Decision No. C24-0778

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24AL-0049G

IN THE MATTER OF ADVICE LETTER NO. 1029 - GAS FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 6 - GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES, TO BECOME EFFECTIVE FEBRUARY 29, 2024.

COMMISSION DECISION PERMANENTLY SUSPENDING TARIFF SHEETS, ESTABLISHING NEW BASE RATES, REQUIRING COMPLIANCE TARIFF FILING, AND REQUIRING FUTURE ADVICE LETTER FILING

Issued Date: October 25, 2024
Adopted Date: October 9 and 16, 2024

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I. BY THE COMMISSION

A. Statement

1. On January 29, 2024, Public Service Company of Colorado ("Public Service" or the "Company") filed Advice Letter No. 1029-Gas with revised tariff sheets to increase its base rate revenue collections for all natural gas sales and transportation services and to make certain other changes to the Company's Colorado P.U.C. No. 6-Gas Tariff.

2. By this Decision, the Commission permanently suspends the effective date of the tariff sheets filed with Advice Letter No. 1029-Gas and orders Public Service to file compliance tariffs with new base rates for retail gas service consistent with the findings and conclusions in this Decision. We also direct Public Service to file a future advice letter tariff filing to further modify the base rate tariff sheets and other elements of its P.U.C. No. 6-Gas Tariff. Specifically, we require Public Service to submit for Commission review the Company's full line extension policy and its approach to recovering the costs associated with system growth and capacity expansion investments, consistent with the discussion below.

B. Background

1. Advice Letter No. 1029-Gas

3. Public Service initiated a "Phase I" rate proceeding by filing Advice Letter No. 1029-Gas. The Company supports a target for an overall increase in base rate revenue of approximately $171 million primarily by presenting a cost of service study ("COSS") and by justifying the principal components of its base rate revenue calculation and the related changes to the tariff sheets through the Direct Testimony of 17 witnesses.

4. Public Service states the majority of its request to increase base rate revenue collections is driven by plant investments since the Company's previous rate case in Proceeding No. 22AL-0046G ("2022 Gas Rate Case"). Public Service states other drivers for the increase in base rates include investments in information technology and increases in operations and maintenance ("O&M") expenses due to inflation, new labor agreements, and other market factors. The higher level of base rate revenues sought by Public Service is also premised on an authorized return on equity ("ROE") of 10.25 percent, a cost of long-term debt of 4.05 percent, a short-term cost of debt of 5.81 percent, and a capital structure of 55.0 percent equity, 43.18 percent long-term

debt, and 1.82 percent short-term debt, which results in an overall weighted average cost of capital ("WACC") of 7.50 percent.

5. Public Service proposes to cause the increase in its base rate revenues by implementing a General Rate Schedule Adjustment ("GRSA") as set forth on Sheet No. 48 filed with Advice Letter No. 1029-Gas. The Company proposes that the GRSA be applied as a surcharge to the components of its existing base rates in its P.U.C. No. 6-Gas Tariff, exclusive of Service and Facility charges.

6. At the time of the filing of Advice Letter No. 1029-Gas, the estimated bill impact of the $171 million increase was about 9.5 percent for residential customers and 8.5 percent for small commercial customers. Such potential bill impacts potentially resulting from this rate proceeding prompted an extraordinary number of written public comments objecting to the Company's request to raise rates.

7. In order to mitigate the projected increase in customer bills, Public Service proposes deferring the implementation of increased base rates until February 15, 2025, when the rider recovery for costs associated with the 2021 Winter Storm Uri terminates pursuant to the decision rendered in Proceeding No. 21A-0192EG ("Winter Storm Uri Proceeding"). The Company would track the deferred revenue from November 2024 through February 2025, then apply a proposed Revenue Deferral Surcharge on customer bills for the period of February 15, 2025, through February 15, 2026, to recover the deferred revenue. The Company proposes that the balance to be collected by the Revenue Deferral Surcharge would include a return set at the Company's WACC.

8. Public Service also seeks authority to implement a decoupling mechanism called the Revenue Stability Mechanism, which it states would be intended to support the Company's financial health while removing any barriers to the gas utility promoting electrification or

conservation. Public Service requests extension of the Company's gas quality of service plan tariff through 2026. The Company requests approval of an updated schedule of charges for rendering service and of updates to standardized costs for gas line extensions. Public Service further requests approval of changes to its Gas Storage Inventory Cost ("GSIC") to allow for a return at the Company's WACC.

2. Procedural History

9. By Decision No. C24-0129, issued February 28, 2024, the Commission certified the base rate tariff filing as complete for purposes of § 40 3-102.5(1)(b), C.R.S., and Rule 4109(f) of the Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* ("CCR") 723-4. The Commission set the tariff sheets filed with Advice Letter No. 1029-Gas for hearing and suspended their effective date to June 28, 2024, pursuant to § 40-6-111(1), C.R.S. By the same Decision, the Commission established a 30-day notice and intervention period, ending on March 29, 2024.

10. By Decision No. C24-0235-I, issued April 16, 2024, the Commission further suspended the tariff sheets filed with Advice Letter No. 1029-Gas for an additional 130 days, to November 5, 2024, pursuant § 40-6-111(1), C.R.S. The Commission acknowledged the notices of intervention of right filed by Trial Staff of the Commission ("Staff") and the Colorado Office of the Utility Consumer Advocate ("UCA") and granted the requests for permissive intervention filed by Atmos Energy Corporation; Colorado Natural Gas; Climax Molybdenum Company; City of Pueblo; Tiger Natural Gas, Inc.; and WoodRiver Energy, LLC.

11. By Decision No. C24-0240-I, issued April 17, 2024, the Commission directed Public Service to file Supplemental Direct Testimony addressing issues relating to credit metric

scenarios, capital additions, net salvage value, 15-year rate forecast, customer disconnection information, affordability metrics, and system capacity considerations.

12. By Decision No. C24-0281-I, issued April 29, 2024, the Commission established the procedural schedule for this Proceeding including scheduling the remote evidentiary hearing.

13. By Decision No. C24-0342-I, issued May 21, 2024, the Commission scheduled a remote public comment hearing for July 25, 2024.

14. On May 30, 2024, Public Service filed Supplemental Direct Testimony in response to Decision No. C24-0240-I.

15. On July 11, 2024, the City of Pueblo, Staff, and UCA each filed Answer Testimony.

16. On July 25, 2024, the Commission held an *en banc* remote public comment hearing via Zoom in order to receive oral comment from the public. The oral comments generally expressed concern that utility bills continue to increase and requested that the Commission decline to grant additional rate increases.

17. On August 15, 2024, Public Service filed Rebuttal Testimony.

18. The evidentiary hearing was held before the Commission *en banc* on September 4, 5, 6, 10, 11, and 12, 2024. At the start of the evidentiary hearing, the Commission admitted all pre-filed testimony and attachments into the evidentiary record. During the course of the hearing, the Commission admitted additional hearing exhibits that were offered by parties during their cross-examination or re-direct of witnesses.

19. On September 26, 2024, the City of Pueblo filed its post-hearing Statement of Position ("SOP"). On September 27, 2024, Public Service, Staff, and UCA filed their respective SOPs.

20. In addition to the public comments provided orally at the public comment hearing, the administrative record for this Proceeding includes more than 880 written public comments generally opposing any rate increase. Commenters express that they cannot afford higher utility bills and are already struggling to make ends meet, with many mentioning low or fixed incomes, with some depending solely on Social Security benefits.

21. The Commission deliberated at its October 9 and 16, 2024 Commissioners' Weekly Meetings, resulting in this Decision.

C. Discussion, Findings, and Conclusions

1. Legal Standards and Ratemaking Process

a. Burden of Proof and Record

22. As the party seeking Commission approval or authorization, Public Service bears the burden of proof with respect to the relief sought;[1] intervenors bear the burden of proof with regard to each of their proposals advanced in Answer Testimony. The burden of proof is by a preponderance of the evidence.[2] A party has satisfied its burden under this standard when the evidence, on the whole, tips in favor of that party. The evidence must be "substantial evidence," which is defined as "such relevant evidence as a reasonable person's mind might accept as adequate to support a conclusion … it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury."[3] In rate cases, after the utility proposing a tariff change presents its case-in-chief, putting forth

[1] *See* Rule 1500, 4 CCR 723-1 (burden of proof and initial burden of going forward shall be on the party that is the proponent of a decision, *i.e.*, the regulated entity proposing a tariff change) and § 24-4-105(7), C.R.S. (proponent of order has burden of proof).

[2] *See* § 13-25-127(1), C.R.S. (burden of proof in any civil action shall be by a preponderance of the evidence).

[3] *City of Boulder v. Pub. Utils. Comm'n*, 996 P.2d 1270, 1278 (Colo. 2000) (quoting *CF&I Steel, L.P. v. Pub. Utils. Comm'n*, 949 P.2d 577, 585 (Colo. 1997)).

evidence to justify its requested rate increase, the burden of going forward shifts to intervenors who then have the opportunity to provide evidence either rebutting the proponent's evidence or supporting intervenors' own arguments. The Commission has an independent duty to determine matters that are within the public interest.[4]

b. Duty and Authority to Set Rates

23. The setting of just and reasonable rates, both as to level and design, goes to the very essence of the Commission's powers and duties.[5] The Commission is an administrative agency of the legislature,[6] charged with the authority, and duty, to regulate the rates of public utilities operating within Colorado. Section 40-3-102, C.R.S., vests in the Commission the power to regulate all the rates, charges, and tariffs of every public utility in this state and to do all things necessary or convenient in the exercise of such power. Article XXV of the Colorado Constitution affirms the General Assembly's power to regulate public utility facilities, service, and rates and charges, and delegates that power in all respects to the Commission. These principles of Colorado constitutional law are known as the "*Miller Brothers* Doctrine" pursuant to the holding in *Miller Brothers, Inc. v. Public Utilities Commission*,[7] that the Commission has as much authority as the General Assembly possessed prior to the adoption of Article XXV in 1954, unless and until the General Assembly enacts a specific statutory restriction on the Commission's authority, which then controls.

[4] *Caldwell v. Pub. Utils. Comm'n,* 692 P.2d 1085, 1089 (Colo. 1984).

[5] *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n*, 760 P.2d 627, 638 (Colo. 1988); *see* §§ 40-3-101, 40-3-102, 40-3-111, and 40-6-111, C.R.S. (Commission is charged with ensuring that utilities provide safe and reliable service to customers at just and reasonable rates).

[6] By the Public Utilities Act of 1913, codified at § 40-3-102, C.R.S., the legislature created the Commission and vested it with jurisdiction over the regulation and control of public utilities. *See People v. Colorado Title & Tr. Co.*, 178 P. 6, 10 (Colo. 1918).

[7] *Miller Bros., Inc. v. Pub. Utils. Comm'n*, 525 P.2d 443, 451 (Colo. 1974).

24. Pursuant to these statutory and constitutional authorities, the Commission has a general responsibility to protect the public interest regarding utility rates and practices and has broadly based power to do whatever it deems necessary or convenient to accomplish this function.[8] In fulfilling this duty, the Commission conducts hearings to investigate the propriety of a public utility's proposed rate changes and to determine the just and reasonable rates to be charged.[9] Section 40-3-111, C.R.S., expressly authorizes the Commission to determine the just and reasonable rates to be charged to customers by public utilities.

c. Just and Reasonable Standard

25. As codified in state law, § 40-3-101(1), C.R.S., the rates and charges assessed for public utility service must be "just and reasonable." The Colorado Supreme Court has held the primary purpose of utility regulation is to ensure the rates charged are not excessive or unjustly discriminatory.[10] Further, § 40-3-101(2), C.R.S., requires a utility to provide such service and facilities as shall promote the safety, health, comfort, and convenience of its patrons, employees, and the public, and as shall in all respects be adequate, efficient, just, and reasonable.

26. Under the just and reasonable standard, the Commission considers both the utility investors' interest in avoiding confiscation and the utility customers' interest in preventing exorbitant rates.[11] This requires the Commission to protect the public interest by ensuring rates are not excessive, burdensome, or unjustly discriminatory while protecting the right of the utility and its investors to earn a return reasonably sufficient to attract capital and maintain the utility's

[8] *City of Montrose v. Pub. Utils. Comm'n*, 629 P.2d 619, 623 (Colo. 1981).

[9] § 40-3-111, C.R.S.; *see CF&I Steel*, 949 P.2d at 584 (finding the Commission has a duty to examine proposed rates and to determine whether they are unjust, unreasonable, discriminatory, or preferential, or in any way violate any provision of law, and if so, to set just and reasonable rates).

[10] *Cottrell v. City & County of Denver*, 636 P.2d 703, 711 (Colo. 1981).

[11] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Colo. Mun. League v. Pub. Utils. Comm'n*, 687 P.2d 416, 418 (Colo. 1984).

financial integrity. So far as the utility is concerned, it must have adequate revenues for operating expenses and to cover the capital costs of doing business, and its revenues must be sufficient to assure confidence in its financial integrity so as to maintain credit and to attract capital. Consequently, "just and reasonable" rates set by the Commission protect both the right of consumers to pay a rate which accurately reflects the cost of service rendered and the right of the utility and its investors to earn a return reasonably sufficient to maintain its financial integrity.[12] The ratemaking function involves the making of pragmatic adjustments and there is no single correct rate.

d. Holistic Ratemaking Process

27. As the Colorado Supreme Court has long recognized, "rate making is not an exact science," and when it sets rates, the Commission necessarily exercises judgment rather than complete reliance on a mathematical or legal formula, to establish just and reasonable rates that balance the interests of both the utility investors and customers.[13]

28. While the Commission's decision must be based upon evidentiary facts, calculations, and known factors, it necessarily exercises much judgment in the findings and conclusions it makes based on the evidence when setting the final level of rates.[14] For example, as the Colorado Supreme Court has expressly identified, in setting an appropriate utility rate the Commission considers cost of service along with other factors which are rationally related to

[12] *Pub. Serv. Co. v. Pub. Utils. Comm'n*, 644 P.2d 933, 939 (Colo. 1982).

[13] *Pub. Utils. Comm'n v. Nw. Water Corp.*, 451 P.2d 266, 276 (Colo. 1963).

[14] *See Mountain States Tel. & Tel. Co. v. Pub. Utils. Comm'n*, 513 P.2d 721, 726 (Colo. 1973) (Commission must have before it evidence, but determining what is a just and reasonable rate is a matter of judgment or discretion).

legitimate utility regulatory purposes.[15] As the Court reasoned, without such discretion, the Commission would "become a rubber stamp relegated to examining cost studies of utilities."[16]

29. In executing its duty to adopt rates that are fair and reasonable, the Commission is not limited to options formally presented by the parties.[17] So long as the findings of fact on which the rate is founded have a legally adequate basis in the evidence and pass the constitutional tests, the courts will not disturb the Commission's determination. In this inquiry, it is the result reached, not the particular rate methodology employed by the Commission, that determines whether a rate is just and reasonable.[18]

30. The Colorado Supreme Court has described the Commission's rate setting as "a stream bounded on each side by the limits of discretion" and instructed reviewing courts to determine whether the Commission's end result stayed within its discretionary channels.[19] A rate that is neither so unreasonably low as to deprive the utility of its constitutional right of compensation nor too excessive so as to unjustly exploit of customers should not be subject to revision. As the U.S. Supreme Court said in *Hope* years ago, "It is … the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry … is at an end."[20]

31. We reiterate these principles here to elucidate that our decision-making in this rate case inherently involves myriad interrelated legal conclusions, factual findings, and policy

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[15] *CF&I Steel*, 949 P.2d at 588.

[16] *Id*. (quoting *Integrated Network Servs., Inc. v. Pub. Utils. Comm'n*, 875 P.2d 1373, 1383 (Colo. 1994)).

[17] *Integrated Network Servs.*, 875 P.2d at 1381.

[18] *Glustrom v. Pub. Utils. Comm'n*, 280 P.3d 662, 669 (Colo. 2012); *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n,* 602 P.2d 861, 864 (Colo. 1979) (citing *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)).

[19] *Colo. Mun. League v. Pub. Utils. Comm'n*, 473 P.2d 960, 971 (Colo. 1970).

[20] *Hope*, 320 U.S. at 602.

decisions—all of which contribute to our final determination of what constitutes just and reasonable rates. In addition to the consideration of mathematical figures and equations that the parties present to support targets for revenue collections from rates, we must evaluate the effect of many factors, exercising broad legislative discretion as well as regulatory expertise. To disturb one factor considered by the Commission in setting the final rates risks upsetting the careful balance achieved by the Commission. While the adjudicative process requires that we resolve specific contested issues raised by the parties, we approach each interrelated decision cognizant that, as the revenue requirement increases, so do rates, and thus each decision requires balancing of a fair return for the company with reasonable rates for customers. Given the interrelated nature of rate case decision-making, as long as the outcome results in *overall* just and reasonable rates, any attempt to reexamine, after-the-fact, a single building block of that end result seems inappropriate. The intricate nature of our task is precisely why the legality of the end result of ratemaking, and not the legality of each calculation or input, controls.[21] An isolated increase (or decrease) in rates based solely on one factor could unbalance and distort the ratemaking structure. Consequently, reversal of a single issue may not necessarily lead to a change in rates as the Commission could very well determine that inclusion of the erroneous component did not cause the overall rates to be unjust or unreasonable. Or the Commission could determine that, in order to consider an adjustment, it must undertake a more comprehensive review re-examining other potentially affected elements of the revenue requirement target. The outcome would naturally depend on the specific characteristics of the issue and the reach of the reviewing court's ruling.

[21] *Glustrom*, 280 P.3d at 669.

2. Establishment of New Base Rates

a. Introduction

32. Public Service's request to increase base rate revenue collections is largely driven by the pace of plant investments made by the Company since the 2022 Gas Rate Case. Of the overall $171 million revenue deficiency presented in the Company's Direct Testimony, approximately $102 million relates to increased capital investment.

33. In its post-hearing SOP, Public Service acknowledges that state legislation and Commission decisions have dramatically changed public policy around the provision of gas utility service in just the past few years. The Company states that the resulting key directives of the changes in policies will first meaningfully impact investments after this rate case. The Company further argues that the nature of its obligation to serve customers will be the subject of future proceedings. Now, when new base rates take effect as a result of this Proceeding, the Company will continue to be obligated to provide gas service to existing and requesting customers at the same time it actively supports efforts to significantly reduce greenhouse gas emissions. The Company states this rate case is about cost recovery of past investments and the costs necessary to provide safe and reliable service to customers today.

34. In contrast, Staff argues in its post-hearing SOP that, while Public Service cloaks its proposals under the guise of keeping the Company at the forefront of the energy transition in Colorado, the proposals the Company puts forward in this rate case are aimed primarily at rewarding shareholders. Staff argues the requested rate increase is unreasonably high and instead recommends that the Commission approve a lower overall increase than proposed by Public Service.[22]

[22] Staff SOP at pp. 1–2.

35. UCA likewise in its SOP puts this rate case in the following context: Public Service is requesting a 21.5 percent increase in base rate revenue collections from customers and an increase of 11.7 percent in total revenue.[23] If Public Service's proposals in this case are approved, the Company's gas revenues will have doubled to nearly $2 billion in only the last four to five years.[24] UCA concludes that "business as usual" investments will create major economic friction without additional throughput, but additional throughput runs counter to Colorado energy policy.[25]

b. 2023 Calendar Year Test Year

36. Through the testimony filed initially with Advice Letter No. 1029-Gas, Public Service proposed to base the target revenue requirement for setting new base rates on a test year with known plant balances through September 2023 and forecasted balances from October through December 2023.

37. Staff and UCA contested the proposed test year through their respective Answer Testimony, arguing that the target should be based on a full 2023 calendar year test year without the forecasted balances.

38. Through Rebuttal Testimony, Public Service accepted Staff and UCA's proposal for using the 2023 calendar year as the test year in this Proceeding.

39. The selection of a test year comes to us not as a contested matter, and we authorize the use of the calendar year 2023 test year as proposed by Public Service in its Rebuttal Testimony as the basis for establishing the revenue requirement for new base rates in this Proceeding.

