applicable cap ~~pursuant to subparagraph 4607(c)(II)~~on GPIM sharing amounts.

4610. Confidentiality.

(a) For each attachment filed by the utility as confidential under rules 4600 through 4610, the utility shall provide, at a minimum, a version of the attachment with publicly available information.

(b) The Office of the Utility Consumer Advocate (UCA) may provide each utility annually, on or before January 1 of each year, an executed generic nondisclosure agreement with the utility so that the utility shall provide such confidential information to the UCA when any utility filings are made pursuant to rules 4600 through 4609 for the subsequent year.

4611. – 4699. [Reserved].

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

GAS COST ADJUSTMENT, PRUDENCE REVIEW, AND PERFORMANCE INCENTIVE

4600. Overview and Purpose.

Rules 4601 through 4610 are used by utilities to revise gas rates on an expedited basis, to reduce the volatility of gas costs for customers, and to improve their management of gas costs. These rules provide instructions for the filing of: gas cost adjustment filings; annual gas purchase plan submittals; annual gas purchase and deferred balance reports; gas price risk mitigation plans; and gas performance incentive mechanisms. The purpose of the Gas Cost Adjustment is to enable utilities, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the utility's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase and Deferred Balance Report is to present the utility's actual purchases of gas commodity and upstream services during each month of the gas purchase year. The combined purpose of the Gas Price Risk Management Plan and the Gas Performance Incentive Mechanism is to address the volatility of gas commodity costs recovered from the utility's customers and to align the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs.

4601. Definitions.

The following definitions apply to rules 4600 through 4610 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Account No. 191" means an account under the Federal Energy Regulatory Commission Uniform System of Accounts (USOA) used to account for the difference between purchased gas costs and revenues collected by a utility's gas cost adjustment.

(b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.

(c) "Base rates" means the utility's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

(d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.

(e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.

(f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.

(g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals, approved hedging program costs, and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.

(h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.

(i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.

(j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.

(k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.

(l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.

(m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.

(n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.

(o) "GCA filing" means an application or advice letter filing to adjust the GCA rate.

(p) "GCA rate area" means the geographic portion of the utility's service area in which a GCA rate is calculated and billed to customers. A utility may have a single GCA rate area that covers its entire service area or multiple GCA rate areas as established by the Commission.

(q) "Gas performance incentive mechanism" (GPIM) means an incentive mechanism implemented in conjunction with a GPRMP that aligns the utility’s financial incentives with the financial interests of its customers regarding incurred gas commodity costs.

(r) “GPIM total gas costs” means the utility’s incurred expenditures on gas commodity for applicable sales gas rate schedules in each past calendar quarter calculated in accordance with the utility’s GCA tariff sheets on file with the Commission.

(s) “GPIM total gas quantity” means the quantity of gas commodity purchased (Mcf or Dth) for applicable sales gas rate schedules for each past calendar quarter calculated in accordance with the utility’s GCA tariff sheets on file with the Commission.

(t) “Gas price risk management plan” (GPRMP) means a plan governing the calculation of the GCA subject to a maximum cap and a minimum threshold pursuant to paragraph 4603(g).

(u) "Gas purchase and deferred balance report" (GPDBR) means a report pursuant to rule 4608 which is filed with the Commission and which describes the utility’s actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

(v) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility’s planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.

(w) "Gas purchase year" means a 12-month period from July 1 through June 30.

(x) "Gas transportation service" means the delivery of gas commodity on the utility’s pipeline system (either transmission or distribution) pursuant to any of the utility’s gas transportation rate schedules on file with the Commission.

(y) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).

(z) "Long-term contract" means a firm, fixed-price supply contract with an initial term of 12 months of more in duration.

(aa) "Mil" means one-tenth of one cent ($0.001).

(bb) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.

(cc) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility’s system.

(dd) "Propane utility" means a public utility as defined in § 40-1-103, C.R.S., that operates for the purpose of supplying the public propane but does not supply natural gas or other fuels.

(ee) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.

(ff) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.

(gg) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.

(hh) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

4602. Schedule for Filings by Utilities.

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule.

(a) Utilities with more than 50,000 full service customers shall file with the Commission quarterly GCA filings. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(b) Utilities with fewer than 50,000 full service customers shall file with the Commission either quarterly GCA filings or two GCA filings per year with effective dates for GCA rates of November 1 and April 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(c) Propane utilities shall file an annual GCA filing with an effective date of November 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(d) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

(e) The GPDBR for the preceding gas purchase year in which a GPP was filed shall be filed annually by October 1.

(f) All utilities, except for propane utilities, shall implement a GPRMP through their GCA filings. Modifications to a GPRMP shall be accomplished through an application filing separate from a GCA filing.

(g) Utilities with fewer than 50,000 full service customers and propane utilities are not required to include a GPIM in their GCA tariff sheets pursuant to rule 4607.

(h) Utilities with more than 50,000 full service customers shall file an application to include a GPIM within their GCA tariff sheets pursuant to rule 4607 within 60 days of the effective date of these rules. The initial GPIM for utilities with more than 50,000 but less than 500,000 full service customers shall be established in accordance with paragraph 4607(a). The initial GPIM for utilities with more than 500,000 full service customers shall be established in accordance with paragraph 4607(b). Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing.

(i) No later than 90 days after the conclusion of a full heating season covered by the utility's initial GPIM, the utility shall file an application for the renewal of the GPIM. Implementation of the initial GPIM shall continue until the renewed GPIM goes into effect. For the utilities with an initial GPIM based on the framework set forth in paragraph 4607(a), the renewal application shall present an analysis of the implementation of the utility's initial GPIM as approved by the Commission and an analysis of GPIM benchmark gas rate and GPIM sharing amount in paragraph 4607(b) as if they had instead been implemented over the same period as the initial GPIM. The utility may propose to implement a modified GPIM provided that the Commission determines the modified GPIM comports with the requirements of § 40-3-120, C.R.S.

4603. Gas Cost Adjustments.

(a) Scheduled filings. A utility shall submit a GCA filing to adjust its GCA. The GCA filing shall be filed pursuant to the schedule provided in rule 4602. The GCA filing shall be submitted not less than two weeks in advance of the proposed effective date.

(b) Additional filings. If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may submit a GCA filing to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent ($0.01) per Mcf or Dth.

(c) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.

(d) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.

(e) Financial gas commodity hedging. Costs related to gas price volatility risk management through financial hedging for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4608.

(f) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

GCA = (current gas cost + deferred gas cost) - (base gas cost).

(g) Gas price risk management plan. The calculation of the GCA shall be subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs in accordance with the utility's gas price risk management plan as approved by the Commission. Prudently incurred costs above the maximum cap shall be recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs, as determined by the Commission. Collections at the minimum threshold shall be recorded in a reserve fund, not to exceed an amount established by the Commission, and shall be used to offset any deferred balance of prudently incurred costs above the maximum cap.

4604. Contents of GCA Filings.

(a) A GCA filing shall meet the following requirements.

(I) Every GCA filing shall contain attachments 1 through 9. The attachments shall meet the requirements set out in this rule.

(II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.

(III) Attachments 2, 3, 5, and 6 shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(IV) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application. Work-papers shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(V) The filing shall cross-reference the proceeding numbers of the associated GPP submittals.

(VI) An explanation of all pro forma adjustments shall be provided, if applicable.

(b) GCA attachment No. 1 - GCA summary. This attachment shall clearly illustrate all of the following principles.

(I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis.

(II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis; and

(III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.

(c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity. The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP, as required pursuant to rule 4606.

(I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil ($0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

(II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.