[23] UCA SOP at p. 4.
[24] UCA SOP at p. 5.
[25] UCA SOP at pp. 5–6.

40. However, as discussed below, there are several contested matters that comprise the components of the otherwise uncontroversial test year selection. For instance, Public Service seeks to base revenue requirements on a year-end rate base valuation, whereas Staff and UCA favor using a 13-month average convention. Staff and UCA also contest the inclusion of certain investments in the Company's rate base, such as the Questar Supply Project, the Clarkson Street Project, and the Private Long-Term Evolution ("LTE") Project, a wireless network intended to serve as a backup system to reduce outages and dispatch field workers. Staff and UCA likewise object to various levels of expenses used by the Company to justify its proposed base rate revenue target.

c. Rate Base

(1) Value of Rate Base

41. Public Service maintains that year-end rate base valuation is appropriate because that level of investment costs is representative of the investment costs that will be incurred when the rates resulting from this Proceeding will be in effect (*i.e.*, starting in either November 2024 or February 2025 if the implementation deferral and the proposed Revenue Deferral Surcharge are adopted). The Company cites the 2022 Gas Rate Case as an example of the Commission's understanding of an appropriate way to address regulatory lag.

42. Public Service argues that the Company's adoption of an average rate base valuation in this Proceeding will negatively impact its financial health and will also cause the filing of more frequent rate cases while the Company also develops Clean Heat Plan programs and transitions to new, more restrictive gas infrastructure planning requirements. The Company notes that 50 percent of the investments that have built the growing rate base in this case are safety and integrity related, and that, with the Pipeline Safety and Integrity Adjustment ("PSIA")—a

temporary rate adjustment mechanism previously implemented to address pipeline replacements and other safety-related expenditures—no longer available, a 13-month average rate base imposes a regulatory lag that does not reflect the period in which the investments were made.[26] That is, Public Service contends the new investment reviewed as part of the test year rate base in this Proceeding reflects the recent termination of the PSIA rider, which when implemented had mitigated regulatory lag.[27]

43. Public Service also argues that while a 13-month average rate base results in an actual 16-month lag in capital cost recovery, a year-end rate base still results in a six-months lag, thus narrowing but not eliminating the gap between when the investments were made and when costs are recovered. Public Service further argues that a year-end rate base is consistent with reductions in regulatory lag in cost recovery for the Company's electric utility operations.[28]

44. Staff rejects the Company's request for year-end methodology and recommends the Commission instead adopt the 13-month average convention for valuing the rate base for the test year. Staff contends that using a 13-month average will decrease the Company's revenue requirement by $21.6 million, a valuation that it contends is more reasonable and better addresses affordability concerns. Staff argues that averaging rate base values better reflects the "lumpiness" of investments. Staff further notes that there are no extraordinary circumstances, such as earnings attrition, to warrant the year-end valuation.[29]

45. Staff further rejects Public Service's arguments that its financial health is of concern, noting that Xcel Energy, the Company's parent holding company, realized earnings of

[26] Hr. Ex. 136, Freitas Rebuttal, pp. 40:13–41:3.
[27] Hr. Ex. 124, Berman Rebuttal, pp. 10:12–11:15.
[28] Public Service SOP at p. 7.
[29] Hr. Ex. 400, Ghebregziabher Answer, pp. 48:19–49:13.

some $1.85 billion in 2023, up from $1.74 billion in 2022.[30] Staff also contends that the Commission should disregard the Company's argument that termination of the PSIA is reason to allow a year-end rate base methodology, because the PSIA was an extraordinary cost recovery mechanism that was intended to be temporary. According to Staff, the Company should have understood the intent of the PSIA was to accelerate safety measures but that it was not to be used as a default mode for cost recovery.

46. UCA likewise maintains that the use of a 13-month average rate base is appropriate because: it is consistent with the regulatory matching principle; the Commission has a history of favoring the use of the average rate base; there has been no showing of extraordinary circumstances or earnings attrition; and there are advantages to imposing regulatory lag that are in the public interest.[31]

47. Specifically, UCA argues that the matching principle is important in ratemaking to ensure that a balanced relationship between investments, revenues, and expenses is maintained. Additionally, average rate base reflects plant being put in and taken out of service throughout the year, not just at a specific point in time. UCA contends that looking at a singular point in the year, as the year-end convention does, creates an incentive for the utility to augment plant at that time to its advantage, but not necessarily in ratepayers' interest.

48. UCA further contends that the year-end methodology authorized in the 2022 Gas Rate Case should not be considered as precedent, because that authorization by the Commission was specific to the evidentiary record of that earlier proceeding and does not apply here. Citing Decision No. C22-0804, UCA notes that the year-end methodology authorization was based on

[30] Hr. Ex. 400, Ghebregziabher Answer, p. 60:5-13.
[31] Hr. Ex. 500, Skluzak Answer, p. 63:5-9.

"the inter-relatedness of the various financial components at issue, including the appropriate valuation of the test year rate base."[32] UCA also points to the outcome of the Company's 2017 Phase I gas rate case,[33] where, UCA argues that, upon judicial review, a Denver district court judge ruled against Public Service on appeal of the Commission's authorization of a 13-month average rate base, determining that the Company had not shown significant earnings attrition. UCA contends the issues in the 2017 case are similar to what the Company put forward here.[34]

49. In response to Staff and UCA, Public Service warns against placing weight on a goal of achieving lower rates as a reason to adopt the 13-month average convention for valuing the test year rate base. The Company further argues that regulatory lag is not a reasonable incentive for the Company to control costs because the Company must make investments to continue to serve its customers.[35] Because there will be regulatory lag due to the Company's willingness to put forward for consideration a historical test year instead of a future test year, Public Service contends the additional lag that comes with the adoption of average rate base is not necessary in this case.[36]

50. The Company further refutes arguments that average rate base provides a more representative level of rate base or that the Company is incented to place plant into service at the end of the test year, generally stating rate base is not calculated on plant additions but rather on plant balances, which are cumulative.[37] The Company also takes issue with the argument that

[32] Hr. Ex. 500, Skluzak Answer, p. 68:1-6.
[33] Proceeding No. 17AL-0363G.
[34] Hr. Ex. 500, Skluzak Answer, p. 76:1-11.
[35] Hr. Ex. 136, Freitas Rebuttal, pp. 21:16–22:21.
[36] Hr. Ex. 136, Freitas Rebuttal, p. 24:8-10 and p. 25 figs. APF-R-1 and APF-R-2.
[37] Hr. Ex. 136, Freitas Rebuttal, pp. 26:14–28:8.

average rate base adheres to the regulatory matching principle, asserting that its preferred year-end methodology reflects the costs expected to be incurred in 2024 as costs continue to rise.[38]

51. Furthermore, Public Service argues that the Commission has never determined a threshold for under-earnings[39] and contends that inflation-induced increases in O&M costs and continued required investment in nonrevenue-producing assets undermine the Company's ability to earn its authorized return.[40] Hence, Public Service contends the evidence used to show that it is not suffering earnings attrition in fact illustrates the existence of earnings attrition.[41] As to the arguments that the Company has not earned its authorized return even when a year-end rate base has been authorized, the Company contends the issue must be viewed in a "holistic manner" with consideration of other factors including disallowance of expenses, rate case timing, and rate riders.[42] Public Service concludes that regulatory lag, exacerbated by the growth in capital expenditures as presented in this Proceeding, will continue to diminish the Company's opportunity to earn its authorized return.[43]

52. We find a 13-month average rate base valuation is appropriate in this Proceeding for the many reasons set forth by Staff and UCA in their advocacy in this case. Except for the specific findings in the 2022 Gas Rate Case, the Commission has consistently authorized a 13-month average methodology. We are further unpersuaded to adopt the year-end convention in this Proceeding. We find Public Service has not provided sufficient evidence to support its contention that a year-end methodology is necessary to advance the public interest.

[38] Hr. Ex. 136, Freitas Rebuttal, p. 47:1-22.
[39] Hr. Ex. 136, Freitas Rebuttal, p. 37:15-17.
[40] Hr. Ex. 136, Freitas Rebuttal, pp. 38:1–40:22.
[41] Hr. Ex. 117, Freitas Direct, p. 40 tbl. APF-D-3.
[42] Hr. Ex. 136, Freitas Rebuttal, pp. 42:3–43:5.
[43] Hr. Ex. 117, Freitas Direct, p. 40:3-13.

53. Although we do not modify the components of the rate base used by Public Service in its COSS to establish a base rate revenue target, as explained in more detail below, we are nonetheless disappointed by the slow pace of change in the Company's investment practices since the start of the energy transition, as acknowledged by the Company in its SOP. Public Service's annual capital in its gas utility operations has risen by roughly 25 percent through 2023, or more than $120 million annually.[44] In an environment where sales will likely decline, large increases in capital spending will cause substantial rate and bill impacts in the future as the Company files rate cases seeking to recover the associated costs. Public Service now operates in a constrained budget environment, but we have yet to see any meaningful restraint in the Company's capital spending. We have strong concerns that continued capital spending at similar or even higher levels on behalf of the Company could hasten increases in rates in the coming years, which are already expected to be significant due to the Company's high level of spending and an expectation that sales may flatten or decline in the coming years, leading to significantly more fixed cost spread across a lower sales volume. These rate impact concerns have been exacerbated in this case by the Company's uncertainty and changing assumptions in providing a rate projection model that accurately reflects the Company's proposed capital investment and other plans, despite the Commission's clear request for information to assist in examining long-term rate impacts.[45]

(2) Questar Supply Project

54. Staff recommends the Commission disallow the inclusion of approximately $20 million of costs associated with the Questar Supply Project. Staff principally argues that the project cost is well above the $12 million threshold for the requirement that a utility secure a

[44] Hr. Ex. 169, 2017-2023 Public Service Gas Cap Expenditure Data, p. 1.
[45] Hr. Ex. 123, Matley Supplemental Direct, pp. 16-23; Hr. Tr. September 10, 2024, pp. 140:1–141:20.

Certificate of Public Convenience and Necessity ("CPCN") pursuant to Rule 4102 of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4. However, Staff also contends the project could affect ratepayers in adjacent utilities and shippers on both the Public Service and Rocky Mountain Natural Gas transmission systems because of its proximity to the Company's Rifle Gas Plant.[46] Accordingly, Staff recommends the Commission further review the project, directing Public Service to participate in the creation of a joint study between Staff, Rocky Mountain Natural Gas, and Public Service, with the results and any recommended future actions filed with the Commission within six months of a final decision in this Proceeding.[47] For instance, Staff contends the Rifle Plant, to which the project interconnects, is reaching the end of its service life and could impair the economic viability of that processing facility.[48]

55. In response, Public Service explains that the Quester Supply Project is intended to provide additional supply to Public Service customers, largely using existing infrastructure owned and operated by the Company. Public Service explains the project will work in tandem with two other pipelines, one of which serves only as a heating season baseload supply, and another, like the Questar Supply Project, that is used mainly to meet design day peak hour gas demand during the heating season.[49]

56. Public Service further argues the project was placed in service in August 2023,[50] and maintains this project is similar to other large capacity and reliability projects that the Company has brought forward in rate cases without needing to have secured a CPCN beforehand.

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[46] Hr. Ex. 404, Ramos Answer, pp. 30:17–31:8.
[47] Hr. Ex. 404, Ramos Answer, pp. 42:15–43:5.
[48] Hr. Ex. 404, Ramos Answer, p. 34:3-9.
[49] Witness Gardner corrects fig. ARG-D-9 at Hr. Ex. 105, Gardner Direct, p. 75 with fig. ARG-R-3 at Hr. Ex. 128, Gardner Rebuttal, p. 17.
[50] Hr. Ex. 128, Gardner Rebuttal, p. 12:4-5.

Notably, Public Service states the project was already under construction prior to recent changes to the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4.[51]

57. Public Service further states the project will not affect the capacity of the Rifle Gas Plant and clarifies that the Company wholly owns the project. Public Service rejects Staff's assertion that the Rifle Gas Plant has a questionable future, contending the plant is a "vital component of gas supply in the Mountain System supply portfolio in meeting demand during cold winter days."[52] Further, the Company clarifies that expenditures associated with the gas processed through the Rifle Gas Plant are independent of the Questar Supply Project. The Company asserts the Questar Supply Project will not, by itself, cause future incremental investments in the Rifle Gas Plant and that future capital expenditures are unknown. Again, Public Service asserts the primary concern at present is that the Questar Supply Project is necessary to address current supply constraints.[53] Therefore, the Company recommends the Commission reject Staff's request that it order a joint study.[54]

58. We deny Staff's request to exclude the Questar Supply Project from the calculation of the target revenue requirement in this Proceeding. We agree with Public Service that the rule that may have required that the Company secure a CPCN for the project is not applicable in this instance, primarily due to the timing of its construction. For investments occurring after implementation of Rule 4102, we expect a greater level of proactive oversight and evaluation of alternatives through the CPCN process, but, in this case, this project was timed prior to these requirements becoming effective. We are also left unpersuaded by Staff's argument that further review of the project is necessary. We find instead that Public Service has satisfied its burden to

[51] Hr. Ex. 128, Gardner Rebuttal, p. 13:3-8.
[52] Hr. Ex. 128, Gardner Rebuttal, p. 20:3-4.
[53] Hr. Ex. 128, Gardner Rebuttal, p. 20:15-21.
[54] Hr. Ex. 128, Gardner Rebuttal, p. 25:10-18.

show that the project is permitted to be included in the target revenue requirement in this Proceeding.

(3) Clarkson Street Project

59. Staff also recommends that the Commission disallow the inclusion of approximately $10 million of costs associated with the Clarkson Street Project. Staff portrays the project as posing a high public safety risk because it is an end-of-life replacement of a large diameter intermediate pressure pipe in a heavily populated area in downtown Denver.[55] Staff goes on to explain that the project is being implemented in four stages. The first two phases were completed in 2022 and 2023, with a combined investment of nearly $10 million as reflected in the target revenue requirement calculation in this Proceeding. The next two phases, scheduled for completion in 2025 and 2026, are expected to each be lower than the $12 million CPCN threshold in the Commission's Gas Rules, 4 CCR 723-4.[56] Nevertheless, Staff objects to the Company undertaking each of the phases of the project separately, stating that breaking the project up into phases circumvents CPCN filing rules. Additionally, Staff argues that large diameter pipe replacements in a densely populated urban area are not normal course of business operations and maintenance. Staff further notes that Public Service filed a petition for declaratory order in May 2024 related to the Clarkson Street Project, requesting a determination as to the necessity of a CPCN.[57] Staff contends that the Clarkson Street Project should not be included in rate base until that declaratory order is issued.

60. Public Service maintains that Clarkson Street Project constitutes work done in the Company's ordinary course of business and that phasing large projects such as this in congested

[55] Hr. Ex. 404, Ramos Answer, pp. 26:1–28:5.
[56] Hr. Ex. 404, Ramos Answer, p. 26:1-16.
[57] Proceeding No. 24D-0020G.

urban areas is typical industry best practice.[58] For instance, the Company points to the Blake Street Coupled IP project, which was active 2017 through 2020 in the area near Coors Field in Denver. Public Service states that similar project had a comparable cost of $27 million, was included in the PSIA rider, and no CPCN was necessary.

61. Public Service explains the pipe in the Clarkson Street Project was initially installed in the late 1940s and, as such, now poses critical safety concerns. As far as timing is concerned, the Company states the project began in 2022 under the PSIA, with an initial filing in November 2021, and that the second phase of the project was included in the Company's inaugural Gas Infrastructure Plan, filed in Proceeding No. 23M-0234G in May 2023.[59]

62. Public Service also explains that although two of the four phases of the Clarkson Street Project have been completed, the Company filed its petition for declaratory relief in Proceeding No. 24D-0220G "out of an abundance of caution."[60] The Company notes that Staff does not question either the need for the Clarkson Street Project nor the associated costs. The Company maintains it has adequately demonstrated on this record the need for and prudence of the Clarkson Street Project so as to warrant inclusion of these costs.

63. We indeed share many of Staff's concerns that large projects can potentially evade critical regulatory and planning requirements when divided into portions to be completed over time and that viewing such projects only as their subcomponents can obscure holistic considerations of alternatives. The Commission has, on multiple occasions, clarified that the gas planning rules, whether for inclusion in a Gas Infrastructure Plan or CPCN proceeding, intend to consider all related investments needed to ultimately serve the same need as part of one larger

[58] Hr. Ex. 128, Gardner Rebuttal, pp. 8:7-11.
[59] Hr. Ex. 128, Gardner Rebuttal, pp. 6:9–26:2.
[60] Hr. Ex. 128, Gardner Rebuttal, p. 10:5-8.

project for the purpose of identifying what projects must be reported within certain cost thresholds. Notwithstanding those general concerns, we make the limited finding on this record that the Company has met its burden to demonstrate the need for and prudence of these initial phases of the Clarkson Street Project, which were conducted prior to implementation of Rule 4102. For one, Public Service has shown that the Clarkson Street Project conducted up to and including the 2023 test year has been consistent with how other large projects in urban areas have been undertaken in the past to address safety concerns and other system factors. We therefore find it appropriate to allow Public Service to include the costs associated with the Clarkson Street Project prior to implementation of Rule 4102 in the calculation of the base rate revenue target in this Proceeding.

(4) Private LTE Project

64. Public Service includes $4.9 million in plant held for future use ("PHFU") for a Private LTE[61] wireless network it is developing for its Electric and Gas Departments to enhance its Supervisory Control and Data Acquisition ("SCADA") system capabilities. Public Service states this network is supplementary to the LTE network a third-party currently provides to the Company, serving as a backup system to reduce outages and dispatch of field workers when communications are lost. Additionally, the Company states that with this private network it can route natural gas distribution system information securely through its own network, not through the third-party's public communications network.[62] The Company contends this investment is appropriate for PHFU because the network has not yet been fully deployed.

65. Staff objects to including the Private LTE project in the rate base used to calculate the target revenue requirement in this Proceeding, because, according to Staff, there is no definite

[61] The Long-Term Evolution network ("LTE") is the set of wireless standards that was deployed prior to the 5G wireless standards that are now commonly used for cellular phone communications.
[62] Hr. Ex. 111, Scheller Direct, pp. 43:11-23, 44:1-5.

plan for when the project will be put into service and because the project does not meet the requirements of PHFU in Federal Energy Regulatory Commission Account 105.[63] Staff further notes that when the Company updated its test year data in its Rebuttal Testimony, the PHFU value for the project has more than doubled to $10.7 million.

66. UCA also objects to the inclusion of the Private LTE project as PHFU, alleging that the project is actually intended for the Company's electric service. Furthermore, UCA argues that since the project is not "used and useful," it should be excluded from rate base.[64] More generally, UCA also questions the need for Private LTE as a back-up system.

67. As further background, Public Service explains that it acquired the rights to the wireless spectrum in 2023 and that the Private LTE network will be deployed across counties on an established timetable.[65] Public Service also disagrees with Staff and UCA, explaining that the project benefits its natural gas customers in that it improves the resiliency and security of the gas SCADA system, which monitors both the electric and gas transmission and distribution systems. The Company elaborates, for instance, that the project will allow installation of devices, such as those used for gas pressure monitoring, onto the gas transport system without additional costs and will enhance information flow, improving reaction time and safety of the system, customers, and field employees.[66]

68. Public Service also argues that the project meets the requirements for inclusion in PHFU, because: it is valued at original cost; it is owned by Public Service and held for future use; and there is a plant for future use as a network communication platform. The Company also

[63] Hr. Ex. 400, Ghebregziabher Answer, p. 63:6-10.
[64] Hr. Ex. 500, Skluzak Answer, p. 106:3-7.
[65] Hr. Ex. 132, Scheller Rebuttal, p. 18:4-18.
[66] Hr. Ex. 132, Scheller Rebuttal, pp. 10:18–11:2.

disagrees with UCA's "used and useful" argument because that standard applies to plant in service, not PHFU.[67]

69. We agree with Public Service that the Private LTE Project meets the definitional requirements of PHFU for the purpose of establishing the target revenue requirement in this Proceeding. We are likewise satisfied that the project will be used in the future as described by the Company. We agree with Public Service that it is reasonable for the Company to develop its own network because this private network for resiliency and security of its SCADA system will be the primary system once deployed and the addition of devices on the private network will be without cost, reducing the cost of the third-party network. However, we are frustrated by the absence of key information that would have provided important information about any potential future costs associated with the project and the cost share between the gas and electric operating companies. While the intent of this project appears to be worth of the investment contained herein, additional costs that appear in the future may cause concern and could alter the Commission's view of the appropriateness of investments in this area, since those remain unknown or undisclosed by the Company at this time. The costs of the project thus deserve further scrutiny in the future when the investment becomes operational on the Company's gas system and is no longer being held for future use.

d. Cost of Capital

(1) Principles

70. Based on our consideration of the record in this rate case proceeding, we adopt three general principles to apply when determining the rate of return for Public Service's investments made to provide gas utility service to its customers.

[67] Hr. Ex. 133, Moeller Rebuttal, p. 42:3-5, 9-15.

71. First, we find it appropriate to evaluate the components of Public Service's authorized WACC in a combined, holistic manner to better understand the key interactive effects of ROE and capital structure, as well as the effects of depreciation and other elements in the establishment of the target base rate revenue increase. We undertake this holistic approach instead of evaluating these factors in isolation.

72. Second, in addition to traditional analyses of ROE and capital structure as presented in the parties' testimonies, we find it reasonable and appropriate to place meaningful weight on the revenues necessary to maintain Public Service's financial integrity, and to carefully consider analyses of Public Service's credit metrics as quantifiable, objective and specific measures of financial integrity.

73. Third, we conclude that Public Service should be evaluated as consistently as reasonably possible as an operating company, as there are important distinctions between an operating company and a holding company, evidenced by the unique attributes of Public Service and its parent holding company, Xcel Energy.

74. As discussed below, when these principles are applied, information on credit metrics and other aspects of the Company's financial integrity complement, but do not substitute, the traditional ROE and capital structure evaluation typically presented in a rate case. Any potential result must be viewed from the numerous objectives established as that will lead to rates that are just and reasonable for both consumers and investors. We find that applying these principles in this Proceeding is well supported by the record evidence.

(2) Return on Equity

75. Public Service asks that the Commission's decision in this Proceeding establish base rates that provide the Company with a reasonable opportunity to earn an ROE that is adequate

to attract capital at reasonable terms, sufficient to ensure its financial integrity, and commensurate with returns on investments in enterprises with similar risk. The Company notes that the key U.S. Supreme Court *Hope*[68] and *Bluefield*[69] decisions, as well as prior Commission decisions, recognize that it is important for the authorized ROE to satisfy these criteria.[70] Public Service thus proposes an ROE of 10.10 percent for its calculation of a base rate revenue target, which is a revision from its request of 10.25 percent in Direct Testimony.

(a) Public Service Direct Testimony

76. Through the Company's ROE witness, Ann Bulkley, Public Service initially suggests an ROE range extending from 10.25 percent to 11.25 percent as appropriate based on modeling results that ranged from 9.4 percent to 11.7 percent.[71] The Company's ROE calculations are based on numerous models including Constant Growth Discounted Cash Flow ("CG-DCF"), multi-stage Discounted Cash Flow ("MS-DCF"), Capital Asset Pricing Model ("CAPM"), Empirical CAPM ("ECAPM"), and Bond Yield Plus Risk Premium approaches. Ms. Bulkley develops her analysis based on a proxy group of five natural gas utility peers: Atmos Energy Corporation, NiSource, Spire, Northwest Natural Gas, and One Gas. Separately, Ms. Bulkley evaluated combination utilities which sell both gas and electricity. To develop her proxy groups, she applies screening criteria where companies were selected if they: pay consistent quarterly cash dividends (so the constant growth DCF model can be applied); have investment grade long-term issuer ratings from both Standard & Poor's (S&P) and Moody's; are covered by at least two utility industry analysts; have positive long-term earnings growth forecasts from at least two utility

[68] *Hope*, 320 U.S. at 591.
[69] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).
[70] Hr. Ex. 102, Bulkley Direct, p. 21 (citing Proceeding Nos. 11AL-382E and 11AL-387E; Decision No. C18-0736-I at ¶¶ 56-57 issued in Proceeding No. 17AL-0363G).
[71] Hr. Ex. 102, Bulkley Direct, p. 12; Hr. Ex. 102, Att. AEB-2.

industry equity analysts; derive more than 70 percent of their total operating income from regulated operations; derive more than 60 percent of regulated operating income from gas distribution operations; and were not parties to a merger or transformative transaction during the analytical periods relied on. Ms. Bulkley uses Beta values, representing metrics of stock price volatility, from two sources: Value Line and Bloomberg.[72] Public Service also revises its ROE calculation to include the cost of "stock flotation" representing the cost of issuing the securities.

77. Ms. Bulkley testifies that there are numerous examples in which utilities have experienced a negative market response related to the financial effects of a rate case. She notes that ALLETE, Inc., CenterPoint Energy Houston Electric, and Pinnacle West Capital Corporation each received credit rating downgrades following rate case decisions in the past few years for reasons that included below average authorized ROEs.[73] In other cases, she reports, stock analysts characterized recent low ROE authorizations in Connecticut and Illinois as "draconian" and "punitive" and associated stock prices subsequently fell significantly.[74]

78. Ms. Bulkley presents evidence showing core inflation had risen markedly over the past few years and that the Federal Reserve was committed to bringing down inflation through multiple increases to the federal funds rate which, in turn, led to increases to short-term and long-term bonds.[75] She also argues that utility share prices are inversely correlated to interest rates, and have generally underperformed the broader stock market.

(b) Staff Answer Testimony

79. In response to Public Service's presentation of its requested ROE, Staff witness Dr. Dipesh Dipu presents his own constant growth and multi-stage DCF models as well as CAPM

[72] Hr. Ex. 102, Bulkley Direct, p. 59.
[73] Hr. Ex. 102, Bulkley Direct, p. 18.
[74] Hr. Ex. 102, Bulkley Direct, pp. 19-20.
[75] Hr. Ex. 102, Bulkley Direct, pp. 24-30.

using the same proxy groups as the Company. While his analysis shows a range of ROE values from 6.24 percent through 9.27 percent, he recommends the Commission adopt a range for the Company's ROE extending from 8.75 percent to 9.25 percent and a specific value of 9.0 percent for the calculation of the base rate revenue target.[76]

80. Dr. Dipu calculates his own Beta for the proxy group by evaluating the daily stock price volatility relative to the market, not weekly or monthly comparisons as done by the array of economic forecasters referenced in the record (including Value Line, Bloomberg, S&P, Yahoo Finance, Zack's and LT data). Dr. Dipu also averages four unique historical periods including: one, three, five and 10 years of data, whereas the economic forecasters employed only a single historical period duration. Staff's values suggest up to a 50 percent reduction in Beta across the proxy group relative to the values applied by Public Service, Value Line and Bloomberg Beta.[77] Staff notes there is substantial variance in the Beta values among the professional economic sources and suggests the Company's selection of the two highest values is "worthwhile" for Commission consideration.[78] Staff's Beta calculation is at or lower than the lowest values available from the professional forecasters on the record (*i.e.*, S&P's) even after an adjustment factor that excluded one-third of the Beta calculation.

81. Dr. Dipu also questions the growth rates applied in the Company's MS-DCF model which were based on the growth in long-term historical gross domestic product values. Staff instead proposes using the projections from the Congressional Budget Office's economic growth forecasts specific to the energy sector, suggesting that the Congressional Budget Office has direct expertise in this area.[79] Staff evaluates Public Service's earnings and dividends per share

[76] Hr. Ex. 402, Dipu Answer, p. 6.
[77] Hr. Ex. 402, Dipu Answer, p. 17 tbl. DD-1 and p. 21 tbl. DD-4.
[78] Hr. Ex. 402, Dipu Answer, p. 17.
[79] Hr. Ex. 402, Dipu Answer, p. 38.

since 2019 to suggest that the Company cannot maintain the growth rates embedded in Ms. Bulkley's CG-DCF and MS-DCF models.

82. Staff also recommends the Commission order a separate, lower ROE for investments in new growth and capacity expansion gas projects.[80] Staff witness Erin O'Neill suggests these investments are counter to the state's policy objectives, and contends it is no longer just and reasonable for such investments to earn the same return as investments in safety or mandatory relocations. Ms. O'Neill claims that although that Company earns incentives on an array of activities, there is no financial incentive for the Company to actively manage or reduce investment in new gas infrastructure and no consequence for poor performance in addressing new growth.[81] She suggests annual new business investment has been steadily growing, more than doubling since the 2017 through 2020 period covered in the Company's 2020 gas rate case.[82]

83. Staff recommends the Commission set a ROE for new business and capacity expansion projects between the long-term cost of debt and the low end of the modeled ROE range of 7.71 percent proposed by Dr. Dipu. Ms. O'Neill suggests there is precedent for applying a cost-of-debt return to certain assets and such a value is reasonable because future growth investments could become stranded and later securitized at the cost of debt. However, Staff recommends a 7.71 percent ROE for growth investments resulting in a composite ROE of 8.89 percent.[83]

84. Staff witness Ms. O'Neill contends her proposal: creates a financial incentive to manage growth investments; creates a more symmetric ecosystem of incentives; does not create a disincentive for investment in safety; is consistent with long established state policy goals; does

[80] Hr. Ex. 401, O'Neill Answer, p. 5.
[81] Hr. Ex. 401, O'Neill Answer, p. 9.
[82] Proceeding No. 20AL-0049G.
[83] Hr. Ex. 401, O'Neill Answer, p. 16 tbl. ETO-3.

not place additional financial burden on new customers; and reduces the amount that the Company profits from a business that is driving climate change.[84] Ms. O'Neill also suggests the Company's revenue decoupling proposal (*i.e.*, the Revenue Stability Mechanism as discussed below) would further increase the need for such an ROE adjustment as Staff proposes as it would essentially eliminate regulatory lag and eliminate weather related sales risk. Staff also notes that the Commission approved a specific ROE for the Black Hills LM6000 generating facility in Proceeding No. 16AL-0326E and authorized a lower ROE for the initial regulatory balance for advanced meters, the Company's return on deferral costs for 2021 Winter Storm Uri, and initial return on wildfire mitigation expenses. Staff raises that the Commission also approved a ROE-adjusted performance incentive mechanism for the Colorado Power Pathway transmission project, decreasing ROE levels by 0.5 percent for every five percent (to a minimum of 7.8 percent) over budget the Company's final investment incurs.[85]

(c) UCA Answer Testimony

85. UCA witness Ron Fernandez contends Public Service's ROE calculation is not in line with recent Commission-approved ROEs nor representative of returns similarly situated utilities are seeing in the marketplace.[86] UCA recommends the Commission establish a principal ROE of 9.4 percent and an alternate ROE of 9.2 percent (*i.e.*, for a range extending from 9.0 percent to 9.6 percent), contingent on whether certain risk-reducing proposals are adopted by the Commission and on whether the Commission adopts UCA's suggestion for an additional 20 basis point reduction in ROE due to "affordability and public interest concerns."[87]

[84] Hr. Ex. 401, O'Neill Answer, pp. 18-19.
[85] Hr. Ex. 401, O'Neill Answer, pp. 32-33.
[86] Hr. Ex. 501, Fernandez Answer, p. 58.
[87] Hr. Ex. 501, Fernandez Answer, pp. 6-7.

86. Mr. Fernandez applies the CAPM, CG-DCF and MS-DCF models. He also evaluates recently authorized returns. UCA calculates its CAPM values based on historical market risk premium with stock market return and long-term bond data going back to 1926.[88] Mr. Fernandez contends Ms. Bulkley's CAPM analysis includes unrealistically high projected growth rates and market risk premiums that are well above the historical values. He suggests such an approach is neither reasonable nor sound over the long-term.

87. UCA conducts its calculations based on a unique proxy group relative to Public Service; UCA excludes NiSource and adds Chesapeake Utilities and New Jersey Resources.[89] Mr. Fernandez also takes issue with Public Service's use of 180-day average stock prices, suggesting such values were "stale," Ms. Bulkley's exclusion of certain data which he suggests indicates bias, and the Company's calculation of earnings growth rates among the proxy utilities.

88. With respect to stock flotation costs in ROE calculations, Mr. Fernandez contends investors do not consider flotation costs when they purchase stock in the open market and these costs have no bearing on the price an investor is willing to pay for a stock.[90] He notes that the vast majority of trading in a company's stock takes place in the secondary market on organized exchanges such as the New York Stock Exchange, and contends stock flotation costs are not incurred in such transactions. He also raises that the Commission has consistently denied the inclusion of flotation costs in the past.

[88] Hr. Ex. 501, Fernandez Answer, p. 62.
[89] Hr. Ex. 501, Fernandez Answer, p. 75.
[90] Hr. Ex. 501, Fernandez Answer, p. 101.

(d) Public Service Rebuttal Testimony

89. With respect to Staff's inference that Public Service only applied Betas from the highest sources available, Public Service witness Ms. Bulkley argues in rebuttal that data obtained from Bloomberg and Value Line is in fact widely accepted and that these are commonly utilized sources of financial data for investors. She notes that both Dr. Dipu and Mr. Fernandez rely on Value Line data for purposes of their respective DCF analyses. In addition, Ms. Bulkley notes, Mr. Fernandez relies on current Value Line betas for his CAPM analysis."[91]

90. With respect to Dr. Dipu's Beta calculated using daily stock prices, Ms. Bulkley responds that because the stocks of the proxy entities are thinly traded, the daily movement of their stock price is an inaccurate indicator of their perceived risk.[92] Ms. Bulkley argues that a less liquid stock will have a lower beta due to the fact that its share price does not move in tandem with the market given its lower trading frequency. She suggests that is why none of the economic forecasters utilize daily data to calculate betas.

91. With respect to UCA's use of historical data to calculate market risk premiums, Ms. Bulkley contends it is inappropriate to use historical data to estimate a forward-looking market return and that the historical market risk premium is unrelated to the current risk-free rate which violates the fundamental relationship between interest rates and the market risk premium.[93] Ms. Bulkley also suggests Mr. Fernandez's analysis is flawed in that it calculates the market risk premium by relying on the historical total return on long-term government bonds instead of the historical income-only return. She contends that because historical data incorporates negative market returns in certain years (such as 2008 when the financial crisis hit), the historical evidence

[91] Hr. Ex. 125, Bulkley Rebuttal, p. 43.
[92] Hr. Ex. 125, Bulkley Rebuttal, p. 40.
[93] Hr. Ex. 125, Bulkley Rebuttal, p. 44.

"runs counter to the theory of equity risk premium" and that one year reduced the historical market risk premium for the prior 80 years by 60 basis points.[94]

92. With respect to UCA's proxy group, Ms. Bulkley argues that Mr. Fernandez applies a screen to establish comparability that includes entities that are investment grade credit rating or equivalent. Ms. Bulkley notes that only the loose standards applied to "or equivalent" facilitates the inappropriate inclusion of Chesapeake in his proxy group, and that Mr. Fernandez excluded Chesapeake in his proxy group in the Company's last rate case.[95]

93. Public Service further rebuts Staff witness Ms. O'Neill's proposal for differentiated ROEs as inconsistent with financial theory, recently authorized ROEs, the ranges of investor-required returns as established by the witnesses in this Proceeding, and the *Hope* and *Bluefield* principle of authorizing a return on investment that is consistent with the return on other investments of comparable risk.

(3) Cost of Debt

94. In its Rebuttal Testimony, Public Service suggests the use of a cost of long-term debt of 4.27 percent[96] and a cost of short-term debt of 5.81 percent[97] for calculating the WACC rate of return. The Company's long-term debt calculation includes two bond issuances conducted in April 2024 (*i.e.*, post-test year) totaling $1.2 billion.

95. UCA recommends a long-term cost of debt of 4.04 percent based on debt issued up to and including the 2023 test year.[98] UCA also recommends that Public Service not be allowed to include short-term debt in its capital structure, and suggests the costs of short-term debt and

[94] Hr. Ex. 125, Bulkley Rebuttal, p. 47.
[95] Hr. Ex. 125, Bulkley Rebuttal, pp. 27:13–28:2.
[96] Hr. Ex. 126, Johnson Rebuttal, p. 29.
[97] Hr. Ex, 103, Johnson Direct, p. 8.
[98] Hr. Ex. 501, Fernandez Answer, p. 50.

so-called short-term credit facility fees are moot.[99] UCA contends the United States is currently experiencing an inverted yield curve that is anomalous and not reflective of future short-term interest rates; accordingly, it is inappropriate to include short-term debt in a utility's capital structure at this time. UCA further contends the current interest rate environment significantly overstates the cost of short-term debt. If the Commission approves short-term debt in the capital structure, UCA suggests it should approve a rate of 1.0 percent.[100]

96. Staff contends the Commission should evaluate the cost of debt, as well as WACC, on a post-tax basis, otherwise the benefit of the interest tax shield represented by corporate debt would be ignored.[101] At hearing, Staff witness Dr. Dipu agreed that the interest tax shield associated with Public Service's debt is treated as part of the Company's revenue requirement and is appropriately excluded from the Company's cost of debt calculation.

97. With respect to UCA's suggestion that short-term debt should be excluded from the capital structure calculation, Public Service replies that UCA previously argued for the inclusion of short-term debt, citing UCA witness Mr. Fernandez, who called it "a material and permanent source of capital for the Company."[102] Public Service explains that the Company uses its short-term debt to fund the ongoing operations that it is seeking recovery of in this Proceeding. Public Service states that short-term debt is included in the capital structure of other Xcel Energy subsidiaries and authorized by numerous other regulatory jurisdictions across the United States. Public Service further notes that Staff has strongly supported including short-term debt into the capital structure of Public Service and other regulated utilities in recent rate case proceedings.[103]

[99] Hr. Ex. 501, Fernandez Answer, p. 51.
[100] Hr. Ex. 501, Fernandez Answer, p. 57.
[101] Hr. Ex. 402, Dipu Answer, p. 47.
[102] Hr. Ex. 126, Johnson Rebuttal, p. 34:9-21 (citing Hr. Ex. 501, Fernandez Answer, p. 34:14-22).
[103] Hr. Ex. 126, Johnson Rebuttal, p. 34:9-21.

98. Public Service suggests that UCA's recommendation of 1.0 percent cost of short-term debt is inappropriate and does not reflect the Company's current cost of short-term debt which is "over 5.0 percent."[104] Public Service instead contends that a 1.0 percent cost of short-term debt is not achievable in the market and not even remotely close to the reality of current market conditions.[105]

(4) Equity Ratio and Capital Structure

99. For the purpose of deriving the WACC rate return, Public Service proposes a capital structure consisting of 55 percent equity, 43.18 percent long-term debt, and 1.82 percent short-term debt. The Company requests that the Commission pick a single equity ratio point rather than a range.[106] The Company further asks that if the Commission approves a range for the equity ratio within the capital structure and a range for the authorized ROE, that the full use of both authorized ranges mathematically support the calculation of the authorized WACC.

100. With respect to the 52 to 55 percent equity ratio range approved by the Commission in the 2022 Gas Rate Case, Public Service witness Paul Johnson notes the Company managed to a 55 percent equity ratio in lieu of a higher ROE.[107] This demonstrates, according to Mr. Johnson, the Company's commitment to maintaining its credit quality in an efficient manner.