(d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs, the calculation of deferred gas cost, the implementation of the utility's GPRMP, and the calculation of the GPIM symmetric sharing amounts, as approved by the Commission. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, GPIM sharing amounts, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity for the next 12-month period. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its GCA filings, the utility shall reflect actual deferred costs for the most recent period, or as otherwise approved by the Commission.

(e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently effective rates for sales gas service and, where applicable, gas transportation service.

(f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:

(I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and

(II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.

(g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:

(I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and

(II) derive the amount of the GCA applied to each specific sales gas customer class, subject to the utility's GPRMP and GPIM, and, where applicable, gas transportation customer rate classes.

(h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:

(I) current and proposed GCA rates and percentage change;

(II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;

(III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and

(IV) a statement that the utility made a separate gas purchase report filing in accordance with rule 4608 to begin the initial prudence review evaluation process for the prior gas purchase year.

(i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.

(j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.

(k) GCA attachment No. 10 - GPIM sharing amounts. As applicable, this attachment shall detail the calculation of GPIM sharing amounts per rule 4607 and any sharing amounts included in the deferred gas cost calculation presented in attachment No. 3. The calculation of the sharing amounts shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

4605. Gas Purchase Plans.

(a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

(b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:

(I) the information required by rule 4606;

(II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;

(III) the utility's forecasted pricing for each receipt point/area; and

(IV) the utility's portfolio management plan.

(c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.

(d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.

(e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.

(f) Modified GPP. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

4606. Contents of the GPP.

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

(b) GPP attachment No. 2 - gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.

(c) GPP attachment No. 3 - portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.

(d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:

(I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand.

(II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.

(III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.

(IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

4607. Gas Performance Incentive Mechanism.

In conjunction with its GPRMP, the utility shall implement a GPIM in accordance with this rule and the specific terms set forth in its GCA tariff sheets. The utility shall implement a GPIM for each GCA rate area with more than 50,000 full service customers or each purchasing region as specified in the utility's GPP.

(a) An application to establish a GPIM for a utility with more than 50,000 but less than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (I) through (IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(I) GPIM benchmark. Methodology to establish the GPIM benchmark for commodity gas purchases based on verifiable, reported market indices, with a reasonable adjustment, and for appropriate locations.

(II) GPIM commodity gas volumes. Description and explanation of all gas volumes to be included in the GPIM.

(A) The volumes and costs associated with fixed-price, long-term supply contracts may be excluded from the GPIM and risk sharing calculation.

(B) The volumes and costs associated with storage injections and withdrawals, including both physical and contract storage, may be excluded from the GPIM and risk sharing calculation. Utilities shall provide a description of storage assets to be either included or excluded from the GPIM.

(C) The volumes and costs associated with associated with financial hedging shall be excluded from the GPIM and risk sharing calculation.

(D) All other actual gas volumes and costs shall be subject to the GPIM with consideration of reasonable adjustments as determined by the Commission.

(III) Upstream supply costs. Description and explanation of upstream costs included in the GPIM risk sharing mechanism, including the methodology for developing an appropriate benchmark for such costs, if appropriate.

(IV) Risk sharing amount. Methodology for calculating the risk sharing amount.

(A) A formula will calculate a percentage of the difference between the actual gas costs and the benchmark formula for applicable gas volumes, either positive or negative, borne or retained by the utility, subject to applicable limitations.

(B) The utility shall explain:

(i) any proposed deadband around the GPIM benchmark whereby price variation within the deadband is excluded from risk sharing formula;

(ii) any proposed cap or floor on the results of the risk sharing; and

(iii) any proposed methodology for applying force majeure or similar provisions to the risk sharing mechanism.

(C) Backcasting analysis, based on a minimum of the most recent three years of historical data, will demonstrate how the proposed GPIM benchmark would have been calculated and how the proposed risk sharing mechanism would have performed over the historical period. This analysis shall assume the utility made no changes to its actions in response to the mechanism and ignore any force majeure or similar events. The utility may, in its discretion, present additional analysis.

(b) An application to establish a GPIM for a utility with more than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (I) through (IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(I) GPIM benchmark gas rate. The GPIM benchmark gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the average of the GPIM total gas cost for that same quarter in the previous three years divided by the GPIM total gas quantity for the same quarters in the previous three years.

(II) GPIM actual gas rate. The GPIM actual gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that quarter divided by the GPIM total gas quantity for that same quarter.

(III) GPIM sharing amount. The GPIM sharing amount will be calculated as four percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate, either positive or negative, multiplied by the GPIM total gas quantity for the completed calendar quarter preceding the GCA filing, subject to the following limitations:

(A) the GPIM sharing amount for a quarter shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth;

(B) the GPIM sharing amount for a quarter shall be the difference between the GPIM benchmark gas rate and the GPIM actual gas rate that is above or below the $0.50 per Mcf or Dth threshold in subparagraph 4607(b)(III)(A); and

(C) the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

(IV) The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception may allow the utility to exclude costs from the GPIM that are deemed to be either associated with the force majeure event as defined by the utility's tariffs on file with the Commission or associated with force majeure events as defined in the utility's upstream gas supply, storage, and transportation agreements and tariffs.

(c) Unless subject to the limitations in subparagraph 4607(a)(IV)(B)(ii) or subparagraph 4607(b)(III)(C), the GPIM sharing amount shall be accounted for in the utility's deferred gas cost calculation for the quarterly GCA filing.

(I) To the extent a GCA calculation is subject to a maximum cap specified in a utility's GPRMP, any new positive GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to a carryforward into subsequent GCA quarterly filings. The carried forward GPIM amount shall be eligible to offset incurred negative GPIM sharing amounts.

(II) To the extent a GCA calculation is subject to a minimum threshold specified in a utility's GPRMP, any new negative GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be accounted for in the deferred gas cost calculation in subsequent quarterly GCA filings in which the GCA calculation is above the minimum threshold.

4608. Gas Purchase and Deferred Balance Reports and Prudence Reviews.

(a) GPDBR filing requirements. The utility shall file a GPDBR in accordance with paragraph 4602(e) for the review and approval of the calculation of the deferred GCA balance including the implementation of the utility's GPIM, as applicable, for the previous four quarters ending June 30. The GPDBR shall be filed under the previous year's GPP proceeding number (filed approximately 15 months previously). Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPDBR filing.

(b) Prudence review process. Based on the initial evaluation of the GPDBR, including the results of the GPIM, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GDBPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

(c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action). The Commission may consider, as appropriate, whether the utility employed carefulness, precaution, attentiveness, and good judgment.

(d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

(e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

4609. Contents of the GPDBR.

A GPDBR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA filing pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work-papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPDBR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year. Each gas utility shall provide a description and explanation of the following:

(I) the volumes and costs associated with fixed-price, long-term supply contracts;

(II) the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and

(III) the volumes and costs associated with financial hedging.

(b) GPDBR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.

(c) GPDBR attachment No. 3 - actual portfolio purchases. This attachment shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4608(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.

(d) GPDBR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

(I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;

(II) an itemized listing of the specific costs the utility incurred to purchase upstream services;

(III) actual peak day demand experienced by the utility during the gas purchase year; and

(IV) an itemized list of capacity release volumes and revenues.

(e) GPDBR attachment No. 5 - deferred balances. This attachment shall provide monthly deferred balances for the 12 months ending June 30.

(f) GPDBR attachment No. 6 - GPIM results. This attachment shall provide, for the 12 months ending June 30:

(I) the quarterly GPIM benchmark gas rates and GPIM actual gas rates;

(II) the quarterly and twelve-month cumulative GPIM sharing amounts; and

(III) the calculation of the applicable cap on GPIM sharing amounts.