(a) UCA Answer Testimony

101. UCA suggests the Commission should evaluate parent company Xcel Energy's capital structure rather than the artificial capital structure that Xcel Energy has allocated to Public Service. According to UCA, this approach would eliminate any intra-company subsidies and base the capital structure on how Public Service is actually financed. UCA notes that the equity

[104] Hr. Ex. 126, Johnson Rebuttal, p. 35.
[105] Hr. Ex. 126, Johnson Rebuttal, p. 35.
[106] Hr. Ex. 103, Johnson Direct, p. 34.
[107] Hr. Ex. 126, Johnson Rebuttal, pp. 26-27.

ratio of Xcel Energy has steadily declined from 46.5 percent in 2014 to 40.9 percent in 2024.[108] UCA argues that, by allocating the most conservative and costly capital structure among its operating companies to Colorado, Xcel Energy extracts additional revenue from the state's ratepayers to the benefit of its subsidiaries in other states and its investors.[109] UCA notes that Public Service's affiliate in Minnesota, *i.e.*, Northern States Power-Minnesota, is assigned an equity ratio of only 52.5 percent.

102. UCA further suggest that the Commission move to a "pass-through" capital structure over three steps. The first step, represented by this Proceeding, would implement a capital structure representing 51.4 percent equity and 48.6 percent debt. Step two, for a future rate case, would reduce equity to 46.1 percent and increase debt to 53.9 percent. And the third step would decrease equity to 40.9 percent of total capital and increase debt to 59.1 percent of total capital (which UCA argues mirrors Xcel Energy's capital structure as of December 2023).[110]

103. UCA also suggests the Commission approve, as an alternative to its three-step "pass through" capital structure, the Company's "economic capital structure," a lower value recognized by the rating agencies.[111] Mr. Fernandez notes that value for Public Service is 53.14 percent equity, 48.16 percent debt.

104. UCA further argues that maintaining Public Service's current A- credit rating is an unnecessary luxury at ratepayers' expense.[112] Mr. Fernandez suggests that the industry average rating for utilities is somewhere between a BBB and BBB+, and thus, Public Service has been maintaining a credit rating one or two notches above the industry average which is only a cost to

[108] Hr. Ex. 501, Fernandez Answer, p. 18.
[109] Hr. Ex. 501, Fernandez Answer, p. 13.
[110] Hr. Ex. 501, Fernandez Answer, p. 23 tbl. RAF-8.
[111] Hr. Ex. 501, Fernandez Answer, p. 31.
[112] Hr. Ex. 501. Fernandez Answer, p. 27:3-9.

ratepayers. UCA contends utilities with lower bond ratings of BBB+ or even BBB are able to access credit without delay and even in times of distress (such as the 2021 Winter Storm Uri). Mr. Fernandez also suggests the credit opinions are subject to bias as the Company, as a debt issuer, pays for the credit opinions which creates a perverse incentive.

(b) Staff Answer Testimony

105. Staff suggests that Public Service's proposed equity ratio is far higher than the other entities in the two proxy groups developed by Public Service.[113] Staff instead recommends that the Commission adopt an equity ratio of 50 percent because it is close to the mid-point between industry averages and Company's proposed ratio. However, "upon reconciliation of other findings," Staff recommends the Commission adopt an equity ratio of 52 percent.[114]

(c) Public Service Rebuttal

106. Public Service contends UCA's recommendations do not represent the Company's actual capital structure either at a point in time or on an average basis. Public Service witness Mr. Johnson suggests it is also inconsistent with how Public Service operates its business and how it is viewed by credit rating agencies. In addition, Mr. Johnson adds, UCA's proposals would markedly deteriorate the Company's cash flow and likely result in a several notch downgrade in credit ratings and have a fundamental change in investor perspective of Colorado's regulatory environment.[115]

107. With respect to its affiliate operating companies, Mr. Johnson suggests that the comparisons that UCA makes are not appropriate. For example, even though Northern States Power-Minnesota has a markedly lower equity ratio, that operating company enjoys a lower cost

[113] Hr. Ex. 402, Dipu Answer, pp. 54-55 tbls. DD-18, DD-19.
[114] Hr. Ex. 402, Dipu Answer, p. 56:9-11.
[115] Hr. Ex. 126, Johnson Rebuttal, pp. 6-7.

of debt and a higher credit rating due to factors like interim rate availability and forecasted test years which reduce regulatory lag.[116]

108. Mr. Johnson also takes issue with Staff's approach to selecting its proposed equity ratio, noting that it incorporated an evaluation of holding companies when Public Service is clearly an operating company. Mr. Johnson suggests this is akin to "comparing apples and oranges."[117] Mr. Johnson instead offers that Public Service's 55 percent equity ratio is quite normal amongst utility operating companies, which according to his analysis, have equity ratios ranging from 45 through 62 percent.

109. Mr. Johnson rebuts UCA's reference to economic capital structure, and notes that metric imputes off-balance sheet debt such as lease obligations to determine its value. He further suggests that if the Commission set regulatory capital structure at that rate, the rating agencies would simply make an additional adjustment to account for off-balance sheet obligations from the new baseline set by the Commission.[118]

110. Public Service witness Mr. Johnson argues that Public Service's current A- credit rating provides it access to capital markets even in difficult times and lowers the cost of bond issuances. Mr. Johnson contends it has, and would again, take years to repair the Company's perceived creditworthiness with investors should a downgrading occur.[119] He further contends it is not advisable to have credit metrics on the threshold of a downgrade, because it leaves very little flexibility for a company to respond to unexpected events.[120] The Company suggests setting

[116] Hr. Ex. 126, Johnson Rebuttal, p. 21.
[117] Hr. Ex. 126, Johnson Rebuttal, pp. 27-28.
[118] Hr. Ex. 126, Johnson Rebuttal, pp. 23-24.
[119] Hr. Ex. 126, Johnson Rebuttal, pp. 6-7.
[120] Hr. Ex. 126, Johnson Rebuttal, p. 8.

revenue requirements about 200-300 basis points above a 19 percent threshold to ensure general credit stability.[121]

111. Public Service also suggests UCA's pass-through capital structure concept should be disregarded. Mr. Johnson notes the Company's credit ratings and cost of borrowing are largely based on the analysis of the stand-alone entity, stating Public Service issues its own debt and financial statements. In addition, Mr. Johnson raises that the Company is separately regulated in Colorado, whereas Xcel Energy and its regulated utility subsidiaries and non-regulated subsidiaries operate in their own unique environments. In addition, Mr. Johnson maintains that rating agencies perform a company-specific, top to bottom review of Public Service to determine credit quality."[122] Mr. Johnson also contends that UCA witness Mr. Fernandez makes no attempt to quantify any of the impacts his recommendations would have on the cash flow and credit metrics of the Company. Mr. Johnson also contends UCA conflates Xcel Energy, which has an equity ratio exceeding 70 percent, and Xcel Energy's consolidated financials, which includes the debt raised by individual operating companies such as Public Service as well as unregulated subsidiaries of Xcel Energy.

(5) Credit Metrics

112. In this Proceeding, Public Service offers two different methods of projecting the Company's credit metrics. Both evaluations view Public Service broadly, including both gas and electric operations.

113. First, the Company provides a consolidated financial model upon which it conducted seven scenario evaluations. The range of scenarios include: the Company's own

[121] Hr. Ex. 126, Johnson Rebuttal, p. 28.
[122] Hr. Ex. 126, Johnson Rebuttal, p. 18.

proposed ROE and capital structure values; Staff's and UCA's proposed ROE and capital structure values; the ROE held static at 9.2 percent; and as if the instant rate case was not filed.[123] Public Service's consolidated financial model suggests that the proposals from Staff and UCA would reduce the Company's 2025 CFO pre-WC / debt ratio (*i.e.*, its projected cash flow from operations divided by its debt obligations) to exactly or just slightly above the 19 percent threshold employed by Moody's, which "would leave the Company with, at best, minimal levels of financial cushion to withstand adverse, unforeseen events."[124] Public Service notes that UCA's proposed pass-through capital structure, which ultimately establishes an equity ratio near 40 percent, "would cause significant financial harm to Public Service, likely resulting in a multiple notch downgrade by Moody's."[125] In the scenario where ROE is held at 9.2 percent, the Company's projected 2025 CFO pre-WC / debt ratio is 21.0 percent, or 200 basis points above the 19 percent threshold generally employed by Moody's.[126]

114. Second, Public Service presents the "Levers Model." This model is simpler than the Company's more formal consolidated financial model; nonetheless, it produces consistent results with the formal modeling and allows the model user to assess a myriad of combinations with respect to ROE, capital structure, accelerated depreciation, and other factors (referred to as Levers) that impact the Company's creditworthiness.

115. Through testimony, Public Service submits into the record the recent credit opinions from the rating agencies it subscribes to: Moody's, S&P, and Fitch. Public Service witness Mr. Johnson also describes the guidelines these Companies issue in evaluating their credit ratings. For instance, Mr. Johnson notes that the key credit metric Moody's employs when

[123] Hr. Ex. 126, Johnson Rebuttal, p. 13 tbl. PAJ-R-1.
[124] Hr. Ex. 126, Johnson Rebuttal, p. 13.
[125] Hr. Ex. 125, Johnson Rebuttal, p. 14.
[126] Hr. Ex. 126, Johnson Rebuttal, p. 13 tbl. PAJ-R-1.

conducting its credit ratings is known as cash flow from operations less working capital to debt ratio, referred to as CFO pre-WC / debt ratio.[127] Mr. Johnson further points out that Moody's noted in its recent credit opinion of the Company that "[t]he ratings could be downgraded if there is deterioration in credit supportiveness… specifically if it CFO pre-W/C to debt ratio stays below 19% on a sustained basis."[128] That is, Moody's threshold requires the Company's cash flow from operations to maintain a long-term level of at least 19 percent relative to the size of its debt obligations. Moody's also considers other credit metrics (which similarly assess the Company's ability to meet oncoming debt obligations) as well as subjective criteria such as regulatory support, business risk and other factors.

116. S&P and Fitch employ similar credit metric evaluations though these entities are not as transparent as Moody's of the credit metric thresholds between ratings.[129] S&P and Fitch give Public Service an equivalent credit rating as Moody's; however, S&P recently placed the Company on credit watch due to recent wildfire events and the litigation risk associated with those events.[130]

(6) Weighted Average Cost of Capital

117. Overall, based on our review of the extensive evidence presented by the parties related to determining Public Service's cost of capital and upon applying the principles described above, we find that a WACC value of 7.0 percent will result in just and reasonable rates that are in the public interest. Public Service produced a range of modeling scenarios that evaluate different ROE and capital structure values; we find such analyses and the corresponding Levers Model

[127] Hr. Ex. 126, Johnson Rebuttal, p. 13. The Commission notes that both Moody's and S&P evaluate the Company's financial health based on four different credit evaluation calculations. Moody's and S&P's metric differ slightly, but generally measure the Company's ability to meet its debt obligations.
[128] Hr. Ex. 126, Johnson Rebuttal, p. 13.
[129] Hr. Ex. 126, Johnson Rebuttal, pp.18-19.
[130] Hr. Ex. 126, Att. PAJ-19, p. 1.

produce valuable insight into the Company's financial integrity when the WACC is set at 7.0 percent for calculating the target base rate revenue requirement in this Proceeding.

118. We conclude that the pre-existing ROE range from 9.2 percent to 9.5 percent and the equity ratio range from 53 percent to 55 percent are well within the credible record evidence presented by the parties in this Proceeding. We also conclude that, upon applying the principles described above, maintaining the ROE range of 9.2 percent to 9.5 percent and an equity ratio range between 53 percent to 55 percent—ranges established by the Commission in the 2022 Gas Rate Case—the Company's financial health is projected to be robust and supportive of Public Service's current credit rating. Specifically, a combination of 9.2 percent ROE and 55 percent equity ratio produces a CFO pre-WC / debt ratio of roughly 21 percent, two hundred basis points above the threshold defined by Moody's. We find that this will provide the Company with a more than reasonable cushion by which to maintain its credit rating, and that such considerations are appropriately included in our decision making in the instant proceeding. We further note that while the ROE and equity ratio are highly interrelated and both impactful to the Company's financial health, the equity ratio has an oversized impact on the Company's credit metrics. Shifts in equity ratio (and thus, capital structure generally) cause greater impacts to the Company's credit metric relative to shifts in ROE necessary to produce the same reduction in revenue requirements. In contrast, requiring lower levels of equity and higher levels of debt, as suggested by UCA and Staff, produce two results: revenue requirements (in essence, cash flows) decline while the level of debt increases simultaneously. We thus have concern that reducing the equity ratio to approximately 52 percent as UCA and Staff suggest as a result in this Proceeding, and further lowering the equity ratio to match that of parent Xcel Energy (currently 40.9 percent) in a future proceeding, could place financial strain on the Company.

119. With respect to UCA's contention that the Company's current credit rating of A- is, in essence, an expensive luxury maintained at ratepayer expense, there is no in-depth analysis on this record demonstrating that ratepayers would benefit from targeting a lower credit rating. We also note that Public Service's gas and electric operations are expected to invest billions of dollars over the foreseeable future, and that a reduction in creditworthiness would impact the cost of that financing obligation. We also find merit in the Company's argument that any downgrade, if implemented by one or more rating agencies, could take significant time to reverse. Overall, at the current time, based on the evidence in this record, we find the Company's current A- credit rating provides general financial stability and access to capital at reasonably low cost and is appropriately targeted through this Decision.

120. With respect to the cost of long-term debt, we accept the Company's proposal in its Rebuttal Testimony to set long-term debt at 4.27 percent (thus including debt issuances made in 2024). As we have found in other recent rate cases, debt issuances that are known and quantifiable are generally appropriate for inclusion in the cost of debt calculation; this should remain true in periods where the marginal cost of debt is higher than the average (as in the instant Proceeding) as well as when the marginal cost of debt is lower than the average. Thus, we find the Company's calculation of its long-term debt costs reasonable and appropriate.

121. With respect to the inclusion of short-term debt in the determination of the WACC, we also reject UCA's suggestion to eliminate short-term debt from the capital structure, as we believe short-term debt represents an ongoing and legitimate source of capital necessary for the Company to operate its business for the benefit of ratepayers. We further agree with Public Service that UCA's proposed rate of 1.0 percent is neither a realistic nor reasonable representation of the Company's cost to acquire such capital in the current market or over the expected period these

rates will be in effect. However, we agree with UCA that using a cost of short-term debt at the 5.81 percent level as proposed by the Company based on the cost of such capital acquired during the test-year is not reasonably representative of the cost of short-term debt going forward, given recent actions and indications by the Federal Reserve to reduce interest rates. Because we expect the cost of short-term debt incurred by the Company to be below the 5.81 percent level when the new base rates established by this Decision take effect, the full use of the authorized ranges for ROE and the equity ratio will mathematically support the calculation of the authorized WACC at 7.0 percent.

e. Depreciation

122. Public Service's COSS for the 2023 test year presented in Direct Testimony includes an annual plant depreciation expense of approximately $230 million. Approximately $186 million of that total depreciation expense relates to the Company's gas delivery system.[131] The gas system's depreciation expense is based on the same approach to calculating depreciation expenses approved by the Commission in the Company's 2022 Gas Rate Case. Public Service witness Mark Moeller explains that Public Service applies the Equal Life Group approach to all asset-specific costs and Average Life Group approach to corporate-wide costs (such as overhead).[132]

123. With the exception of how the Company treats "net salvage values," Staff generally supports continuation of current depreciation practices with the understanding that a new depreciation study is due by February 2025. Staff also suggests the Commission order a $15 million increase in depreciation expense as a "gradualist" approach in order to recognize the

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[131] Hr. Ex. 133, Moeller Rebuttal, p. 13.
[132] Hr. Ex. 114, Moeller Direct, p. 19.

increasing likelihood of shorter than expected lifetimes or reduced throughput in the future.[133] Public Service does not oppose Staff's proposal for an increase in the depreciation expense used to set the target base rate revenue increase, but the Company clarifies that it has not included Staff's recommendation in its calculation of base rate revenue requirements.[134]

124. Furthermore, in its Supplemental Direct Testimony, Public Service contends that if the Commission requires the Company to assume a 2050 end of life for the entire gas system, depreciation rates in this Proceeding would roughly double. For example, depreciation of 2023 investments would increase from $16.5 million assuming normal life to $29.9 million assuming a 2050 end of life (including recovery of both initial investment and retirement expenses).[135]

(1) Net Salvage Value

125. Public Service argues that the best way to ensure the Company has funds reserved for the decommissioning of assets when they are retired is to set depreciation rates based on the best available assumptions and data regarding the lives of those assets.[136] To pay for the future liability of asset retirement (also known as decommissioning or removal), Public Service depreciates, on a system average basis, roughly $1.58 for every $1.00 of initial investment.[137] The record further indicates the total net salvage value of infrastructure currently is $3.7 billion[138] and the Company has built up a Cost of Removal reserve of $413 million.[139] That value represents a future obligation Public Service owes to its customers and is often referred to as "negative rate base."

[133] Hr. Ex. 407, Rivera Lugo Answer, p. 17.
[134] Hr. Ex. 124, Berman Rebuttal, p. 45.
[135] Hr. Ex. 121, Moeller Supplemental Direct, p. 21 tbl. MPM-SD-1.
[136] Hr. Ex. 121, Moeller Supplemental Direct, p. 6.
[137] Hr. Ex. 123, Att. RAM-4C, p. 2.
[138] Hr. Ex. 407, Rivera Lugo Answer, p. 27.
[139] Hr. Ex. 407, Rivera Lugo Answer, p. 28.

126. Public Service witness Mr. Moeller offers four reasons to include removal costs in depreciation rates. First, intergenerational equity; that is, customers who benefit from use of an asset help pay for the costs of its retirement. Second, to spread the recovery of retirement costs over the life of the asset rather than impose a direct rate increase when removal costs are incurred at the time of an asset's retirement. Third, the collection of all costs associated with an asset over time assist with utility cash flows during those periods. Fourth, the collection of removal costs over the life of the asset is consistent with widely accepted Generally Accepted Accounting Principles and regulatory accounting principles and is long-standing past practice for both gas and electric Colorado utilities.[140]

127. Public Service also explains that negative rate base is the result of timing differences between when removal costs are collected through depreciation and when they are expended to retire assets.[141] Mr. Moeller suggests this is common in the electric business when a generating asset is retired and is quite appropriate for *individual or small groups of assets* as they are retired over time. Nevertheless, with respect to the Company's *overall* gas rate base, Public Service says it is highly unlikely to turn negative, especially if depreciation rates align with the lives of utility assets as they are retired over time. Mr. Moeller says he is not aware of any situation involving negative rate base for a utility's natural gas system as a whole.[142] He further gives reasons why this is unlikely:[143] new capital investments are not all set to a 50-year life, they may range anywhere from 3 to 80 years depending on the nature of the asset; negative rate base can be avoided by gradually retiring gas plant over time, at the current or accelerated basis, as opposed to *en masse* at the end of life for a system; and the purpose of recalculating depreciation

[140] Hr. Ex. 133, Moeller Rebuttal, p. 21.
[141] Hr. Ex. 121, Moeller Supplemental Direct, p. 15.
[142] Hr. Ex. 121, Moeller Supplemental Direct, p. 6.
[143] Hr. Ex. 121, Moeller Supplemental Direct, pp. 16-17.

rates from time to time is to align them with new information regarding the likely life of the relevant assets.

128. Criticizing Public Service's approach to addressing plant removal, Staff witness Luis Rivera Lugo argues that current depreciation rates are far higher than recent historical costs of removal. He further contends Public Service can use the excess funds collected through the depreciation expense for net salvage "[f]reely, in whatever form or manner they choose to, and not necessarily to pay for any costs of removals currently being incurred."[144]

129. Staff thus recommends the Commission order Public Service to reclassify the pre-collected depreciation reserve to a separate regulatory liability account. This new account would be exclusively used to charge actual costs of removal incurred until completely depleted. Staff further suggests the Commission allow the target revenue requirement to include the ten-year average of actual costs of removal incurred, or approximately $13 million per year, as an ordinary expense in future rate cases. Mr. Rivera Lugo also suggests Public Service should remove any estimated negative net salvage from the computation of depreciation accrual rate in the upcoming depreciation study.[145]

130. Staff further suggests that the Commission lower costs to current customers, at least with respect to net salvage, by expensing future retirement costs as they occur. Staff clarifies, however, this change should not be implemented until the Company's new depreciation study is submitted next February.[146] Staff further suggests net salvage is regularly expensed by utility regulatory commissions around the country and included modest references to decisions rendered

[144] Hr. Ex. 407, Rivera Lugo Answer, pp. 23-24.
[145] Hr. Ex. 407, Rivera Lugo Answer, p. 31.
[146] Hr. Ex. 407, Rivera Lugo Answer, p. 31.

in Pennsylvania, Missouri, Illinois, California, and Oklahoma. Mr. Rivera Lugo says this is not an exhaustive list and many more examples could exist.[147]

131. In response, Public Service contends that, except for one piece of testimony, Staff provided no specific laws, Commission decisions, court rulings, or other documents to support the contention that expensing retirement costs is a widespread practice. With respect to the one reference Staff provided as supporting record evidence, a decision by the Missouri Public Service Commission, Public Service witness Steven Berman points out the commission later reversed its net salvage policy in 2024 and returned "to traditional accounting methods."[148] He also provided evidence that Mr. Rivera Lugo's other references were limited in scope and do not represent a material shift in net salvage treatment.

132. Mr. Moeller also contends Staff's proposed solution is flawed and will leave customers open to significant, one-time actual removal costs in the future. He suggests that the existing reserve account is effectively already a regulatory liability for both U.S. Securities and Exchange Commission and Federal Energy Regulatory Commission reporting purposes. Mr. Moeller explains, the dollars are separately classified and are directly reduced by spend on removal activities for gas system assets. Mr. Moeller also contends that Staff's proposal fails to recognize that current depreciation rates are designed to serve the current population, while actual removal costs are based on infrastructure designed to serve the population when the pipe was installed. According to Mr. Moeller, Colorado's population has tripled, and household sizes have declined by 29 percent since 1964 and there are nearly four times as many households served by the Company as compared to sixty years ago.[149]

[147] Hr. Ex. 407, Rivera Lugo Answer, p. 29.
[148] Hr. Ex. 124, Berman Rebuttal, p. 48.
[149] Hr. Ex. 133, Moeller Rebuttal, p. 29 tbl. MPM-R-1.

133. Public Service offers that an alternative method to addressing net salvage values is through the use of a legally separate trust fund, which would prevent negative rate base as the trust itself and the obligations it funds are outside of rate base. Logistically, the Company would establish the external trust and hire a trustee and a separate entity to manage the funds in the trust. The Company argues, however, that a reserve fund would be highly unusual and complex for natural gas assets. Mr. Moeller explains, for instance, the trust must earn its own return, and cautions that taxes and the need for a conservative investment mix may reduce the trust's investment returns.[150] The Company further contends the current protocol facilitates the ratepayers receive a return at the Company's WACC as the Cost of Removal reserve represents funds the Company does not have to raise.[151]

134. Public Service further argues that the trust fund could fundamentally harm the Company's financial integrity at the same time in which it must continue to serve gas utility customers. Along these lines, Public Service witness Mr. Johnson describes a potentially detrimental impact on Company cash flows and credit metrics aligned with either moving the current decommissioning reserve or future expenses to a trust. He describes four future scenarios to calculate impact to Public Service's credit metrics,[152] but concludes that the Company cannot be certain how the rating agencies would model such a methodology.[153]

(2) Depreciation Expense, Separate Removal Trust, and Future Filing Requirements

135. We find Public Service's approach to funding decommissioning expenses disconcerting because it results in a growing and potentially massive future liability. Under the

[150] Hr. Ex. 121, Moeller Supplemental Direct, p. 26.
[151] Hr. Ex. 121, Moeller Supplemental Direct, p. 26.
[152] Hr. Ex. 119, Johnson Supplemental Direct, p. 16 tbl. PAJ-SD-4.
[153] Hr. Ex. 119, Johnson Supplemental Direct, p. 14.

current function, the Company intakes the estimated costs for decommissioning, the net salvage value, throughout the depreciation of the asset, however the money taken in for this purpose actually serves as free cash flow for the Company, with no restrictions as to its use. Based upon our understanding from the Company's description, funds are not being saved or reserved for the purpose of decommissioning the assets for which they are collected. This outcome is further troubling when combined with the projection for future sales reductions due to a variety of market circumstances, combined with local, state and federal policy initiatives designed to lower carbon and methane emissions. For example, the Commission recently approved considerable financial resources to implement beneficial electrification and demand-side management technologies that we expect to reduce the reliance on natural gas.[154] Lower sales could lead to higher rates for customers who remain on the gas system, creating a potential feedback loop that incentivizes customers to leave it at increasing rates. The Commission is troubled by the Company's lack of concern about an accounting system that has not contemplated its own function and impact in a potential future where annual decommissioning could exceed capital additions, and has serious doubts that the funds collected from customers for the purpose of decommissioning would be available for said purpose when it comes time to decommission the assets. In that context, Public Service's future liability to pay for infrastructure retirement represents a significant and problematic financial risk.

136. Accordingly, we find it necessary to limit ratepayer's exposure to uncertain future asset retirement liabilities by requiring Public Service to establish a separate trust account to begin to better address the anticipated costs of removal. Specifically, we direct the Company to place $15 million per year, collected through the depreciation expense as presently calculated and

[154] *See* Decision No. C24-0397 issued in Proceeding No. 23A-0392EG (June 10, 2024).

included in the calculation of the test year revenue requirement, into a separate trust account. The trust should be managed in a manner so that the funds are roughly expected to grow annually at or close to the WACC as established in this Decision. Funds in the trust are to be held for future asset retirement obligations and can be released for that purpose only when, over a continuous twelve-month period, retirement expenses (*i.e.*, removal costs incurred) exceed the portion of funds received through base rate revenue collections for removals. Simultaneously, to help offset the loss to free cash flow available to the Company through our funding of the trust, we authorize Public Service to increase the annual depreciation expense used to calculate the annual target revenue requirement in this Proceeding by $15 million. In addition to preserving the same level of cash flow for the Company's benefit, this increase in depreciation acknowledges Staff's arguments about the high likelihood of a decrease in the anticipated life of new gas assets, given the realities associated with competition from highly efficient electric options and a variety of policies supporting the same.

137. We further note that the record includes no forecast of the future total Cost of Removal reserve or of the components that will comprise it. The lack of this information limits our ability to fully comprehend the issue of the negative impact of net salvage on rate base over time and its impact on the Company's long-term financial integrity and credit metrics, especially under future scenarios that vary from the historical growth pattern on the system. We therefore conclude it is necessary and reasonable to direct Public Service, as part of the Company's upcoming depreciation study, to produce a 25-year forecast in executable format that projects forward annual decommissioning costs, annual retirement depreciation expense accrued, the total Cost of Removal reserve, the debt and equity levels of the Company as an operating utility, the operating company's credit metric, and overall retail rate impacts over the forecast period.

This extended forecast should be capable of incorporating various depreciation and net salvage value scenarios evaluated through the depreciation study so that the Commission can place the issue of the long-term net salvage and impact on the Company's general financial health into proper context.

138. We also find it necessary to direct the Company, as part of its upcoming depreciation study, to present several future scenarios that incorporate potential reductions in natural gas throughput due to adoption of electrification technologies, subsequent rate impacts due to reduced throughput in gas service, gas customer termination of service, and further elasticity effects.

139. We also direct the Company, as part of its depreciation study, to explain its specific assumptions with respect to asset decommissioning (*i.e.*, for each asset category, what proportion of assets are retired in place vs. physically removed) as well as to provide a full analysis on the impact that changes in expected asset life would have on projected net salvage costs.

f. Annual Incentive Program

140. Public Service requests recovery of $5.3 million in Annual Incentive Program ("AIP") expenses, reasoning that incentive compensation reduces labor costs by lowering base pay which is subject to annual escalation rates. The Company states the AIP produces a market competitive total cash package when it is added to base pay.[155]

141. Public Service explains that it uses the AIP to align employees' goals with the Company's corporate and business goals. The Company further explains the AIP is a tool for

[155] Hr. Ex. 108, Deselich Direct, p. 32:1-6.

recognizing and rewarding exempt non-bargaining employees for their contribution to the achievement of reliability, customer satisfaction, and safety goals.[156]

142. The Company requests, if the Commission authorizes a cap on AIP, that the cap be applied on an aggregate level, because this will enable the Company to differentiate between levels of performance through its AIP payouts without risking further under recovery of AIP expenses.[157]

143. Staff recommends capping AIP costs recovery at 15 percent, consistent with recent Commission decisions. Staff argues that an AIP amount capped at 15 percent is sufficient to attract, retain, and motivate skilled workers. Staff states the Company can continue to pay any rate it perceives to be competitive on an employee-by-employee basis.

144. UCA also recommends the Commission maintain the 15 percent cap on AIP costs, on a per-employee basis. UCA notes the Commission capped AIP at 15 percent per employee in Public Service's last gas and electric rate cases and that the Commission has applied the same principle to other utilities.[158] UCA contends other jurisdictions where Xcel Energy operates, like Minnesota, have already capped recovery of AIP expenses at 15 percent.[159]

145. We find that capping AIP at 15 percent of employee salaries is consistent with recent Commission decisions and represents a reasonable sharing of these costs between shareholders and ratepayers. Also consistent with our past decisions, we determine the cap shall be applied on an employee-by-employee basis.

g. Long-Term Incentive Program

146. Public Service seeks cost recovery of $558,259 for an Environmental Long-Term Incentive ("LTI"), based on a targeted reduction in carbon emissions, and $1,459,045 for a

[156] Hr. Ex. 108, Deselich Direct, p. 32:2-6.
[157] Hr. Ex. 129, Deselich Rebuttal, 20:1-2.
[158] Hr. Ex. 501, Fernandez Answer, p. 117:12-16.
[159] Hr. Ex. 501, Fernandez Answer, p. 117:19-20.

Time-Based LTI, matched to the length of employment with the Company.[160] Public Service contends it uses LTI as market competitive compensation to motivate and retain executive and non-executive management employees. The Company also maintains that LTI programs are widely used throughout the utility industry. For instance, the Company provides a Willis Towers Watson Study that includes more than 50 utilities, all offering LTI. The Company argues that because Colorado has set important environmental goals, disallowing the Company's request for environmental LTI would be counter to the state's clean power goals.[161]

147. Staff contends that LTI packages do not improve employee performance or benefit ratepayers and the Company has not offered evidence that LTI disallowances in Colorado in recent years has affected the Company's executive retention rate.[162]

148. UCA argues the Commission has denied the recovery of LTI expenses in past rate cases and that the Company's Environmental LTI and Time-Based LTI programs are poorly designed and duplicative. UCA contends these costs should be borne by shareholders.[163]

149. We agree with Staff and UCA that Public Service has not adequately demonstrated in this case that the Time-Based LTI leads to employee retention such that it should be included in the calculation of the base rate revenue target. We also agree that, with regard to the Environmental LTI, ratepayers should not be required to reward Company employees for achieving goals that the Company may already have a statutory obligation to achieve. We therefore reject the inclusion of these LTI-related costs in the calculation of the base rate revenue target.

[160] Hr. Ex. 108, Deselich Direct, p. 46 tbl. MPD-D-9.
[161] Hr. Ex. 129, Deselich Rebuttal, p. 27:1-10.
[162] Hr. Ex. 400, Ghebregziabher Answer, p. 93:1-6.
[163] Hr. Ex. 501, Fernandez Answer, p. 118:17-21.

h. Pension Impact of Incentive Pay

150. Public Service seeks to recover approximately $1.7 million of qualified pension expense and $110,550 of non-qualified pension expense,[164] arguing such programs like providing a 401(k) match for employees is a common practice and is a benefit to employees. The Company contends it offers a cost-effective program, which provides employees the stability of maintaining a portion of their income after retirement. The program simultaneously offers a 401(k), which allows employees to increase their overall retirement savings.[165] Although the Company argues there is no need for a cap, if the Commission determines to implement a cap, the Company requests it be applied in an aggregate rather than an employee-by-employee basis.

151. Staff notes that both base salary and incentive pay are included in the 401(k) and pension formula but that the Company has not quantified the pension impact of paying AIP above the Commission-authorized level.[166] Staff recommends, as part of the 15 percent cap on AIP, that the pension expense impact related to employee compensation for AIP above 15 percent be removed.[167] Staff further contends the Company's pension analyses on an aggregated basis instead of an employee-by-employee basis does not capture larger bonuses that have long-term impacts on the pension plan and therefore recommends that Commission require the Company to conduct these analyses on an employee-by-employee basis.

152. In Rebuttal Testimony, Public Service disagrees with Staff's position for an employee-by-employee analysis of the pension impact incentive pay. The Company instead requests, if the Commission decides to authorize a cap, then it should it be on an aggregate, not on

[164] Hr. Ex. 108, Deselich Direct, p. 61:17-19.
[165] Hr. Ex. 108, Deselich Direct, p. 65:9-14.
[166] Hr. Ex. 400, Ghebregziabher Answer, p. 97:4-9.
[167] Hr. Ex. 400, Ghebregziabher Answer, p. 98:8-11.

an employee-by-employee basis. Public Service argues that type of calculation would be simpler and less expensive, saving at least $70,000 to complete in today's dollars.[168]

153. Consistent with our previous decisions and in accordance with Staff's convincing recommendations on this point, we determine that a 15 percent cap be imposed and that it be implemented on an employee-by-employee basis.

i. Vacant Positions

154. Public Service states that including the cost for vacant positions within the COSS is necessary because the departure of an employee does not mean the position will not be refilled during the rate effective period. The Company admits it has not determined the number of vacant positions that need to be refilled. Public Service argues, however, that several factors need to be considered as some positions may be refilled or replaced at the same level, others at a different level, and some may be used to offset additional needed positions.[169]

155. Staff recommends the Commission deny recovery of all costs associated with open or unfilled positions. Staff argues that including costs associated with vacant positions which have been unfilled for more than six months in the revenue requirement, is unreasonable. Further, Staff argues the Company's lack of estimates on the cost of these vacant positions is untenable. Staff calculates there were 207 employees that left the Company involuntarily and 419 employees that accepted a voluntary retirement package across Xcel Energy in 2023.[170] Staff contends the Company must have known the savings expected with this action and should be capable of estimating the impact of vacancies, including those of the layoffs for a better measure of the revenue requirement.

[168] Hr. Ex. 130, Schrubbe Rebuttal, p. 19:7-10.
[169] Hr. Exh. 400, Att. NTG-3, p.1.
[170] Hr. Exh. 400, Ghebregziabher Answer, p. 101:13-16.

156. In its SOP, Staff argues that the Company should be capable of estimating the impact of vacancies, including those of the layoffs, and incorporate this as a known and measurable adjustment to its revenue requirement. Staff also contends it is inappropriate for ratepayers to continue to compensate the Company as if the layoffs did not occur when the Company initiated the layoffs and retirement packages to reduce the costs of payroll.[171]

157. In response, Public Service contends that it used actual labor expenses in the COSS and that the Gas O&M Labor Expenses during the 2023 Test Year are lower than in the first six months of 2024.[172] The Company further maintains that the number of vacant positions at a given time is constantly changing and such vacancies may or may not translate into lower overall labor costs.[173]

158. We agree with Staff on this issue and will disallow the costs associated with vacant positions from being included in the calculation of the base rate revenue target. We agree with Staff's reasoning that shareholders should not enjoy all of the benefits from the Company's efforts to cull its payroll in terms of earnings at the expense of ratepayers. Furthermore, it is reasonable to expect the Company to determine whether particular vacant positions should be reflected in the COSS based on expected business needs rather than to rely on a flawed blanket assumption that a previously filled position will continue to be necessary. We therefore direct Public Service to remove from the revenue requirement target calculation the full annual compensation assigned to the Company for the 207 positions opened from involuntarily terminations and the 419 positions opened from the acceptance of a voluntary retirement package in 2023.

[171] Staff SOP at p. 38.
[172] Hr. Ex. 129, Deselich Rebuttal, p. 47 tbl. MPD-R-6.
[173] Hr. Ex. 129, Deselich Rebuttal, p. 47:14-19.

j. Investor Relations Expenses and Executive Compensation

159. Senate Bill 23("SB") 291 took effect in August 2023, modifying § 40-3-114, C.R.S., by adding a new section (2) that states that a utility shall not recover certain costs from its customers, "whether as part of proposed base rate costs, a rider, or other charges…." One category of these costs prohibited from base rates is "investor-relation expenses."

160. UCA argues in this Proceeding that SB 23-291 requires all investor relations expenses to be excluded from the revenue requirement without exception. However, UCA claims that neither it nor the Commission can verify that all investor relations expenses have been removed as required by the new statute.[174]

161. Public Service rejects UCA's arguments, faulting it for concluding that SB 23-291 prohibits any expense related to raising capital without qualification. Public Service argues that the statute does not define "investor-relation expenses" and that utilities, including the Company, "unavoidably incur certain expenses to comply with applicable law, federal regulations, and contracts necessary for conducting utility business, including: costs of mandatory compliance filings such as those required by the [U.S. Securities and Exchange Commission]; the provision of disclosures to current and potential investors as required by law; and listing fees, such as those required by stock exchanges." According to the Company, such costs are unavoidable and, by definition, prudent since they are necessary for the Company to have access to capital necessary to serve customers.[175]

162. We agree with UCA that the prohibition in SB 23-291 is unambiguous, and we conclude there is no uncertainty regarding what is considered investor-relation expenses as the

[174] UCA SOP at pp. 30-31.
[175] Hr. Ex. 135, Peuquet Rebuttal, pp. 63:11-64:6.

scope of investor-relation expenses has been raised in many of the Company's previous rate cases. We therefore direct Public Service to remove from its revenue requirement calculations all investor relations expenses accounted for in the Company's 2023 test year revenue requirement calculation as investor-relation expenses.

163. Further, Public Service's arguments in its Rebuttal Testimony responding to UCA's position raise relevant questions about whether what costs the Company has tracked as investor-relation expenses fully capture the time spent by Xcel Energy officers in raising capital from investors. For instance, Public Service witness Michael Deselich's presentation of the components of the total 2023 compensation of Xcel Energy's Chairman, President, and Chief Executive Officer ("CEO") directly reveals the significance of two components of the Company's LTI which are not recovered through base rates, namely the Total Shareholder Return LTI and the Retention LTI. As Mr. Deselich points out, the absence of these components of the CEO's compensation greatly reduces the amount in the CEO total compensation line that is subject to ratepayer recovery.[176] Nevertheless, base pay and AIP-related compensation may still correspond to time spent by the CEO in raising capital and other aspects of investor relations. Accordingly, in future base rate proceedings in which Public Service seeks to adjust its base rate revenues collected from Colorado customers, the Company shall provide a full accounting of time spent by the Company's employees, including executives, in raising capital and any other aspects of investor relations. This increased transparency of employee time will better enable the Commission to verify that the exclusion of investor-relation expenses from base rates in accordance with SB 23-291 is indeed complete. Moreover, while it has long been recognized by the Commission that certain components of the LTI package should remain unrecoverable from

[176] Hr. Ex. 129, Deselich Rebuttal, pp. 42:1-43:2.

ratepayers because they directly align with the interests of shareholders, future scrutiny of the components of base rate revenue targets may further reveal that the amount of executive compensation for Xcel Energy and Public Service officers sought to be recovered in rates from Colorado customers has surpassed a just and reasonable rate for a utility charged with the public interest and is flawed in design due to financial incentives that are misaligned with the long-term interests of ratepayers (*e.g.*, the pursuit of capital expenditures to grow the Company's rate base in face of projections of significant declines in sales).

k. Organizational Dues

164. SB 23-291 also prohibits the recovery of "organizational or membership dues, or other contributions, to any organization, association, institution, corporation, or other entity that engages in lobbying or other similar activities...."[177]

165. In this Proceeding, UCA recommends the Commission exclude an additional $502,850 from the Company's revenue requirement because those amounts relate to membership dues for organizations that lobby, are actively engaged in politics, or similar activities.[178]

166. Public Service again rejects UCA's arguments, faulting UCA's interpretation of the statute. The Company argues that trade associations, industry groups, and other organizations that perform lobbying separately provide other services for utilities that benefit customers and are unrelated to lobbying, such as training, technical assistance, and research services. Public Service also claims that these organizations "explicitly segregate lobbying dues from other portions of their invoices, enabling the Company to clearly distinguish them. Public Service excluded from its cost of service the prohibited portion of organizational dues expenses that relate to lobbying."[179]

[177] § 40-3-114(2)(g), C.R.S.
[178] UCA SOP at pp. 32-33.
[179] Public Service SOP at p. 37.