4610. Confidentiality.

(a) For each attachment filed by the utility as confidential under rules 4600 through 4610, the utility shall provide, at a minimum, a version of the attachment with publicly available information.

(b) The Office of the Utility Consumer Advocate (UCA) may provide each utility annually, on or before January 1 of each year, an executed generic nondisclosure agreement with the utility so that the utility shall provide such confidential information to the UCA when any utility filings are made pursuant to rules 4600 through 4609 for the subsequent year.

4611. – 4699. [Reserved].

Decision No. C25-0132

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.

COMMISSION DECISION DENYING APPLICATION FOR REHEARING, REARGUMENT, OR RECONSIDERATION

Issued Date: February 25, 2025
Adopted Date: February 19, 2025

I. BY THE COMMISSION

A. Statement

1. On April 30, 2024, the Colorado Public Utilities Commission issued a 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. Specifically, the proposed amendments to the Gas Rules attached to the NOPR would continue the utilities' implementation of gas risk management plans and would 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. The NOPR also designated Chairman Eric Blank as Hearing Commissioner, pursuant to § 40-6-101(2)(a), C.R.S., for this rulemaking proceeding.

2. By Decision No. R24-0682 ("Recommended Decision"), issued on September 23, 2024, Hearing Commissioner Blank adopted amendments and additions to the Gas Rules governing the Gas Cost Adjustment ("GCA" or "GCA Rules"), set forth in the Gas Rules at 4 CCR 723-4-4600 through 4610.

3. By Decision No. C25-0005, issued on January 6, 2025, the Commission addressed the exceptions to the Recommended Decision and adopted, with modifications, the rules established by the Recommended Decision.

4. On January 27, 2025, Public Service Company of Colorado ("Public Service" or the "Company") filed an Application for Rehearing, Reargument, or Reconsideration ("Application for RRR") to Decision No. C25-0005. Public Service requests that the Commission further revise the baseline used in the GPIM applicable to the Company from a three-year historical average measure to a current market measure. Public Service also asks the Commission to reset the maximum penalty or incentive caused the new GPIM to be a quarterly limit instead of an annual cap.

5. By this Decision, consistent with the discussion below, we deny Public Service's Application for RRR.

B. Gas Performance Incentive Mechanism

6. Paragraph 4607(b) in the rules adopted by Decision No. C25-0005 sets forth the new symmetric sharing mechanism contemplated in § 40-3-120(2), C.R.S., as applicable to Public Service.

7. The GPIM benchmark gas rate defined in subparagraph 4607(b)(I) equals the average of the GPIM total gas cost for a given quarter in the previous three years divided by the GPIM total gas quantity for the same quarters in the previous three years. Subparagraph 4607(b)(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. Subparagraph 4607(b)(III) then defines the GPIM sharing amount to be four percent of the difference between the two rates defined in the previous two subparagraphs of the proposed rule multiplied by the actual total gas quantity purchased.

8. In its Application for RRR, Public Service states that it has continued concerns with a historical baseline, and requests that a benchmark comparing real-time purchases against published monthly prices as reported in industry trade publications, which it asserts is indicative of current market indices, be adopted instead of the three-year average set forth in subparagraph 4607(b)(I). Additionally, Public Service states it does not have an ability to influence the market, and it is not appropriate to subject the Company to a different benchmark in the Gas Rules than that applicable to the other investor-owned gas utilities ("LDCs") in Colorado.[1] The Company requests that it and the other LDCs should be treated in a consistent manner. Otherwise, Public Service believes the adopted rules will be unlawfully discriminatory.

9. Public Service also takes aim at the justification for treating it differently than the other LDCs. In Decision No. C25-00005, the Commission noted that SB 23-291 directs the Commission to take into consideration the different sizes and ability of the utilities to implement the symmetrical incentive mechanism. And, in light of the concerns about unintended

[1] Colorado Natural Gas, Inc. is excluded from the GPIM requirements by provisions in Rule 4607 as adopted by Decision No. C25-0005, whereas Black Hills Colorado Gas, Inc. and Atmos Energy Corporation are subject to the GPIM requirements set forth in paragraph 4607(a).

consequences raised by the utilities, the Commission decided to take a slower, more deliberate approach to rolling out the GPIM by applying the historical baseline only to utilities with more than 500,000 customers. Public Service argues that this approach is unclear, without a substantive rationale for treating the Company differently than the other gas utilities. Public Service asserts that to the extent the Commission believes that the Company's size means that it can influence the natural gas spot market, the Commission is incorrect. Public Service argues that no Colorado investor-owned gas utility can influence the gas commodity market, and that its size relative to the other utilities does not mean it has enhanced ability to implement the GPIM better than those utilities. Public Service therefore argues that all three Colorado gas utilities with more than 50,000 customers should operate under the same market-based benchmark.

10. Public Service raises four arguments in its Application for RRR contesting the adopted rules as unlawful. First, Public Service argues that there was no notice that the Company or any of the gas utilities would be treated differently than any of the others. Second, the Company argues that nothing in the record supports treating Public Service differently from the other utilities. Third, the Company argues that treating Public Service differently from the other utilities is unlawfully discriminatory under § 40-3-106(1), C.R.S. and certain case law. Fourth, Public Service argues that the adopted rules conflict with the SB 23-291 because they do not protect customers or "improve the utility's management of fuel costs."

11. Public Service ultimately requests that: "Rules 4602(h)[2] and 4607(a) and (b) be revised to delete the un-noticed additional language that is not supported by the record and that

[2] Paragraph 3602(h) cross-references the disputed provisions in paragraphs 3607(a) and 3607(b). "The initial GPIM for utilities with more than 50,000 but less than 500,000 full service customers shall be established in accordance with paragraph 4607(a). The initial GPIM for utilities with more than 500,000 full service customers shall be established in accordance with paragraph 4607(b). Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing."

would create disparate and preferential regulatory treatment for certain Colorado LDCs, that unduly discriminates against Public Service."

12. The Commission's ability to adopt different GPIMs for different utilities is affirmed by § 40-3-120(2)(b), C.R.S., the statute that directs us to undertake this rulemaking. Although Public Service contends that no evidence supports different regulatory treatment for itself, that statute requires the Commission to "tailor the mechanisms to apply to different utilities based on a utility's size or ability to implement the mechanisms." In our view, Public Service's larger sales volume potentially gives the Company more market leverage to implement alternative hedging and other mechanisms that may not be as readily available to smaller gas utilities, but once demonstrated could be extended. Likewise, Public Service has a larger sales and employee base to spread the fixed costs of developing new approaches in ways that the smaller utilities may not.

13. Public Service's contention that the adoption of the provisions in GCA Rules applicable to the Company is unlawfully discriminatory under § 40-3-102 and -106, C.R.S., is also unpersuasive. The case law Public Service cites hold that the Commission cannot approve rates that discriminate between groups of <u>customers</u>. Critically, none of the cases address regulations that treat utilities differently. Furthermore, Public Service fails to provide support for its theory that the Commission cannot promulgate regulations that treat different utilities differently.

14. With respect to notice, Public Service alleges that the NOPR fell short of the requirement in the Administrative Procedure Act that a NOPR state "either the terms or the substance of the proposed rule or a description of the subjects and issues involved." In making this argument Public Service overlooks that the NOPR repeated the provision in SB 23-291 directing the Commission to consider tailoring these rules based on utility size. The NOPR also highlighted

both how Atmos Energy Corporation argued for utility-specific GPIMs, and how Colorado Natural Gas, Inc. approved of the Commission's proposal to exclude utilities with fewer than 50,000 customers. In sum, the NOPR provided the terms, the substance, and a description of the issues involved.

15. Finally, we note, and as also explained in the Recommended Decision, that SB 23-0291 was enacted when a GPIM based on price indices was in place in the GCA Rules applicable to Public Service and yet the legislation required the Commission to conduct this new rulemaking to "establish mechanisms to align the financial incentives of an investor-owned electric or gas utility with the interests of the utility's customers regarding incurred fuel costs." This particular provision in SB 23-291 was a direct response to the sustained gas price increases during the last nine months of 2022, prompting legislators to address the frustration experienced by gas utility customers through very large and unpredictable bill increases, whereas the utilities were essentially held harmless financially.

16. Public Service may wish this Commission had developed more prescriptive rules for its management of fuel costs. But these rules are designed to provide an incentive for LDCs, including Public Service, to develop approaches to improve the utility's management of fuel costs. As a sophisticated company that engages the markets for natural gas, Public Service is well equipped to develop tailored approaches to do so. We reference some potential options for Public Service in Paragraph 12 of this Decision.

17. We therefore conclude that paragraph 4607(b) in the rules adopted by Decision No. C25-0005 properly fulfills the purpose of SB 23-291, aligning utility and customer incentives such that if there were large future changes in gas commodity prices, Public Service would do better financially, to a modest extent, when its customers did better financially, and vice versa.

C. Maximum Sharing Amount

18. Subparagraph 4607(b)(III)(C) sets a cap on aggregate GPIM sharing amounts for Public Service at an amount equal to a 30 basis point pre-tax return on the equity share of the utility's rate base determined on a twelve-month rolling basis.

19. In its Application for RRR, Public Service largely repeats its arguments raised in exceptions to the Recommended Decision that set the GPIM cap at an amount equal to the equity portion of a 30 basis point return on the utility's rate base, measured on a 12-month rolling basis. Public Service asks that the 30 basis points instead be divided by 4 and the maximum sharing amounts be applied as a "firm cap" each calendar quarter.

20. In its Application for RRR, Public Service demonstrates how the "rolling-off" of penalties from previous quarters could result in incurred penalties or incentives being higher than the simple calculation of the equity portion of a 30 basis point return on its rate base, or roughly $5 million.

21. Public Service argues that a quarterly cap set at 7.5 basis points, or $1.25 million per quarter, will prevents quarter-over-quarter "flips" to have a cumulative impact exceeding the 30 basis point figure. Public Service also argues that a quarterly cap "allows for participation of all quarters" whereas the rolling average cap could cause quarters subsequent to capped levels not to accrue. Public Service further argues that the quarterly cap better aligns with the intent of the GPIM sharing mechanism and the cadence of GCA filings.

22. As an alternative to the 7.5 basis point quarterly cap, Public Service proposes a weighted quarterly cap to address the seasonality of gas purchases (and hence the seasonality of GPIM penalties or incentives) as addressed by the Commission in Decision No. C25-0005. Public Service suggests that the 30 basis points could be apportioned across the four quarters based

on purchase quantities. Public Service suggests that the apportionment could be reset each year based on purchased quantities reflected in its Gas Purchase and Deferred Balance Report. Public Service states that this would retain the 30-basis point "annual cap" but would implement it in a way that the highest caps on incentives or penalties would apply in the first and fourth quarters of each year (*i.e.*, the highest caps would apply in the heating season months).

23. We deny Public Service's request to modify the cap on the GPIM incentives or penalties established by subparagraph 4607(b)(III)(C). We are unpersuaded by Public Service's presentation of how the rolling-average approach in the adopted rules will result in an unintended maximum incentive or penalty resulting from the implementation of the GPIM. We continue to uphold the Recommended Decision that states: "This revised cap level is reasonable in that it preserves the intended alignment between the utility's financial experience to the customer's experience in paying the GCA while not unduly affecting the utility's overall financial risk."

II. ORDER

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration of Decision No. C25-0005, filed by Public Service Company of Colorado on January 27, 2025, is denied, consistent with the discussion above.

2. The Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* 723-4, contained in legislative format in Attachment A to this Decision and final format in Attachment B to this Decision, are adopted. The attachments are publicly 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

3. The Opinion of the Attorney General of the state of Colorado shall be obtained regarding the constitutionality and legality of the rules as finally adopted. 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. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING February 19, 2025.

(S E A L)

STATE OF COLORADO ★ THE PUBLIC UTILITIES COMMISSION ★ NIL SINE NUMINE

ATTEST: A TRUE COPY

Rebecca E White

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

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MEGAN M. GILMAN

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TOM PLANT

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Commissioners

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

GAS COST ADJUSTMENT, PRUDENCE REVIEW, AND PERFORMANCE INCENTIVE

4600. Overview and Purpose.

Rules 4601 through 4610 are used by utilities to revise gas rates on an expedited basis, to reduce the volatility of gas costs for customers, and to improve their management of gas costs. These rules provide instructions for the filing of: gas cost adjustment filings; annual gas purchase plan submittals; annual gas purchase and deferred balance reports; gas price risk mitigation plans; and gas performance incentive mechanisms~~ applications~~. The purpose of the Gas Cost Adjustment is to enable utilities, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the utility's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase and Deferred Balance Report is to present the utility's actual purchases of gas commodity and upstream services during each month of the gas purchase year. The combined purpose of the Gas Price Risk Management Plan and the Gas Performance Incentive Mechanism ~~application~~ is to address the volatility of gas commodity costs recovered from the utility's customers and to align the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs~~propose for review and approval a performance incentive mechanism that establishes a gas cost benchmark and applies a risk sharing mechanism~~.

4601. Definitions.

The following definitions apply to rules 4600 through ~~4609~~ 4610 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Account No. 191" means an account under the Federal Energy Regulatory Commission Uniform System of Accounts (USOA) used to account for the difference between purchased gas costs and revenues collected by a utility's gas cost adjustment.

(b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.

(c) "Base rates" means the utility's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

(d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.

(e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.

(f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.

(g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals, approved hedging program costs, and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.

(h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.

(i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.

(j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.

(k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.

(l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.

(m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.

(n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.

(o) "GCA filing" means an application or advice letter filing to adjust the GCA rate.

(p) "GCA rate area" means the geographic portion of the utility's service area in which a GCA rate is calculated and billed to customers. A utility may have a single GCA rate area that covers its entire service area or multiple GCA rate areas as established by the Commission.

(q) "Gas performance incentive mechanism" (GPIM) means an incentive mechanism implemented in conjunction with a GPRMP that aligns the utility's financial incentives with the financial interests of its customers regarding incurred ~~shares the risk of~~ gas commodity costs ~~between the utility and its customers~~.

~~(r) "GPIM application" means an application pursuant to rule 4607 establishing a GPIM.~~

~~(s) "GPIM benchmark" means a benchmark calculated based on verifiable, reported market indices, with a reasonable adjustment, for comparison with actual commodity costs incurred by the utility.~~

(r) "GPIM total gas costs" means the utility's incurred expenditures on gas commodity for applicable sales gas rate schedules in each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(s) "GPIM total gas quantity" means the quantity of gas commodity purchased (Mcf or Dth) for applicable sales gas rate schedules for each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(t) "Gas price risk management plan" (GPRMP) means a plan governing the calculation of the GCA subject to a maximum cap and a minimum threshold pursuant to paragraph 4603(g).

(~~t~~u) "Gas purchase and deferred balance report" (GPDBR) means a report pursuant to rule 4608 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

(~~u~~v) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.

(~~v~~w) "Gas purchase year" means a 12-month period from July 1 through June 30.

(~~w~~x) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.

(~~x~~y) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).

(~~y~~z) "Long-term contract" means a firm, fixed-price supply contract with an initial term of 12 months of more in duration.