167. We also agree with the UCA that SB 23-291 makes it clear that if an organization or other entity engages in lobbying, dues or fees paid by Public Service to that organization or other entity are not to be included in revenue requirements and rates. We therefore direct Public Service to remove all dues and fees paid to organizations or other entities that engage in lobbying, even if such organizations and entities also perform other services and functions.

l. Lobbying

168. SB 23-291 further prohibits base rates to recover "expenses for lobbying or other activities meant to influence the outcome of any local, state, or federal legislation, ordinance, resolution, or ballot measure."[180]

169. At the evidentiary hearing on September 10, 2024, Commissioner Megan M. Gilman asked Public Service witness Jason Peuquet whether "internal Public Service Company of Colorado or Xcel employees engaged over the past few years in working on potential legislation within Colorado."[181] Mr. Peuquet answered affirmatively, explaining that the portion of time for employees who are registered as lobbyists have spent lobbying was excluded from revenue requirements. He admitted, however, that the exclusion from the revenue requirement calculation corresponded only to the "several individuals who engage in those [lobbying] activities on a regular basis."[182] When then asked by Commissioner Gilman if employees other than the registered lobbyists similarly "track any time that relates to kind of interaction with those individuals that could relate to lobbying on the Company's behalf," Mr. Peuquet could not definitively answer the question, but he did clarify that the excluded expense as reported by the

[180] § 40-3-114(2)(e), C.R.S.
[181] Hr. Tr. September 10, 2024, p. 96.
[182] Hr. Tr. September 10, 2024, p. 96.

Company for 2023 in its annual report to the Commission filed in Proceeding No. 24M-0010EG "was just the folks who engage on this [lobbying] as a regular part of their job."[183]

170. We are therefore concerned that Public Service may not be fully complying with the requirement in SB 23-291 to exclude all lobbying costs from its base rate collections from customers. The portion of total compensation corresponding to time spent on lobbying, as that term is defined in § 40-3-114(2)(e) and (6)(g), C.R.S., for the Company's employees who are not registered lobbyists, appears to be included in the 2023 test year cost of service for the months following the enactment of the new legislation. However, Mr. Peuquet's testimony confirms for us that the record in this case contains insufficient information to support a discrete adjustment to employee compensation expenses in the test year cost of service.

171. To begin remedying this potential shortcoming in compliance with SB 23-291, we direct Public Service to take the following three actions. First, Public Service shall file an update to its 2023 annual report in Proceeding No. 24M-0010EG showing the portion of total compensation of Xcel Energy employees, by employee, that corresponds to their time spent on lobbying, as defined in § 40-3-114 (2)(e) and (6)(g), C.R.S., after the effective date of SB 23-291. Second, Public Service shall track and report the portion of total compensation for calendar year 2024 and each calendar year through the next rate case for any employees who engage in lobbying as defined by SB 23-291. Third, Public Service shall track these internal employee lobbying expenses in a regulatory account starting January 1, 2024, for review in the Company's next rate case establishing base rate revenue requirements, at which time the Commission will consider the question of whether refunds to customers are warranted.

[183] Hr. Tr. September 10, 2024, pp. 97-99.

m. Liquified Natural Gas and Compressed Natural Gas

172. Public Service includes in its annual revenue requirement approximately $6.8 million associated with expenses for the deployment of liquified natural gas ("LNG") and compressed natural gas ("CNG") as supplemental supply sources. Approximately $6.2 million of that total is associated with an LNG facility located in Breckenridge, Colorado.

173. UCA questions the inclusion of LNG costs in the 2023 test year, recommending disallowance of $5.9 million and alleging that the LNG facilities require a CPCN prior to cost recovery,[184] the Company did not explore alternatives to LNG and CNG, and affordability and safety concerns have been overlooked.[185]

174. In response, Public Service likens CNG and LNG to a peaking power plant, explaining that CNG and LNG serve specific purposes, with CNG as primary supplemental supply solution with LNG as a secondary option, to be used only if system pressures fall at or below site-specific threshold values, which depend on minimum temperatures and customer demand.[186] The Company also emphasizes that its use of LNG and CNG are part of its plans to meet emission reduction goals and avoid constructing new gas infrastructure.[187]

175. The Company further explains that cost recovery through the Company's Gas Cost Adjustment does not include upstream, transportation, security, or other site-specific costs.[188] The Company clarifies that it thus includes in its annual revenue requirement approximately $5.4 million for LNG third-party vendor support and materials and labor expense and $366,000

[184] Hr. Ex. 500, Skluzak, Answer p. 204:15-20.
[185] Hr. Ex. 500, Skluzak Answer, pp. 195:13-196:6.
[186] Hr. Ex. 127, Gilliland Rebuttal, p. 20: 7-19.
[187] Hr. Ex. 135, Peuquet Rebuttal, p. 56: 16-20; Hr. Ex. 107, Martz Direct, pp. 26:10-28:3.
[188] Hr. Ex. 135, Peuquet Rebuttal, p. 55: 9-11.

for CNG third-party vendor support and materials and labor expense.[189] The Company further argues that there is no CPCN requirement for third-party operations and maintenance expenses.[190]

176. We are unpersuaded by UCA's arguments in favor of a disallowance of LNG costs and instead conclude that Public Service has satisfied its burden to support the inclusion of third-party vendor support and materials and labor expenses of approximately $366,000 for CNG and approximately $5.4 million for LNG in the 2023 test year revenue requirement. However, we share many of UCA's concerns about the project in Breckenridge. As stated in Decision No. C24-0092, the Commission has concluded that LNG can serve as a temporary solution, potentially as a chosen non-pipeline alternative technology in place of an infrastructure project, if short-term use of such strategies is necessary.[191] Yet the record in this Proceeding raises doubts about both the temporary nature of the LNG deployed in Breckenridge and the presence of any broader non-pipeline alternative effort planned when the LNG was originally deployed in Breckenridge. The Company did not appear to have identified the capacity need much before it became a major shortfall, which potentially limited the options and increased the price of a remedy, nor did they appear to undertake preemptive actions to potentially avoid the $5.4 million per year expense for a service serving only a narrowly confined portion within the Company's system. It is our hope and expectation that such failures in planning and alternative analysis will be significantly improved through the Commission's relatively new Gas Infrastructure Planning rules, which intend to require significantly more proactive planning than was displayed in this situation.

[189] Hr. Ex. 127, Gilliland Rebuttal, p. 4.
[190] Hr. Ex. 135, Peuquet Rebuttal, p. 58:19-20.
[191] Decision No. C24-0092 at ¶ 104 issued in Proceeding No. 23M-0234G (February 23, 2024).

n. Golden Service Center Sale

177. In its Direct Testimony, Public Service initially proposed to retain 100 percent of the $4.7 million gain from the sale of land for its Golden Service Center and absorb the $400,000 loss on the sale of the Golden Service Center buildings. In its Rebuttal Testimony, however, the Company stated that it had determined that the land was solely owned by the Company's Electric Division and as such, the sale of the Golden Service Center land and buildings should be considered in an electric rate case.[192]

178. Noting the change in the Company's position, Staff recommends that the Commission ensure that the sale of the Golden Service Center buildings and land is excluded from the base rate revenue calculations in this gas proceeding.[193]

179. UCA similarly recommends the Commission hold Public Service to its Rebuttal Testimony "to shoulder the loss on the sale," but disagrees with the Company's proposition that these issues are more properly at issue in a future in electric rate case. According to UCA, the Company confirmed at the hearing that both the Electric and Gas Divisions were co-owners of the Golden Service Center buildings.[194] Therefore, UCA reasons that the loss on the sale of the Golden Service Center buildings should be decided in this Proceeding and that the Commission should find that "the record demonstrates that Public Service's Gas Division agreed to shoulder the losses on both buildings as well as gas gathering assets for a total of $0.8 million."[195]

180. In addition, both Staff[196] and UCA[197] recommend that the Commission establish, through a rulemaking, general rule regarding the treatment of non-depreciable assets.

[192] Hr. Ex. 135, Peuquet Rebuttal Rev. 1, pp. 43:20–44:3.
[193] Staff SOP at p. 44.
[194] Hr. Tr. September 10, 2024, p. 81:9-15
[195] UCA SOP at p. 39.
[196] Hr. Ex. 405, LaMere Answer, pp. 29-30.
[197] UCA SOP at p. 39.

181. Public Service contends the issues surrounding the Golden Service Center need not be addressed in this case because the land was solely owned by the Company's electric division. The Company also suggests that a rulemaking on gains and losses of non-depreciable assets would be inappropriate, citing the prior Denver district court ruling that any consideration of the payment of property taxes and O&M expenses as contributing to the value of non-depreciable property must be done "with some level of specificity as they relate (if they do) to the increase in value of the properties in question."[198] Thus, the issue would instead need to be decided on a case-by-case basis.

182. In this Proceeding, we require Public Service to exclude any amounts related to the Golden Service Center Sale in the revenue requirement calculations, consistent with the Company's statements in Rebuttal Testimony. We further decline to address the matter further in this Proceeding as suggested by UCA, due to the lack of information in this record that would support taking action here. Instead, we will fully examine the sale of the Golden Service Center in the context of the Company's next electric rate case. We also decline to open a rulemaking. If Staff and UCA seek rules that govern the treatment of gains and losses of non-depreciable assets, the filing of a petition for rulemaking would be an appropriate next step.

o. Amortization of Regulatory Assets and Trackers

(1) Prepaid Retiree Medical Assets

183. Public Service proposes to amortize its retiree medical asset over 15 years and to earn a WACC return on the balance, arguing that this approach will reduce rate base.[199] The Company further contends it is reasonable to treat the prepayments as a component of rate

[198] *Pub. Serv. Co. of Colo. v. Pub. Utils. Comm'n*, No. 20CV32793, p. 12 (Colo. Dist. Ct. Denver Cty. January 6, 2022).
[199] Hr. Ex. 117, Freitas Direct, p. 45:17-20.

base, similar to cash working capital and allowanced for deferred income taxes.[200] The Company forecasts the 13-month prepaid retiree medical asset balance to be $18,954,196 for the Company's gas operations,[201] resulting in a $1,264,473 annual prepaid retiree medical asset amortization expense as included in the Company's COSS.[202]

184. Staff recommends denying the 15-year amortization period for the Prepaid Retiree Medical Asset, arguing that Public Service has failed to show the regulatory asset relates to full ratepayer liability.[203] Additionally, Staff seeks answers to the following for future consideration: how and why this regulatory asset grew drastically since 2015; how much Public Service ratepayers have paid into the contributions made to the associated fund; and how much of the remaining balance is the responsibility of the Company's ratepayers. Staff proposes the Commission direct the Company to answer these questions in detail either in a separate filing or its next Phase I gas rate case.[204]

185. We authorize the prepaid retiree medical asset in rate base, consistent with our previous decisions. We also authorize a 15-year amortization for the determination of the target base rate revenue requirement in this Proceeding. Although Staff has failed to persuade us in this case to deny the amortization approach for eliminating the asset, we do see merit to some of the questions raised by Staff. We therefore direct the Company to provide answers to the questions raised by Staff in its next rate case establishing a base rate revenue target.

[200] Hr. Ex. 109, Schrubbe Direct, p. 71:10-12.
[201] Hr. Ex. 109, Schrubbe Direct, p. 69:3-4.
[202] Hr. Ex. 109, Schrubbe Direct, p. 73:8-12.
[203] Hr. Ex. 400, Ghebregziabher Answer, pp. 124:3-20.
[204] Hr. Ex. 400, Ghebregziabher Answer, pp. 124:1-20.

(2) Information Technology Cost Deferral

186. Public Service requests authorization to create an information technology ("IT") cost deferral for aging technology and cybersecurity capital costs. Public Service asserts that because these assets have short depreciable lives, the regulatory lag effect is much greater for these IT assets than for other assets with longer depreciable lives. For instance, Public Service estimates that 21 percent of IT investment in aging technology and cybersecurity will never be recovered from ratepayers because of such lag.[205] The Company maintains that IT is a growing part of its business, with new IT standards, evolving risks, and growing data needs. The Company further argues that IT costs are similar to other costs that have been allowed deferral, such as property tax and the damage prevention, in that the Company does not control new technology standards nor the pace of cybersecurity threats.[206] The Company further maintains that deferrals should not be reserved exclusively for extraordinary costs and that deferrals have been used for a variety of costs including capital, O&M, plant-related costs, regulatory, and employee benefit costs.[207]

187. Staff objects to the IT cost deferral on grounds that IT costs are not extraordinary costs and instead are costs under management's responsibility in the normal course of business. Staff maintains that: Public Service exercises discretion in determining its responses to cybersecurity threats and has employees with specific significant expertise in IT managing these systems; the proposed deferral would shift the risk of incurring IT costs to ratepayers, while the Company ensures full recovery of the costs; and while current deferrals afford some protection that ratepayers will not overpay, the proposed IT cost deferral would reduce the incentive for the Company to efficiently manage its IT costs.[208]

[205] Hr. Ex. 117, Freitas Direct, p. 51:2-8.
[206] Hr. Ex. 116, Peuquet Direct, pp. 44:17–45:12.
[207] Hr. Ex. 135, Peuquet Rebuttal, p. 66:4-20.
[208] Hr. Ex. 400, Ghebregziabher Answer, pp. 130:1–131:2.

188. UCA also opposes the proposed IT deferral as unnecessary and inappropriate, objecting that there is no baseline amount and rejecting the proposal that the deferral would earn WACC. UCA calculates that the Company's technology services capital additions increased by 42 percent from 2022 to 2023 and warns that this could be indicative of growth should the deferral be granted. Additionally, UCA suggests that the IT deferral would give the Company yet another incentive to build its rate base.[209]

189. We agree with the arguments put forward by Staff and UCA against the proposed IT cost deferral. The costs of IT are not extraordinary costs but instead fall under Public Service's management responsibilities under the normal course of business. IT costs reflect capital investments on which the Company earns a return and therefore the Company already has an incentive to make these investments.

(3) Pipeline Safety Integrity Adjustment ("PSIA")

190. In Proceeding No. 21A-0071G, the Commission approved a settlement agreement that terminated the PSIA rider and established a process to wind-down and transfer to base rates costs at that time recovered through the PSIA.[210] The Company had been deferring depreciation expense associated with PSIA projects placed into service in 2022 as the PSIA was being phased out.

191. In this Proceeding, Public Service proposes an 18-month amortization of PSIA deferred costs, a balance of approximately $23.2 million.

[209] Hr. Ex. 500, Skluzak Answer, p. 90:1-19.
[210] *See* Decision No. C21-0715 issued in Proceeding No. 21A-0071G (November 12, 2021).

192. Neither Staff nor UCA contest the cost recovery requested by Public Service, except that they object to the Company earning a return on the deferred balance set at the Company's WACC.

193. We authorize the inclusion of the 18-month amortization of the previously approved PSIA regulatory asset in the calculation of the base rate revenue target as an unopposed matter. We further agree with Staff and UCA that no return should apply to the deferred balance.

(4) Other Regulatory Assets

194. Public Service proposes to continue using certain previously approved trackers and to amortize account balances generally over 18 months.[211]

195. First, Public Service proposes to continue the property tax tracker with an approximate $68 million baseline going forward.[212] The Commission initially approved the property tax tracker in the Company's 2015 gas rate case, and it was last approved in the 2022 Gas Rate Case.[213]

196. Second, Public Service also proposes forward-looking baselines of approximately $2.3 million for qualified pension expenses and $130,000 for non-qualified pension expenses in accordance with the proposed test year.[214] (For comparison, the baseline established in the 2022 Gas Rate Case was $4,572,516 for both qualified and non-qualified pension expenses.)

197. Third, Public Service also seeks to implement a deferred account to track changes in Commission administrative fees charged to the Company between rate case proceedings. In the 2022 Gas Rate Case, the Commission approved the deferral of such fees with a baseline of

[211] Hr. Ex. 117, Freitas Direct, p. 87:13-14.
[212] Public Service SOP, Att. 1, at p. 4.
[213] *See* Decision No. C22-0642 issued in Proceeding No. 22AL-0046G (October 25, 2022).
[214] Public Service SOP, Att. 1, at p. 4.

$3,797,021.[215] The Company recommends setting the going-forward baseline at $3.9 million for the 2023 test year.[216]

198. Fourth, Public Service further proposes to continue tracking the costs to implement the Company's damage prevention program. This tracker was originally approved in 2015, again in the 2017 and 2020 rate cases, and most recently in the 2022 Gas Rate Case.[217] The Company requests the Commission set the baseline for damage prevention expense at $30 million.[218] This amount, the Company argues, reflects the higher costs that the Company expects in 2024.[219]

199. Finally, the Commission has previously granted approval for Public Service's deferred accounting for costs incurred related to investigation, remediation, and defense of manufactured gas plant sites. These include the Boulder manufactured gas plant site, a former manufactured gas plant site in Fort Collins, and the Denver manufactured gas plant site.[220] In this Proceeding, Public Service forecasts a regulatory liability of approximately $400,000 upon completion of the amortization approved in the 2022 Gas Rate Case.[221]

200. Staff does not directly oppose the continuation of these trackers and does not directly take issue with the proposed 18-month amortization for the purpose of setting the base rate revenue target in this Proceeding. Staff instead argues that, if the Commission approves the Company's proposed 18-month amortization period for these deferred balances, the Commission should direct the Company to eliminate the amortization expense through a GRSA as the amortized amounts are fully recovered.[222] However, Staff explicitly objects to the Company's proposal to

[215] *See* Decision No. C22-0642.
[216] Public Service SOP, Att. 1, at p. 4.
[217] Hr. Ex. 116, Peuquet Direct, p. 35:1-7.
[218] Public Service SOP, Att. 1, at p. 4.
[219] Hr. Ex. 117, Freitas Direct, p. 79:13-21.
[220] Hr. Ex. 116, Peuquet Direct, p. 41:3-6.
[221] Public Service SOP, Att. 1,at p. 4.
[222] Staff SOP at p. 39.

earn the Company's WACC on the deferred balances. Staff argues that Public Service's request to earn WACC on these deferred balances is contrary to prior Commission treatment of these deferred balances and should be denied.[223] Staff also argues that the Company's proposal to deferral certain costs already shifts the risk of incurring costs to ratepayers, while ensuring full recovery of the costs and delaying the actual impact on ratepayers. According to Staff, allowing Public Service to earn a WACC return on its tracker balances only encourages the Company to increase the amount being tracked for recovery and bring forth more deferral requests in the future.[224]

201. UCA also objects to the inclusion of the previously approved trackers and deferrals in rate base and the incumbent WACC earnings.[225] UCA notes that the Commission denied Public Service's proposal to earn a return for most of these trackers and deferrals in the 2022 Gas Rate Case.

202. We find good cause to authorize the continued use of the trackers for property taxes, qualified and non-qualified pension expenses, Commission fees, damage prevention, and qualified manufactured gas plant expenses and approve the updated baselines set forth above as well as 18-month amortizations.[226] Public Service has sufficiently shown the benefits of these trackers and deferred accounts and we agree with the Company that an 18-month amortization is the proper input to the calculation of the base rate revenue target in this Proceeding. We also deny the Company's request to earn a return at WACC on the deferred amounts. We find no reason to deviate from our previous conclusions regarding some of these same accounts in the 2022 Gas Rate Case and agree with Staff and UCA that a WACC return is not appropriate for any of these tracker accounts going forward.

[223] Hr. Ex. 400, Ghebregziabher Answer Rev. 1, pp. 125-126.
[224] Staff SOP at pp. 39-40.
[225] UCA SOP at p. 36.
[226] Public Service SOP, Att. 1, at p. 4.

(5) Post-Amortization Adjustments to Base Rates

203. As stated above, Staff asks the Commission to direct the Company to eliminate the amortization expense through a modified GRSA (*i.e.*, a negative or reduced GRSA) the Company's proposed 18-month amortization period for the deferred balances is approved.[227] According to Staff, this approach will ensure that the Company does not "over-recover on these deferred balances."[228]

204. We decline to adopt the reduced or "negative GRSA" as proposed by Staff. The use of a negative GRSA to reflect the end of the aforementioned amortizations is inconsistent with the normal operation of base rate cost recovery[229] and further suggests a level of precision in utility cost accounting and ratemaking that cannot be achieved, particularly over time.

p. Retiree Medical Contributions

205. In its Direct Testimony, Public Service explains that the Company can work toward eliminating the prepaid retiree medical asset from rate base by scaling back contributions that would otherwise increase the size of the asset. Public Service proposes, consistent with the Commission's direction to the Company to find ways to help ensure the asset is retired sooner rather than later, to forego making contributions in 2023 and the foreseeable future.[230]

206. We grant the Company's request to discontinue contributions to the retiree medical plan as an uncontested matter.[231]

[227] Hr. Ex. 400, Ghebregziabher Answer Rev. 1, p. 115:11-16.
[228] Staff SOP at p. 39.
[229] Hr. Ex. 136, Freitas Rebuttal, pp. 14-15.
[230] Hr. Ex. 109, Schrubbe Direct, pp. 72-73.
[231] Public Service SOP, Att. 1, at p. 5.

q. Rate Case Expenses

207. Public Service requests recovery of about $1.6 million for rate case expenses incurred for this Proceeding. Approximately $1.2 million of that total corresponds to outside legal services, while approximately $260,000 ties to the use of two outside consultants (*i.e.*, Public Services witnesses Bulkley and Amen).

208. Public Service states that it issued a competitive solicitation to obtain the legal services used for this case and retained the law firms of Taft Stettinius & Hollister LLP and Wilkinson Barker Knauer LLP, and that its internal attorneys manage outside legal resources and provide additional legal services.[232] The Company states its internal legal department handles all regulatory matters and is unavailable to take on the complex requirements of a rate case proceeding in addition to its other work. Public Service also offers that the expertise brought by outside legal counsel contributes to efficiencies in the rate case process through development of a comprehensive factual record.[233]

209. Public Service further contends that its outside witnesses bring an independent view in their respective specialties. The Company states it does not use an internal employee for ROE testimony due to the specialized nature of the field. The Company likewise suggests the expertise of the outside witness that addressed the Company's Revenue Stability Mechanism proposal: "can help shed fresh light on the public policy benefits of decoupling in general, the various approaches to consider, how some other jurisdictions have opted for those various approaches over other, and how a specific design could work for the Company's gas business."[234]

[232] Hr. Ex. 116, Peuquet Direct, pp. 64:5–65:19.
[233] Hr. Ex. 116, Peuquet Direct, pp. 66:5-17.
[234] Hr. Ex. 116, Peuquet Direct, pp. 68:8–69:2.

210. According to the Company, Staff and UCA both support the Company's proposed amortization period of 36 months of this regulatory asset, with no return, as well as the Company's proposal to recover the unamortized portion of rate case expenses from the Company's 2022 Gas Rate Case.[235]

211. Staff notes that although the requested rate case expenses for this Proceeding are less than the $2.2 million requested for the 2022 Gas Rate Case, that case combined a review of overall annual revenue requirements (*i.e.*, "Phase I rate case") with a review of class cost allocation and rate design (*i.e.*, a Phase II rate case").[236] Staff contends the Company did not provide sufficient evidence in this case of cost savings through contracting outside resources rather than using internal legal staff and subject matter experts and notes that in the last rate case the Commission capped recovery at actual incurred expenses of $2 million and encouraged the Company to better manage its expenses.[237] For this Proceeding, Staff recommends a cap on recoverable rate case expenses of $1.3 million.

212. UCA recommends disallowance of the costs of the Company's outside consultant and to limit to 50 percent the outside legal fees.[238] UCA takes issue with the Company's statement that it issued a competitive solicitation to secure the legal services and contends the Company provides no evidence that its outside legal counsel and consultants provide more efficient and cost-effective services than those already available with in-house staff.[239]

213. As we approach this issue, we are mindful, on the one hand, that the Commission has long allowed regulated utilities to recover as a proper operating expense attorneys' fees

[235] Hr. Ex. 135, Peuquet Rebuttal, p. 81:15-17.
[236] Hr. Ex. 406, Marcella Answer, p. 9:2-5.
[237] Hr. Ex. 406, Marcella Answer, p. 13:7-11.
[238] Hr. Ex. 500, Skluzak Answer, p. 176:11-14.
[239] Hr. Ex. 500, Skluzak Answer, p. 163:3-17.

incurred in litigating rate case before the Commission. We have recognized such expenses are a legitimate cost of providing utility service, necessitated by Commission regulation of the utility and that utilities are required to file tariffs to initiate a rate case. On the other hand, we now have direction from the legislature to examine these expenses with more scrutiny. As enacted by SB 23-291, § 40-3-102.5(1), C.R.S., requires the Commission to establish rules to limit the amount of rate case expenses that a utility may recover from ratepayers. Two options for the rules the Commission must consider are: (1) limiting the amount of expenses for outside experts, consultants, and legal resources that are recoverable; and (2) setting an overall percentage of the utility's expenses in a rate case that are not recoverable. The rulemaking is ongoing before an administrative law judge in Proceeding No. 24R-0168EG.

214. Although, as Public Service points out in its SOP, the rules contemplated by SB 23-291 are not yet final, the intent of the legislation is clear. Furthermore, the record in this Proceeding does not reflect that the Company moderated its rate case expenses in response to the Commission's directives in past rate cases nor in response to SB 23-291.

215. Therefore, in consideration of the record specific to this case, we authorize Public Service to recover an amount not to exceed the total estimated costs put forward in the Company's Rebuttal Testimony of approximately $1.6 million,[240] less $130,000, an amount equal to one-half of the $260,000 incurred for the two outside consultants used by the Company in this rate case. The benefits that inure to ratepayers from a utility rate increase are at least matched, if not substantially exceeded, by the benefits enjoyed by shareholders; hence we find it appropriate for shareholders to carry an equal proportion of the cost of those consultants' services for which they too receive a benefit.

[240] Hr. Ex. 135, Peuquet Rebuttal, p. 80:8.

r. Conclusion

216. The aforementioned findings, conclusions, and adjustments to Public Service's calculation of its annual base rate revenue requirement culminate in a just and reasonable basis for an authorized overall increase in the Company's base rate revenue collections.

217. For clarity, all requests raised by intervening parties through written testimony or SOPs directed at the calculation of the test year revenue requirement but not addressed by this Decision are denied.

218. We further find good cause to permanently suspend the effective date of the base rate tariff sheets filed under Advice Letter No. 1029-Gas.

219. We also grant, as an uncontested matter, Public Service's proposal to implement the authorized increase in base rate revenues through a modified GRSA.[241] Service and Facility Charge revenue will be excluded from the GRSA, and be only applied to the volumetric charge revenue, if applicable.

220. Public Service shall put into effect a modified GRSA calculated in the manner the Company presents in its Direct Testimony through a compliance tariff filing made on not less than two business days' notice for effect on November 5, 2024, the end of the suspension period established by Decision Nos. C24-0129 and C24-0235-I. The modified GRSA shall be calculated to collect the annual base rate revenue requirement established by the findings, conclusions, and adjustments to Public Service's COSS for the 2023 test year as set forth in this Decision.

3. Revenue Deferral Surcharge

221. While the purpose of Public Service's Advice Letter No. 1029-Gas filing is to increase base rate revenues, the Company puts forward a proposal to delay the rate increase

[241] Hr. Ex. 101, Berman Direct, pp. 55-56.

resulting from this Proceeding for bill stability. Specifically, Public Service proposes deferring the implementation of the increased GRSA until February 15, 2025, when the Extraordinary Gas Cost Recovery Rider terminates pursuant to the Commission's decisions in the Company's Winter Storm Uri Proceeding. Without this rate implementation proposal, Public Service states that its gas customers would experience increasing bills during the peak of the upcoming hearing season and then experience a significant bill reduction shortly thereafter.

222. Notably, as part of this proposed delay in implementing the rate increase, Public Service proposes a Revenue Deferral Surcharge to be applied to customer bills from February 15, 2025 through February 16, 2026 in order to account for revenues not collecting between November 2024 and next February 15.[242] The Revenue Deferral Surcharge would be calculated for each rate class by multiplying the GRSA approved in this proceeding by the monthly billing determinants from the November 2024 through February 2025 deferral period, then subtracting the actual base rate revenues collected from each rate class during the deferral period.

223. In addition, Public Service seeks to apply the WACC to the amount deferred for collections through the proposed Revenue Deferral Surcharge. The Company contends that earning its WACC on the deferral is appropriate because doing so acknowledges that if rates were implemented in November 2024 the Company would be recovering costs that have already occurred.[243]

224. The resulting Revenue Deferral Surcharge revenue requirement for each rate class would be divided by the forecasted base rate revenue for the recovery period, and a true-up would be conducted with any adjustments applied to the Company's Gas Cost Adjustment beginning in

[242] Hr. Ex. 101, Berman Direct, pp. 59:10–60:4.
[243] Hr. Ex. 101, Berman Direct, p. 61:3-13.

April 2026.[244] Public Service calculates that some $73.8 million would be deferred from November 1, 2024, through February 14, 2025.

225. Staff objects to the Revenue Deferral Surcharge for at least three reasons. First, Staff argues the deferral will create inter-temporal inequities by potentially undercharging customers during the deferral period with the undercharged recovery becoming the responsibility of customers during the surcharge period. According to Staff, the two sets of customers might not overlap leading to a benefit for some customers at the cost of other customers. Second, customers might not benefit from the deferred cost recovery because gas commodity prices could be low during the deferral period and high during the full 12-month recovery period. Third, Staff notes the Revenue Deferral Surcharge will increase bills in the summer when electricity bills are the highest, adding to the energy burden of some ratepayers. Staff also suggests the Revenue Deferral Surcharge could cause customer confusion, adding unnecessary complexity to the process of tracking revenue, introduction potential for errors, and making regulatory oversight more difficult.[245]

226. Staff specifically objects to Public Service's proposal to earn WACC on the deferred revenues, pointing out the Company filed this rate case with full knowledge that a rate increase would be implemented at the beginning of the 2024-2025 hearing season. Staff further notes that similar deferrals used in the past did not attach a return to the balance. Staff also argues that Public Service is not financing its entire revenue requirement with this deferral and further posits that a WACC return is not appropriate for expenses and other non-capital related costs.[246]

[244] Hr. Ex. 116, Att. JJP-3, pp. 5-7.
[245] Hr. Ex. 401, O'Neill Answer, p. 39:1-14.
[246] Hr. Ex. 401, O'Neill Answer, p. 40:7-12.

227. UCA also objects to the Revenue Deferral Surcharge, contending that the proposal is complicated and convoluted. UCA also notes that the WACC earnings on the estimated $73.8 million balance would be some $3.3 million.[247] Additionally, UCA is concerned that the Revenue Deferral Surcharge period from February 15, 2025 to February 15, 2026, subjecting ratepayers to the surcharge for parts of two winter heating seasons.[248]

228. We agree with the objections raised by Staff and UCA and decline to approve the proposed deferral of the rate increase authorized by this Decision. We are particularly persuaded that customers might not benefit from the deferred cost recovery due to unknown gas commodity prices in the future. Likewise, the deferral is complex and could cause customer confusion.

229. As pointed out by both Staff and UCA, Public Service could have delayed the filing of Advice Letter No. 1029-Gas by only a few months to achieve the delayed implementation of a base rate increase. That delay could also have been supported by a more tempered pace of capital expenditures following the enactment of the new Colorado energy policies from the 2021 session by the General Assembly, since those statutes were enacted well before the test year adopted in this Proceeding.

230. Consistent with the discussion above, we direct Public Service to put a modified GRSA into effect on November 5, 2024.

4. Additional Contested Matters

a. Revenue Stabilization Mechanism

231. The tariff sheets filed with Advice Letter No. 1029-Gas include Sheets 52 through 52B to implement a proposed Revenue Stability Mechanism adjustment, a form of decoupling

[247] Hr. Ex. 500, Skluzak Answer, p. 211:5-6.
[248] Hr. Ex. 500, Skluzak Answer, p. 214:1-17.

intended to address potential financial disincentive associated with conservation and other activities that decrease sales. The proposed Revenue Stability Mechanism is a "full decoupling" mechanism because it completely disconnects the Company's margin revenue[249] from sales volumes, without weather normalization. Public Service argues that full decoupling allows the Company guaranteed revenues independent of sales and allows the Company to cover fixed costs and maintain financial stability.[250]

232. Anticipating that intervening parties might object to full decoupling, Public Service argues against the adoption of "partial decoupling" that accounts for variances in weather and potentially other factors that affect sales. The Company argues that partial decoupling puts the Company's opportunity to recover and earn a reasonable return on fixed costs at risk and contributes to rate instability.[251] Public Service provides a discussion of revenue decoupling mechanisms across the United States, concluding that New York and Massachusetts have similar climate goals to Colorado and have implemented full revenue decoupling.[252] Public Service also contends that full decoupling is easier to administer than other forms of decoupling because it avoids discussions as to how to calculate and apply weather normalization. Public Service further attempts to bolster support for the Revenue Stability Mechanism by explaining that if it had been in place during the 2022-2023 heating season, customers would have seen a subsequent rate decrease. [253]

233. Staff objects to the proposed Revenue Stability Mechanism for two principal reasons. First, Staff suggests review of the proposal should be accomplished in a combined revenue

[249] Margin revenues are calculated as the cost of service without purchased gas expenses and other "flow-through" items such as revenue taxes.
[250] Hr. Ex. 115, Amen Direct, pp. 13:21–14:9.
[251] Hr. Ex. 135, Peuquet Rebuttal, pp. 36:16–38:3.
[252] Hr. Ex. 115, Amen Direct, p. 19:3-11.
[253] Hr. Ex. 135, Peuquet Rebuttal, p. 34:16-18.

requirement (*i.e.*, "Phase I rate case") and class cost allocation and rate design proceeding (*i.e.*, a "Phase II rate case") or at least a Phase II rate case instead of the instant Phase I proceeding. Second, Staff argues the Revenue Stability Mechanism will inappropriately relieve Public Service of all risk of under-recovery, including weather-related risk, noting that with climate change, the risk of weather-related under-recovery is greater than the risk of over-recovery.[254] Accordingly, if the Commission approves the Revenue Stability Mechanism, Staff recommends the Commission modify it to become a partial decoupling mechanism that excludes revenue adjustments resulting from variations in weather. Staff further suggests, if the Revenue Stability Mechanism is approved, the Commission should require the Company to eliminate the Demand-Side Management Acknowledgement of Lost Revenues ("DSM-ALR") from Public Service's demand-side management cost adjustment tariff sheets instead of adjusting the Revenue Stability Mechanism to account for DSM-ALR revenues as the Company proposes.

234. Staff further argues that any approved decoupling mechanism should have the narrow purpose of removing the Company's disincentive to fully implement demand side management and beneficial electrification. Staff contends the plain language reading of § 40-3.2-105(3)(b), C.R.S., is that this statutory provision does not apply to the proposed Revenue Stability Mechanism because the statute refers to a revenue per customer mechanism, while the Revenue Stability Mechanism is instead a measure that addresses total revenues collected.[255] Staff further points to the Commission's decision in the 2022 Gas Rate Case in which the Commission stated "the statute is focused on implementing a decoupling mechanism aimed at DSM implementation, not 'full' decoupling." Staff agrees with Public Service that the outcome in

[254] Hr. Ex. 403, Haglund Answer, p. 19:2-16.
[255] Hr. Ex. 403, Haglund Answer, p. 9:4-10.

that case was the Company elected to maintain the DSM-ALR and withdrew its decoupling request.[256]

235. UCA characterizes the Revenue Stability Mechanism as an attempt by the Company to eliminate gas usage risk by locking in total revenues. Additionally, UCA argues this proposal would permit Public Service to recover all revenues notwithstanding that climate change decreases gas sales.[257] UCA also suggests that, if the Commission authorizes a decoupling mechanism, that decision should be linked to the Commission's decision setting the Company's ROE. Additionally, UCA recommends, if the Commission wishes to allow a decoupling mechanism, then a separate proceeding should be opened so that the public interest issues in a decoupling mechanism can be appropriately addressed.[258]

236. We decline to approve the proposed Revenue Stability Mechanism. First, the Company's own testimony supports our conclusion that the primary issue the mechanism is attempting to resolve is one of rate design, and this is not a rate design proceeding.[259] Public Service's currently-effective base rates for residential and small commercial customers will be adjusted by the GRSA established in this Proceeding, where such rates recover the Company's fixed costs through volumetric charges, whereas no changes to the current rate design are being proposed. We further agree with UCA's observation that it is necessary to consider how decoupling alters the Company's risk profile and hence the appropriate ROE to be established by the Commission. For these reasons, we conclude that Commission review of the Revenue Stability Mechanism or any other decoupling mechanism requires the full context of a combined Phase I and Phase II rate case.

[256] Hr. Ex. 403, Haglund Answer, p. 10:3-17.
[257] Hr. Ex. 500, Skluzak Answer, pp. 220:10–221:3.
[258] Hr. Ex. 500, Skluzak Answer, pp. 222:16-223:3.
[259] Hr. Ex. 115, Amen Direct, p. 11:8-11; Hr. Tr. September 10, 2024, p. 204:23-205:8.

b. Gas Storage Inventory Cost

237. Public Service filed three tariff sheets under Advice Letter No. 1029-Gas that are a portion of the sheets that implement the Company's Gas Cost Adjustment, *i.e.*, Sheet Nos. 50A through 50C. By filing these sheets, Public Service seeks to revisit the final decision from the 2022 Gas Rate Case addressing gas storage inventory costs ("GSIC"), in which the Commission modified the carrying cost on gas inventories held in storage from the Company's WACC to a measure of short-term debt.[260] In that case, the Commission agreed with Staff's principal argument that the return on gas storage inventories should not be set at the Company's WACC because of their temporary and volatile nature and because the Commission had already started engaging in the practice of applying returns other than the general WACC to certain accounts and balances.

238. In this Proceeding, Public Service suggests that a present policy emphasis on service reliability and rate stability supports authorizing a WACC return on gas held in storage, because storage helps reduce fuel cost volatility. The Company asserts that the WACC better reflects the cost of financing gas inventories and any lower return on gas storage inventories creates a financial disincentive to fully developing and relying on those assets.[261] Public Service further contends the GSIC is not short-term because natural gas storage is used to provide gas service over the long term. The Company also asserts it is the amount of inventory that is required at a specific period of time that is important for the Commission to consider, not the amount of time that fuel deliveries are present or held in reserve storage.[262] For instance, the Company posits that just like a natural gas pipeline, which is considered an asset that earns a WACC return regardless of its

[260] Decision No. C22-0642 at ¶ 381 issued in Proceeding No. 22AL-0046G (October 25, 2022).
[261] Hr. Ex. 116, Peuquet Direct, pp. 48:19-49:19.
[262] Hr. Ex. 135, Peuquet Rebuttal, p. 74:3-9.

capacity at any given time, gas held in inventory is used and useful and should earn a WACC return because it provides long-term reliable service.[263]

239. Staff disputes this reasoning and urges that the Commission should reject the Company's (repeated) request. Echoing the arguments it made in the earlier rate case, Staff contends that application of WACC to gas storage inventories is inconsistent with recent Commission decisions, does not reflect the short-term and volatile nature of GSIC, disregards financial principles, and unnecessarily increases costs to ratepayers. Notably, Staff maintains there have been no policy or other changes since the 2022 Gas Rate Case that warrant reconsideration of the issue, particularly so soon.