(~~z~~aa) "Mil" means one-tenth of one cent ($0.001).

(~~aa~~bb) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.

(~~bb~~cc) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.

(~~cc~~dd) "Propane utility" means a public utility as defined in § 40-1-103, C.R.S., that operates for the purpose of supplying the public propane but does not supply natural gas or other fuels.

(~~dd~~ee) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.

(~~ee~~ff) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.

(~~ff~~gg) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.

(~~gg~~hh) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

4602. Schedule for Filings by Utilities.

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule.

(a) Utilities with more than 50,000 full service customers shall file with the Commission quarterly GCA filings. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(b) Utilities with fewer than 50,000 full service customers shall file with the Commission either quarterly GCA filings or two GCA filings per year with effective dates for GCA rates of November 1 and April 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(c) Propane utilities shall file an annual GCA filing with an effective date of November 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(d) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

(e) The GPDBR for the preceding gas purchase year in which a GPP was filed shall be filed annually by October 1.

(f) All utilities, except for propane utilities, shall implement a GPRMP through their GCA filings. Modifications to a GPRMP shall be accomplished through an application filing separate from a GCA filing.

(~~f~~g) Utilities with fewer than 50,000 full service customers and propane utilities are not required to ~~file~~ include a GPIM ~~applications~~ in their GCA tariff sheets pursuant to rule 4607.

(~~g~~h) Utilities with more than ~~500,000~~50,000 full service customers shall file an ~~initial GPIM~~ application to include a GPIM within their GCA tariff sheets pursuant to rule 4607 within 60 days of the effective date of these rules ~~in advance of the 2023-2024 hearing season for a period extending through the gas purchase year ending in June 2025. GPIM applications for periods after June 2025 shall be filed pursuant to rule 4607 at least every three years~~. The initial GPIM for utilities with more than 50,000 but less than 500,000 full service customers shall be established in accordance with paragraph 4607(a). The initial GPIM for utilities with more than 500,000 full service customers shall be established in accordance with paragraph 4607(b). Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing.

~~(h) Utilities with more than 50,000 full service customers but fewer than 500,000 full service customers shall file an initial GPIM application pursuant to rule 4607 no later than September 1, 2023 for a period extending through the gas purchase year ending in June 2026. GPIM applications for periods after June 2026 shall be filed pursuant to rule 4607 at least every three years.~~

(i) No later than 90 days after the conclusion of ~~After each~~ a full heating season covered by ~~a~~ the utility's initial GPIM, the utility shall file an ~~report on its performance no later than October 1~~application for the renewal of ~~. Commission staff shall review the report and confer with the utility regarding whether it is appropriate to continue~~ the GPIM. Implementation of the initial GPIM shall continue until the renewed GPIM goes into effect. For the utilities with an initial GPIM based on the framework set forth in paragraph 4607(a), the renewal application shall present an analysis of the implementation of the utility's initial GPIM as approved by the Commission and an analysis of GPIM benchmark gas rate and GPIM sharing amount in paragraph 4607(b) as if they had instead been implemented over the same period as the initial GPIM. The utility may propose to implement a modified GPIM provided that the Commission determines the modified GPIM comports with the requirements of § 40-3-120, C.R.S.

4603. Gas Cost Adjustments.

(a) Scheduled filings. A utility shall submit a GCA filing to adjust its GCA. The GCA filing shall be filed pursuant to the schedule provided in rule 4602. The GCA filing shall be submitted not less than two weeks in advance of the proposed effective date.

(b) Additional filings. If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may submit a GCA filing to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent ($0.01) per Mcf or Dth.

(c) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.

(d) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.

(e) ~~Price volatility risk management costs (~~Financial gas commodity hedging~~)~~. Costs related to gas price volatility risk management through financial hedging for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4608.

(f) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

GCA = (current gas cost + deferred gas cost) - (base gas cost).

(g) Gas price risk management plan. The calculation of the GCA shall be subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs in accordance with the utility's gas price risk management plan as approved by the Commission. Prudently incurred costs above the maximum cap shall be recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs, as determined by the Commission. Collections at the minimum threshold shall be recorded in a reserve fund, not to exceed an amount established by the Commission, and shall be used to offset any deferred balance of prudently incurred costs above the maximum cap.

4604. Contents of GCA Filings.

(a) A GCA filing shall meet the following requirements.

(I) Every GCA filing shall contain attachments 1 through 9. The attachments shall meet the requirements set out in this rule.

(II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.

(III) Attachments 2, 3, 5, and 6 shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(IV) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application. Work-papers shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(V) The filing shall cross-reference the proceeding numbers of the associated GPP submittals.

(VI) An explanation of all pro forma adjustments shall be provided, if applicable.

(b) GCA attachment No. 1 - GCA summary. This attachment shall clearly illustrate all of the following principles.

(I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis.

(II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis; and

(III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.

(c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity. The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP, as required pursuant to rule 4606.

(I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil ($0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

(II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.

(d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs, the calculation of deferred gas cost, the implementation of the utility's GPRMP, and the calculation of the GPIM symmetric sharing amounts, as approved by the Commission. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, GPIM ~~performance results~~sharing amounts, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity for the next 12-month period. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its GCA filings, the utility shall reflect actual deferred costs for the most recent period, or as otherwise approved by the Commission.~~ The results of the GPIM sharing shall be calculated on an annual basis and included in the deferred balance.~~

(e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently effective rates for sales gas service and, where applicable, gas transportation service.

(f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:

(I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and

(II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.

(g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:

(I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and

(II) derive the amount of the GCA applied to each specific sales gas customer class, subject to the utility's GPRMP and GPIM, and, where applicable, gas transportation customer rate classes.

(h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:

(I) current and proposed GCA rates and percentage change;

(II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;

(III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and

(IV) a statement that the utility made a separate gas purchase report filing in accordance with rule 4608 to begin the initial prudence review evaluation process for the prior gas purchase year.

(i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.

(j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.

(k) GCA attachment No. 10 - GPIM sharing amounts. As applicable, this attachment shall detail the calculation of GPIM sharing amounts per rule 4607 and any sharing amounts included in the deferred gas cost calculation presented in attachment No. 3. The calculation of the sharing amounts shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

4605. Gas Purchase Plans.

(a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

(b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:

(I) the information required by rule 4606;

(II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;

(III) the utility's forecasted pricing for each receipt point/area; and

(IV) the utility's portfolio management plan.

(c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.

(d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.

(e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.

(f) Modified GPP. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

4606. Contents of the GPP.

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

(b) GPP attachment No. 2 - gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.

(c) GPP attachment No. 3 - portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy

for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.

(d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:

(I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand.

(II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.

(III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.

(IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

4607. Gas Performance Incentive Mechanism ~~Applications~~.

In conjunction with its GPRMP, the utility shall implement a GPIM in accordance with this rule and the specific terms set forth in its GCA tariff sheets. The utility shall implement a GPIM for each GCA rate area with more than 50,000 full service customers or each purchasing region as specified in the utility's GPP.

(a) An ~~GPIM~~ application to establish a GPIM for a utility with more than 50,000 but less than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (~~a~~I) through (~~d~~IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(~~a~~I) GPIM benchmark. Methodology to establish the GPIM benchmark for commodity gas purchases based on verifiable, reported market indices, with a reasonable adjustment, and for appropriate locations.

(~~b~~II) GPIM commodity gas volumes. Description and explanation of all gas volumes to be included in the GPIM.

(~~I~~A) The volumes and costs associated with fixed-price, long-term supply contracts may be excluded from the GPIM and risk sharing calculation.

(~~II~~B) The volumes and costs associated with storage injections and withdrawals, including both physical and contract storage, may be excluded from the GPIM and risk sharing calculation. Utilities shall provide a description of storage assets to be either included or excluded from the GPIM.

(~~III~~C) The volumes and costs associated with associated with financial hedging shall be excluded from the GPIM and risk sharing calculation.

(~~IV~~D) All other actual gas volumes and costs shall be subject to the GPIM with consideration of reasonable adjustments as determined by the Commission.

(~~c~~III) Upstream supply costs. Description and explanation of upstream costs included in the GPIM risk sharing mechanism, including the methodology for developing an appropriate benchmark for such costs, if appropriate.

(~~d~~IV) Risk sharing amount. Methodology for calculating the risk sharing amount.

(~~I~~A) A formula will calculate a percentage of the difference between the actual gas costs and the benchmark formula for applicable gas volumes, either positive or negative, borne or retained by the utility, subject to applicable limitations.

(~~II~~B) The utility shall explain:

(~~A~~i) any proposed deadband around the GPIM benchmark whereby price variation within the deadband is excluded from risk sharing formula;

(~~B~~ii) any proposed cap or floor on the results of the risk sharing; and

(~~C~~iii) any proposed methodology for applying force majeure or similar provisions to the risk sharing mechanism.

(~~III~~C) Backcasting analysis, based on a minimum of the most recent three years of historical data, will demonstrate how the proposed GPIM benchmark would have been calculated and how the proposed risk sharing mechanism would have performed over the historical period. This analysis shall assume the utility made no changes to its actions in response to the mechanism and ignore any force majeure or similar events. The utility may, in its discretion, present additional analysis.

~~(e) Review for continuation of the GPIM. The utility may request that the Commission determine whether its GPIM should be discontinued based on prior performance. A comprehensive assessment of the GPIM shall be required no later than January 1, 2030.~~

(b) An application to establish a GPIM for a utility with more than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (I) through (IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(I) GPIM benchmark gas rate. The GPIM benchmark gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the average of the GPIM total gas cost for that same quarter in the previous three years divided by the GPIM total gas quantity for the same quarters in the previous three years.

(II) GPIM actual gas rate. The GPIM actual gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that quarter divided by the GPIM total gas quantity for that same quarter.

(III) GPIM sharing amount. The GPIM sharing amount will be calculated as four percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate, either positive or negative, multiplied by the GPIM total gas quantity for the completed calendar quarter preceding the GCA filing, subject to the following limitations:

(A) the GPIM sharing amount for a quarter shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth;

(B) the GPIM sharing amount for a quarter shall be the difference between the GPIM benchmark gas rate and the GPIM actual gas rate that is above or below the $0.50 per Mcf or Dth threshold in subparagraph 4607(b)(III)(A); and

(C) the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

(IV) The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception may allow the utility to exclude costs from the GPIM that are deemed to be either associated with the force majeure event as defined by the utility's tariffs on file with the Commission or associated with force majeure events as defined in the utility's upstream gas supply, storage, and transportation agreements and tariffs.

(c) Unless subject to the limitations in subparagraph 4607(a)(IV)(B)(ii) or subparagraph 4607(b)(III)(C), the GPIM sharing amount shall be accounted for in the utility's deferred gas cost calculation for the quarterly GCA filing.

(I) To the extent a GCA calculation is subject to a maximum cap specified in a utility's GPRMP, any new positive GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to a carryforward into subsequent GCA quarterly filings. The carried forward GPIM amount shall be eligible to offset incurred negative GPIM sharing amounts.

(II) To the extent a GCA calculation is subject to a minimum threshold specified in a utility's GPRMP, any new negative GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be accounted for in the deferred gas cost calculation in subsequent quarterly GCA filings in which the GCA calculation is above the minimum threshold.

4608. Gas Purchase and Deferred Balance Reports and Prudence Reviews.

(a) GPDBR filing requirements. The utility shall file a GPDBR in accordance with paragraph 4602(e) for the review and approval of the calculation of the deferred GCA balance ~~and~~ including the implementation of the utility's GPIM, as applicable, ~~performance and sharing amount~~ for the previous four quarters ending June 30. The GPDBR shall be filed under the previous year's GPP proceeding number (filed approximately 15 months previously). Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPDBR filing.

(b) Prudence review process. Based on the initial evaluation of the GPDBR, including the results of ~~any active~~the GPIM, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GDBPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

(c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action). The Commission may consider, as appropriate, whether the utility employed carefulness, precaution, attentiveness, and good judgment.

~~(d) GPIM shared savings. A utility may request approval of any shared savings amounts under its GPIM based upon a review of the drivers of the sharing amounts and the appropriateness of the sharing amounts.~~

(~~e~~d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

(~~f~~e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

4609. Contents of the GPDBR.

A GPDBR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA filing pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work-papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPDBR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year. Each gas utility shall provide a description and explanation of the following:

(I) the volumes and costs associated with fixed-price, long-term supply contracts;

(II) the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and

(III) the volumes and costs associated with financial hedging.

(b) GPDBR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.

(c) GPDBR attachment No. 3 - actual portfolio purchases. This attachment shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4608(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.

(d) GPDBR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

(I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;

(II) an itemized listing of the specific costs the utility incurred to purchase upstream services;

(III) actual peak day demand experienced by the utility during the gas purchase year; and

(IV) an itemized list of capacity release volumes and revenues.

(e) GPDBR attachment No. 5 - deferred balances. This attachment shall provide monthly deferred balances for the 12 months ending June 30.

(f) GPDBR attachment No. 6 - GPIM results. This attachment shall provide, for the 12 months ending June 30:

(I) the ~~monthly~~ quarterly GPIM benchmark ~~calculation~~ gas rates and GPIM actual gas rates~~including market indices used in the formulation~~;~~ and~~

(II) the quarterly and twelve-month cumulative GPIM ~~risk~~ sharing ~~calculation including application of any applicable deadband, cap or floor~~amounts~~.~~; and

(III) the calculation of the applicable cap ~~pursuant to subparagraph 4607(c)(II)~~on GPIM sharing amounts.

4610. Confidentiality.

(a) For each attachment filed by the utility as confidential under rules 4600 through 4610, the utility shall provide, at a minimum, a version of the attachment with publicly available information.

(b) The Office of the Utility Consumer Advocate (UCA) may provide each utility annually, on or before January 1 of each year, an executed generic nondisclosure agreement with the utility so that the utility shall provide such confidential information to the UCA when any utility filings are made pursuant to rules 4600 through 4609 for the subsequent year.

4611. – 4699. [Reserved].

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

GAS COST ADJUSTMENT, PRUDENCE REVIEW, AND PERFORMANCE INCENTIVE

4600. Overview and Purpose.

Rules 4601 through 4610 are used by utilities to revise gas rates on an expedited basis, to reduce the volatility of gas costs for customers, and to improve their management of gas costs. These rules provide instructions for the filing of: gas cost adjustment filings; annual gas purchase plan submittals; annual gas purchase and deferred balance reports; gas price risk mitigation plans; and gas performance incentive mechanisms. The purpose of the Gas Cost Adjustment is to enable utilities, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the utility's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase and Deferred Balance Report is to present the utility's actual purchases of gas commodity and upstream services during each month of the gas purchase year. The combined purpose of the Gas Price Risk Management Plan and the Gas Performance Incentive Mechanism is to address the volatility of gas commodity costs recovered from the utility's customers and to align the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs.

4601. Definitions.

The following definitions apply to rules 4600 through 4610 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Account No. 191" means an account under the Federal Energy Regulatory Commission Uniform System of Accounts (USOA) used to account for the difference between purchased gas costs and revenues collected by a utility's gas cost adjustment.

(b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.

(c) "Base rates" means the utility's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

(d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.

(e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil ($0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.

(f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.

(g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals, approved hedging program costs, and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.

(h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.

(i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.

(j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.

(k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.

(l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.

(m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.

(n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.

(o) "GCA filing" means an application or advice letter filing to adjust the GCA rate.

(p) "GCA rate area" means the geographic portion of the utility's service area in which a GCA rate is calculated and billed to customers. A utility may have a single GCA rate area that covers its entire service area or multiple GCA rate areas as established by the Commission.

(q) "Gas performance incentive mechanism" (GPIM) means an incentive mechanism implemented in conjunction with a GPRMP that aligns the utility's financial incentives with the financial interests of its customers regarding incurred gas commodity costs.

(r) "GPIM total gas costs" means the utility's incurred expenditures on gas commodity for applicable sales gas rate schedules in each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(s) "GPIM total gas quantity" means the quantity of gas commodity purchased (Mcf or Dth) for applicable sales gas rate schedules for each past calendar quarter calculated in accordance with the utility's GCA tariff sheets on file with the Commission.

(t) "Gas price risk management plan" (GPRMP) means a plan governing the calculation of the GCA subject to a maximum cap and a minimum threshold pursuant to paragraph 4603(g).

(u) "Gas purchase and deferred balance report" (GPDBR) means a report pursuant to rule 4608 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

(v) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.

(w) "Gas purchase year" means a 12-month period from July 1 through June 30.

(x) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.

(y) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).

(z) "Long-term contract" means a firm, fixed-price supply contract with an initial term of 12 months of more in duration.

(aa) "Mil" means one-tenth of one cent ($0.001).

(bb) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.

(cc) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.

(dd) "Propane utility" means a public utility as defined in § 40-1-103, C.R.S., that operates for the purpose of supplying the public propane but does not supply natural gas or other fuels.

(ee) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.

(ff) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.

(gg) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.

(hh) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

4602. Schedule for Filings by Utilities.

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule.

(a) Utilities with more than 50,000 full service customers shall file with the Commission quarterly GCA filings. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(b) Utilities with fewer than 50,000 full service customers shall file with the Commission either quarterly GCA filings or two GCA filings per year with effective dates for GCA rates of November 1 and April 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(c) Propane utilities shall file an annual GCA filing with an effective date of November 1. Additional GCA filings may also be filed as necessary pursuant to paragraph 4603(b).

(d) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

(e) The GPDBR for the preceding gas purchase year in which a GPP was filed shall be filed annually by October 1.

(f) All utilities, except for propane utilities, shall implement a GPRMP through their GCA filings. Modifications to a GPRMP shall be accomplished through an application filing separate from a GCA filing.

(g) Utilities with fewer than 50,000 full service customers and propane utilities are not required to include a GPIM in their GCA tariff sheets pursuant to rule 4607.

(h) Utilities with more than 50,000 full service customers shall file an application to include a GPIM within their GCA tariff sheets pursuant to rule 4607 within 60 days of the effective date of these rules. The initial GPIM for utilities with more than 50,000 but less than 500,000 full service customers shall be established in accordance with paragraph 4607(a). The initial GPIM for utilities with more than 500,000 full service customers shall be established in accordance with paragraph 4607(b). Once established by application, the utility shall implement a GPIM through their GCA filings. Modifications to a GPIM shall be accomplished through an application filing separate from a GCA filing.

(i) No later than 90 days after the conclusion of a full heating season covered by the utility's initial GPIM, the utility shall file an application for the renewal of the GPIM. Implementation of the initial GPIM shall continue until the renewed GPIM goes into effect. For the utilities with an initial GPIM based on the framework set forth in paragraph 4607(a), the renewal application shall present an analysis of the implementation of the utility's initial GPIM as approved by the Commission and an analysis of GPIM benchmark gas rate and GPIM sharing amount in paragraph 4607(b) as if they had instead been implemented over the same period as the initial GPIM. The utility may propose to implement a modified GPIM provided that the Commission determines the modified GPIM comports with the requirements of § 40-3-120, C.R.S.

4603. Gas Cost Adjustments.

(a) Scheduled filings. A utility shall submit a GCA filing to adjust its GCA. The GCA filing shall be filed pursuant to the schedule provided in rule 4602. The GCA filing shall be submitted not less than two weeks in advance of the proposed effective date.

(b) Additional filings. If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may submit a GCA filing to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent ($0.01) per Mcf or Dth.

(c) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.

(d) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.

(e) Financial gas commodity hedging. Costs related to gas price volatility risk management through financial hedging for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4608.

(f) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

GCA = (current gas cost + deferred gas cost) - (base gas cost).

(g) Gas price risk management plan. The calculation of the GCA shall be subject to a maximum cap based on a set percentage of an average of the utility's historical GCAs and to a minimum threshold based on a set percentage of an average of the utility's historical GCAs in accordance with the utility's gas price risk management plan as approved by the Commission. Prudently incurred costs above the maximum cap shall be recorded in a deferred balance that is recoverable and amortized over an appropriate timeline of no more than five years with financing costs, as determined by the Commission. Collections at the minimum threshold shall be recorded in a reserve fund, not to exceed an amount established by the Commission, and shall be used to offset any deferred balance of prudently incurred costs above the maximum cap.

4604. Contents of GCA Filings.

(a) A GCA filing shall meet the following requirements.

(I) Every GCA filing shall contain attachments 1 through 9. The attachments shall meet the requirements set out in this rule.

(II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.

(III) Attachments 2, 3, 5, and 6 shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(IV) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application. Work-papers shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(V) The filing shall cross-reference the proceeding numbers of the associated GPP submittals.

(VI) An explanation of all pro forma adjustments shall be provided, if applicable.

(b) GCA attachment No. 1 - GCA summary. This attachment shall clearly illustrate all of the following principles.

(I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis.

(II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil ($0.001, minimum) per Mcf or Dth basis; and

(III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.

(c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity. The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP, as required pursuant to rule 4606.

(I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil ($0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

(II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.

(d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs, the calculation of deferred gas cost, the implementation of the utility's GPRMP, and the calculation of the GPIM symmetric sharing amounts, as approved by the Commission. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, GPIM sharing amounts, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity for the next 12-month period. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its GCA filings, the utility shall reflect actual deferred costs for the most recent period, or as otherwise approved by the Commission.

(e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently effective rates for sales gas service and, where applicable, gas transportation service.

(f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:

(I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and

(II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.

(g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:

(I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and

(II) derive the amount of the GCA applied to each specific sales gas customer class, subject to the utility's GPRMP and GPIM, and, where applicable, gas transportation customer rate classes.

(h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:

(I) current and proposed GCA rates and percentage change;

(II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;

(III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and

(IV) a statement that the utility made a separate gas purchase report filing in accordance with rule 4608 to begin the initial prudence review evaluation process for the prior gas purchase year.

(i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.

(j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.

(k) GCA attachment No. 10 - GPIM sharing amounts. As applicable, this attachment shall detail the calculation of GPIM sharing amounts per rule 4607 and any sharing amounts included in the deferred gas cost calculation presented in attachment No. 3. The calculation of the sharing amounts shall be provided in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

4605. Gas Purchase Plans.

(a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

(b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:

(I) the information required by rule 4606;

(II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;

(III) the utility's forecasted pricing for each receipt point/area; and

(IV) the utility's portfolio management plan.

(c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.

(d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.

(e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.

(f) Modified GPP. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

4606. Contents of the GPP.

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

(b) GPP attachment No. 2 - gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.

(c) GPP attachment No. 3 - portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.

(d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:

(I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand.

(II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.

(III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.

(IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

4607. Gas Performance Incentive Mechanism.

In conjunction with its GPRMP, the utility shall implement a GPIM in accordance with this rule and the specific terms set forth in its GCA tariff sheets. The utility shall implement a GPIM for each GCA rate area with more than 50,000 full service customers or each purchasing region as specified in the utility's GPP.

(a) An application to establish a GPIM for a utility with more than 50,000 but less than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (I) through (IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(I) GPIM benchmark. Methodology to establish the GPIM benchmark for commodity gas purchases based on verifiable, reported market indices, with a reasonable adjustment, and for appropriate locations.

(II) GPIM commodity gas volumes. Description and explanation of all gas volumes to be included in the GPIM.

(A) The volumes and costs associated with fixed-price, long-term supply contracts may be excluded from the GPIM and risk sharing calculation.

(B) The volumes and costs associated with storage injections and withdrawals, including both physical and contract storage, may be excluded from the GPIM and risk sharing calculation. Utilities shall provide a description of storage assets to be either included or excluded from the GPIM.

(C) The volumes and costs associated with associated with financial hedging shall be excluded from the GPIM and risk sharing calculation.

(D) All other actual gas volumes and costs shall be subject to the GPIM with consideration of reasonable adjustments as determined by the Commission.

(III) Upstream supply costs. Description and explanation of upstream costs included in the GPIM risk sharing mechanism, including the methodology for developing an appropriate benchmark for such costs, if appropriate.

(IV) Risk sharing amount. Methodology for calculating the risk sharing amount.

(A) A formula will calculate a percentage of the difference between the actual gas costs and the benchmark formula for applicable gas volumes, either positive or negative, borne or retained by the utility, subject to applicable limitations.

(B) The utility shall explain:

(i) any proposed deadband around the GPIM benchmark whereby price variation within the deadband is excluded from risk sharing formula;

(ii) any proposed cap or floor on the results of the risk sharing; and

(iii) any proposed methodology for applying force majeure or similar provisions to the risk sharing mechanism.

(C) Backcasting analysis, based on a minimum of the most recent three years of historical data, will demonstrate how the proposed GPIM benchmark would have been calculated and how the proposed risk sharing mechanism would have performed over the historical period. This analysis shall assume the utility made no changes to its actions in response to the mechanism and ignore any force majeure or similar events. The utility may, in its discretion, present additional analysis.

(b) An application to establish a GPIM for a utility with more than 500,000 full service customers shall contain the following elements. The utility shall specifically reference and respond to the requirements of subparagraphs (I) through (IV) of this rule and shall provide cross-references and footnoted work-papers in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by Commission staff.

(I) GPIM benchmark gas rate. The GPIM benchmark gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the average of the GPIM total gas cost for that same quarter in the previous three years divided by the GPIM total gas quantity for the same quarters in the previous three years.

(II) GPIM actual gas rate. The GPIM actual gas rate for the completed calendar quarter preceding the GCA filing will be calculated as the GPIM total gas cost for that quarter divided by the GPIM total gas quantity for that same quarter.

(III) GPIM sharing amount. The GPIM sharing amount will be calculated as four percent of the difference between the GPIM benchmark gas rate and the GPIM actual gas rate, either positive or negative, multiplied by the GPIM total gas quantity for the completed calendar quarter preceding the GCA filing, subject to the following limitations:

(A) the GPIM sharing amount for a quarter shall be zero if the difference between the GPIM benchmark gas rate and the GPIM actual gas rate is less than $0.50 per Mcf or Dth;

(B) the GPIM sharing amount for a quarter shall be the difference between the GPIM benchmark gas rate and the GPIM actual gas rate that is above or below the $0.50 per Mcf or Dth threshold in subparagraph 4607(b)(III)(A); and

(C) the utility's cumulative quarterly GPIM sharing amounts summed across all GCA rate areas or purchasing regions, positive or negative, shall be capped over a rolling twelve-month period at an amount equal to a 30 basis point return on the utility's rate base as established by the Commission in the utility's most recent base rate proceeding, set solely on the equity share of the utility's capital structure.

(IV) The utility may request, and the Commission may grant, a force majeure exception upon good cause shown after such an event has occurred. The force majeure exception may allow the utility to exclude costs from the GPIM that are deemed to be either associated with the force majeure event as defined by the utility's tariffs on file with the Commission or associated with force majeure events as defined in the utility's upstream gas supply, storage, and transportation agreements and tariffs.

(c) Unless subject to the limitations in subparagraph 4607(a)(IV)(B)(ii) or subparagraph 4607(b)(III)(C), the GPIM sharing amount shall be accounted for in the utility's deferred gas cost calculation for the quarterly GCA filing.

(I) To the extent a GCA calculation is subject to a maximum cap specified in a utility's GPRMP, any new positive GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be subject to a carryforward into subsequent GCA quarterly filings. The carried forward GPIM amount shall be eligible to offset incurred negative GPIM sharing amounts.

(II) To the extent a GCA calculation is subject to a minimum threshold specified in a utility's GPRMP, any new negative GPIM sharing amount will not be accounted for in the deferred gas cost calculation but instead be accounted for in the deferred gas cost calculation in subsequent quarterly GCA filings in which the GCA calculation is above the minimum threshold.

4608. Gas Purchase and Deferred Balance Reports and Prudence Reviews.

(a) GPDBR filing requirements. The utility shall file a GPDBR in accordance with paragraph 4602(e) for the review and approval of the calculation of the deferred GCA balance including the implementation of the utility's GPIM, as applicable, for the previous four quarters ending June 30. The GPDBR shall be filed under the previous year's GPP proceeding number (filed approximately 15 months previously). Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPDBR filing.

(b) Prudence review process. Based on the initial evaluation of the GPDBR, including the results of the GPIM, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GDBPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

(c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action). The Commission may consider, as appropriate, whether the utility employed carefulness, precaution, attentiveness, and good judgment.

(d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

(e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

4609. Contents of the GPDBR.

A GPDBR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA filing pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work-papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

(a) GPDBR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year. Each gas utility shall provide a description and explanation of the following:

(I) the volumes and costs associated with fixed-price, long-term supply contracts;

(II) the volumes and costs associated with storage injections and withdrawals, including both physical and contract storage; and

(III) the volumes and costs associated with financial hedging.

(b) GPDBR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.

(c) GPDBR attachment No. 3 - actual portfolio purchases. This attachment shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4608(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.

(d) GPDBR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

(I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;

(II) an itemized listing of the specific costs the utility incurred to purchase upstream services;

(III) actual peak day demand experienced by the utility during the gas purchase year; and

(IV) an itemized list of capacity release volumes and revenues.

(e) GPDBR attachment No. 5 - deferred balances. This attachment shall provide monthly deferred balances for the 12 months ending June 30.

(f) GPDBR attachment No. 6 - GPIM results. This attachment shall provide, for the 12 months ending June 30:

(I) the quarterly GPIM benchmark gas rates and GPIM actual gas rates;

(II) the quarterly and twelve-month cumulative GPIM sharing amounts; and

(III) the calculation of the applicable cap on GPIM sharing amounts.

4610. Confidentiality.

(a) For each attachment filed by the utility as confidential under rules 4600 through 4610, the utility shall provide, at a minimum, a version of the attachment with publicly available information.

(b) The Office of the Utility Consumer Advocate (UCA) may provide each utility annually, on or before January 1 of each year, an executed generic nondisclosure agreement with the utility so that the utility shall provide such confidential information to the UCA when any utility filings are made pursuant to rules 4600 through 4609 for the subsequent year.

4611. – 4699. [Reserved].