240. UCA likewise argues that nothing has changed since the 2022 Gas Rate Case and there is no reason for the Commission to alter its decision on the return for GSIC.[264] UCA further questions the Company's statement that a return of less than WACC could influence its decision to use gas storage, noting that the difference between WACC and short-term debt return for GSIC is only approximately $383,000.[265]

241. We decline to take up this issue again in this Proceeding. The appropriate GSIC was fully examined in the 2022 Gas Rate Case, and we agree with UCA and Staff that nothing has changed since that time to warrant reconsideration of the Commission requiring the GSIC to be set at a short-term debt rate. Therefore, Public Service shall not modify Sheet No. 50C.

c. Gas Quality of Service Plan

242. Public Service's current gas quality of service plan ("QSP") and corresponding metrics were addressed by the Commission in the 2022 Gas Rate Case. Specifically, the

[263] Hr. Ex. 135, Peuquet Rebuttal, pp. 74:10-75:2.
[264] Hr. Ex. 500, Skluzak Answer, p. 243:3-8.
[265] Hr. Ex. 500, Skluzak Answer, pp. 224:11-13, 235:15-20.

Commission approved continuation of the existing QSP measures with the same penalty levels through December 31, 2024.[266]

243. Public Service files an annual report on the previous year's performance. If Public Service fails to meet each QSP performance baseline, each year the QSP is in effect, it incurs a financial penalty. Financial penalties can be imposed for failing to meet these metrics, at $250,000 per metric with a total maximum penalty of $750,000 per single performance year. This accrues in a regulatory liability to be credited to customers in the next Phase I gas rate case.

244. Public Service seeks Commission approval in this Proceeding to further extend the current QSP through December 31, 2026.[267] The Company argues that the current QSP metrics are appropriately focused on the objective of delivering quality gas service to customers while aligning with the Commission's mission to ensure safety, reliability, and adequate gas service. The Company requests that no changes be made to the existing QSP metrics or thresholds at this time, explaining that the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") is currently conducting a rulemaking regarding leak detection, repair, maintenance, and reporting. Additionally, the Commission is also undertaking relevant rulemaking on leak detection reporting.[268] According to Public Service, these rulemakings and the implementation of the Company's Clean Heat Plan and Gas Infrastructure Plan mean that changes to the QSP metrics at this time would be premature.

245. The Company further notes that the Commission has also contemplated a more comprehensive review of the QSP for the Company's gas operations, stated in 2022 Gas Rate Case decisions, that new and revised metrics will likely be adopted in the furtherance of greenhouse gas

266 *See* Decision No. C22-0642 at ¶ 315.
267 Hr. Ex. 104, Gilliland Direct, p. 59.
268 *See* Proceeding No. 22R-0491GPS.

emission reductions and new gas planning procedures, even while performance measures related to safety and service quality will also remain important. The Commission seeks a more complete redevelopment of the QSP to align gas utility expenditures with the priorities of these various efforts.[269]

246. Staff agrees with the Company's request to extend the existing QSP through December 31, 2026, but recommends Commission order the Company to implement certain modifications to the performance goals in this Proceeding.

247. For instance, Staff asks the Commission to direct the Company to work with Staff and other interested parties to revitalize and upgrade the terms and conditions of the gas QSP so that it better aligns with the Company's electric QSP. Staff further recommends the Commission require Public Service to file the updated gas QSP terms and conditions with the Commission on June 1, 2025, to be implemented for a one-year credit payout-free trial period from January 1, 2026, through December 31, 2026.[270] Similarly, Staff recommends that the Commission order the Company to modernize the gas QSP to ensure compliance with the requirements of SB 21-272 and the additional guidance to better consider impacts on disproportionately impacted communities. Staff argues, for example, that the gas QSP annual reports do not provide granular data to sufficiently analyze whether certain areas within the Company's territory receive different levels of service. Further, Staff contends an extension of the current gas QSP in its existing form could delay a comprehensive incorporation of equity considerations until 2026.[271]

248. Staff also suggests that the Commission require updates to certain metric baselines. First, Staff proposes modifications to the damage prevention metric, decreasing the standard from

[269] Decision No. C22-0642 at ¶ 314.
[270] Hr. Ex. 404, Ramos Answer, p. 67:5-13.
[271] Staff SOP at p. 30.

1.47 damages per 1,000 locates to 1.3 damages per 1,000 locates because, according to Staff, the Company has demonstrated continued improvement in this metric.[272] Second, Staff seeks to reduce the standard for Grade 2 leak repair time from 52 days to 28 days. According to Staff, PHMSA has modified its requirements for non-hazardous leak repair to 30 days, and in 2023 Public Service realized an average repair time of 25.9 days, so the 28-day threshold is appropriate.[273]

249. Staff also proposes the Commission direct the Company to bring its next gas QSP in a standalone proceeding. According to Staff, a separate case would give the Company, stakeholders, and the Commission additional time to consider robust improvements to the plan.[274]

250. In its Rebuttal Testimony, Public Service disagrees with Staff's recommended QSP modifications and requests the Commission reject them. Specifically, for the damage prevention metric, the Company contends that while its performance has been consistent over the past few years, it is premature to modify the metric to 1.30 per 1,000 locates because the volume of locates has been increasing each year and the trend is expected to continue. Public Service states that, additionally, it cannot control the number of requests and external factors including the number of projects involving excavating by non-Public Service entities. The Company also rebuts Staff's proposed changes to the Grade 2 leak repair metric, arguing that a more appropriate metric would be 40 days, based on its three-year average of 44 days. The Company contends that while its 2023 repair time was the best the Company achieved in more than a decade, setting a metric based on 2023 performance is not appropriate because average repair times fluctuate year to year. The Company also points out that there is no 30-day repair timeframe for Grade 2 leaks proposed in the PHMSA rulemaking and there also is no definition of a non-hazardous leak.

[272] Hr. Ex. 404, Ramos Answer, p. 53:4-9.
[273] Hr. Ex. 404, Ramos Answer, p. 50:6-13.
[274] Staff SOP at p. 31.

251. Despite these objections, Public Service nevertheless agrees to meet with Staff and any other stakeholders prior to the filing of its next gas QSP to discuss metrics and associated information.

252. We authorize the continuation of Public Service's existing QSP measures with the same penalty levels through December 31, 2026. While we appreciate Staff's efforts in seeking improvements to the QSP, we find the Company's responses objecting to Staff's proposals compelling, particularly with regard to timing the proposed changes in the immediate wake of this Proceeding. Consistent with the Commission's previous findings and directives, we require Public Service to make a future filing sufficiently before the expiration of the authorized extension for the purpose of undertaking a more comprehensive review of the QSP for the Company's gas operations to consider such modifications to existing measures as advanced by Staff in this Proceeding and to consider new metrics related to greenhouse gas emission reductions and gas planning procedures. We agree with Staff that such a review would be best accomplished in a stand-alone proceeding filed well before the new expiration of the existing QSP on December 31, 2026.

d. City of Boulder Franchise Agreement

253. Although Staff acknowledges that there are no costs in Public Service's proposed revenue requirement associated with the Company's franchise agreement with the City of Boulder, Staff suggests the Commission should direct the Company take proactive measures to identify Boulder-related costs in future rate case proceedings.

254. In response, Public Service states any costs associated with the Boulder Franchise Agreement will be included in its cost of service, as is its general practice as a regulated utility.

255. We decline to issue any directive to Public Service regarding the Boulder Franchise Agreement based on the record in this Proceeding.

e. Capitalized Labor Costs

256. Public Service argues that fundamental accounting and ratemaking practice allows a utility to include labor costs incurred when constructing a capital project to become part of the plant investment costs included in rate base. The practice hence results in labor costs being capitalized as plant in-service.

257. Staff argues the lack of transparency on how much capitalized labor Public Service includes in rate base is a concern. Staff asks that the Commission direct the Company to track labor-costs that are being capitalized and recovered through rate base. Staff argues, even though capitalized labor can be included as plant in-service when labor costs are incurred during the construction of a capital project, the Company failed to provide information related to such labor costs. Staff specifically recommends the Commission require Public Service to track how much its capital costs derive from labor costs and how much of its overall labor related costs are being capitalized.[275]

258. In Rebuttal Testimony, Public Service contends that tracking capitalized labor costs as suggested by Staff is unnecessary and impractical. For instance, Public Service explains it determines whether labor should be capitalized based on policies establishing what work and projects meet capitalization requirements, as well as what individual activities are directly associated with the construction of the asset and therefore can be capitalized.[276] Because the decision to capitalize labor is based on each project and the type of work, there is not an overall

[275] Staff SOP at p. 39.
[276] Hr. Ex. 133, Moeller Rebuttal, pp. 44-45.

budget for "capitalized labor." The Company further disagrees with Staff's suggestion that there could be a lack of transparency between labor costs tracked as O&M expenses and capitalized labor. Public Service contends the Commission's focus should not be how much of rate base is capitalized labor, rather if the costs of projects are prudent and if the Company has appropriate policies for capitalizing these costs.

259. We agree with Staff that more information about capitalized labor costs should be provided by Public Service in a rate proceeding such as this case. We find merit in the review of capitalized labor costs and the comparison of such amounts to labor costs expenses as O&M costs.

260. We therefore require the Company to include a presentation of details such as the total dollars capitalized, by job category, and the earnings on these amounts. We require the Company to present in its future rate case filings the capitalized labor costs associated with individual projects newly entering the Company's rate base with sufficient detail both to organize and aggregate the information by project category and to show compliance with the Company's own capitalization policies.

5. Future Advice Letter Filing

a. Staff Recommendation for Phase II Filing Requirement

261. Staff recommends the Commission require Public Service to file an advice letter to initiate a base rate class cost allocation and rate design proceeding (*i.e.*, a "Phase II rate case") within six months of a final decision in this Proceeding. Staff suggests that this sequenced filing schedule of rate cases will ensure a timely review of yet unresolved issues. As an example, Staff notes that Public Service plans to address remaining interruptible service issues from the Winter Storm Uri Proceeding in its next Phase II filing. Staff calculates that if, as the Company states, the

Phase II rate case is not filed until the end of 2025, the issues raised in the new case, including those surrounding interruptible services, would not be fully resolved until well into 2026.[277]

262. Public Service explains in response that its next Phase II filing will also be influenced by certain other proceedings, such as the forthcoming depreciation study as discussed above as well as the Company's next Gas Infrastructure Plan, due to be filed in 2025. The Company argues that those factors should be weighed along with the Commission's interest to fully resolve the interruptible service issue. Public Service further contends that it is not practicably possible to implement the requirements of a Phase I rate case decision within six months.[278]

b. Line Extension Policy and Recovery of Capacity Expansion Costs

263. In Direct Testimony, Public Service witness Ray Gardner summarizes the $1 billion of additional capital investments made to the Company's gas system since the 2021 test year used in the 2022 Gas Rate Case. The total is broken down into four categories: $238.1 million is for New Business; $127.6 million is for Capacity Expansion; $567.1 million is for System Safety and Integrity; and $69.5 million is for Mandatory Relocations.[279]

264. According to Public Service, the new business capital category includes utility investment needed to provide gas service to new customers, or to customers requiring new gas service. The Company states the majority of new business work consists of smaller or routine projects, such as installation of a new service or short new main extension. New business projects are driven by customers and outside entities such as developers.[280] Public Service further explains

[277] Staff SOP at pp. 40-41.
[278] Public Service SOP at p. 45.
[279] Hr. Ex. 105, Gardner Direct, p. 13.
[280] Hr. Ex. 105, Gardner Direct, p. 45.

that the customer funds a portion of the project, which amount is determined by the terms of the line extension policy in effect at the time of the new business request. However, under current practice, infrastructure that serves broader customer areas or overall system needs, like regulator stations, are solely the cost responsibility of the Company.[281] Public Service further states that of the $238.1 million of New Business projects in the test year rate base additions, only $34.5 million correspond to "discrete" projects, whereas most of the costs correspond to "routine" projects.[282] Furthermore, only two of the discrete projects had total costs greater than $3 million: Canyons Development and Coal Creek Canyon Pines.[283]

265. The Canyons Development is a new development located east of Castle Pines, Colorado, with approximately 1,500 multi-family homes, 2.1 million square feet of commercial space, 250 townhome units, and a fitness center. The project included installation of approximately 1.1 miles of 6" HP pipeline, to which the customer contribution would apply, and installation of a new high pressure-to-pounds medium regulator station F-976. The Company incurred approximately $5.1 million in capital additions. Of this amount, the customer contributed approximately $2.3 million to the HP portion, or just over 50 percent of the total cost of the HP portion, which was approximately $4.5 million in capital additions.[284]

266. Public Service describes the Coal Creek Canyon Pines project to be the build out for a residential development located between Boulder and Arvada, Colorado, for 90 new custom single-family homes. The project required some 3,000 feet of main reinforcement, installation of 23,465 feet of medium density polyethylene main to service future residential lots, and connection of a new regulator station to reduce pressure. Public Service states it incurred approximately

[281] Hr. Ex. 105, Gardner Direct, p. 46.
[282] Hr. Ex. 105, Gardner Direct, p. 47.
[283] Hr. Ex. 105, Gardner Direct, p. 48.
[284] Hr. Ex. 105, Gardner Direct, p. 49-52.

$4.3 million in capital additions to complete the project. Public Service indicates this amount is net of the approximately $1 million of customer contribution for certain pipeline portions.[285]

267. Public Service further explains that capacity expansion projects include both individual projects and sets of inter-related facilities needed to maintain system reliability and meet a specified capacity expansion need, including for new customers or facilities that are not otherwise new business projects, or for reliability and growth related to existing customers.[286] Of the total $127.6 million of total additions since the test year in the 2022 Gas Rate Case, approximately $89.1 million corresponds to discrete projects and $38.5 million corresponds to "routines."[287] The Company highlights six discrete projects, including the Questar Supply Project discussed above ($19.9 million), the West Metro project addressed in Proceeding No. 21A-0472G ($16.5 million), the Rampart Range Reinforcement ($14.4 million), the Winter Park Tie ($8.0 million), the Del Norte Compressor Stations ($11.7 million), and a reinforcement project in Parker, Colorado ($3.4 million).[288]

268. Upon reviewing this information, the related Supplemental Direct Testimony required by Decision No. C24-0240-I, and the balance of the record in this Proceeding, we repeat our considerable concern over both the Company's inherent financial incentive to spend capital in order to build its rate base and the potential that unseen subsidies for new growth are often built into the formulation of base rates upon implementation of its line extension policies or cost allocation for new and upgraded facilities, more generally, which may not currently appear in any specific policy. These concerns are exemplified by the Coal Creek Canyon Project, where record evidence clearly shows that the revenues from the new customers associated with that specific

[285] Hr. Ex. 105, Gardner Direct, pp. 52-56.
[286] Hr. Ex. 105, Gardner Direct, p. 65.
[287] Hr. Ex. 105, Gardner Direct, pp. 52-56.
[288] Hr. Ex. 105, Gardner Direct, pp. 66-67.

development did not come close to offsetting the costs incurred by the system to serve that new demand.[289] These concerns about existing customers subsidizing new growth were generally validated and amplified by the legislature when it enacted SB 23-291, which requires: "A gas utility shall not provide an applicant an incentive, including a line extension allowance, to establish gas service to a property."[290] During questioning at the evidentiary hearing, Company witness Steven Berman indicated the Company anticipates that their interpretation of SB 23-291 would only lead to modest reductions in the capital expenses which would be added to rate base, earning the Company a profit, the remainder of which would be socialized among the entire base of ratepayers, even for projects where the need arose specifically out of the capacity needs added by one or more discrete new customers.[291] The record in this Proceeding indicates that, under the Company's interpretation, there is a potential for millions of dollars to be added to rate base to serve specific new customers, which raises concerning questions whether this approach would comply with the directive in SB 23-291.

269. Furthermore, the Commission has implemented new planning processes and probed for additional information to better understand the potential strategies, rates, and other details associated with Public Service's gas system moving forward. The Commission has also discussed at length and taken policy action to proactively try to manage these future expenses, including through requiring gas utilities to make recurring Gas Infrastructure Plan filings and the evaluation of alternatives to capital spending, to ensure that Public Service is taking a prudent path forward. As seen in this rate proceeding, however, capital expenses to maintain and expand the system are drivers of current and future rate increases, and the fact remains the Company retains a strong

[289] Hr. Ex. 123, Matley Supplemental Direct, pp. 9-15; Hr. Tr. September 10, 2024, pp. 142-146.
[290] § 40-3.2-104.3(2)(a), C.R.S.
[291] Hr. Tr. September 4, 2024, p. 128:17–130:6.

profit motive to continue to grow the gas system through new business and the expansion of existing infrastructure, all of which leads to hundreds of millions of dollars in new capital expenses each year, as the record of this case clearly demonstrates.

270. The record in this Proceeding further shows rate projections that anticipate a 40 percent drop in throughput, coupled with a full doubling of base rates for retail customers.[292] Projections in the Company's Clean Heat Plan proceeding stretched out to 2050 and displayed far more dramatic rate increases, especially when compared to the electric system rate projections.[293] Further, the rate projections in this Proceeding did not include any assumption for changes in behavior of transport customers, nor any obvious influence in forecasting of building codes and incentives at all levels, many of which make electrification more attractive for customers and could hasten the rate increases that are already projected. Based on these factors, it is reasonable to conclude that natural gas will likely struggle to compete cost-wise with efficient electric options for heating. The dichotomy of Public Service seeking to profit from the expansion of its system, while also planning to spend $440 million over the next three years to largely reduce load on that same system is striking.[294] Investment in New Business and Capacity Expansion projects makes achievement of the state's clean heat goals for Public Service more difficult and costly, while also making it more difficult to provide affordable natural gas service for those customers who remain on the system, given the pace of investment examined in this Proceeding.

271. Staff focuses significantly on this issue within Ms. O'Neill's Answer Testimony, where she concludes: "Currently, the Company is operating in a 'have its cake and eat it too' environment where it earns on new and existing electric utility infrastructure, earns on new and

[292] Hr. Ex. 123, Matley Supplemental Direct, pp. 19-21.
[293] Decision No. C24-0397 issued in Proceeding No. 23A-0392EG (June 10, 2024).
[294] *See* Decision No. C24-0397.

existing gas infrastructure, earns bonuses for electrification activities, and earns bonuses for gas demand reduction programs. There is no financial incentive for the Company to actively manage or reduce investment in new gas infrastructure and no consequence for poor performance in addressing new growth."[295]

272. Anticipating our discussion here, Public Service states in its SOP that if the Commission seeks to change the Company's line extension policies, for example, those changes should be made on a prospective basis in a different future proceeding.

c. Future Filing Requirement

273. The evidence in this Proceeding regarding New Business projects indicates that Public Service's current cost allocation practices and line extension policies is often socializing costs in a way that subsidizes new growth while fostering significant additions to rate base. In addition, without refocusing or retooling its business model, or without simply adjusting levels of capital investments and overall costs on the system, we are concerned that Public Service is moving toward significant affordability issues for customers who continue to take gas service. Accordingly, the Commission must focus on viable methods to reduce upcoming capital investments, without sacrificing system safety.

274. We further agree with Staff's position in this case that Public Service's compliance with the statutory mandates to reduce greenhouse gas emissions on its system, which the Commission determined for the Company's 2024-2027 Clean Heat Plan will come most cost effectively from reductions in load, conflict with cost socializations and line extension policies that grow profits from investments that increase loads.

[295] Hr. Ex. 401, O'Neill Answer, p. 9.

275. The evidence in this Proceeding further raises significant concerns about Public Service's compliance with the new, express requirement in SB 23-291 that: "A gas utility shall not provide an applicant an incentive, including a line extension allowance, to establish gas service to a property,"[296] especially in instances where investments must be made to serve one or more New Business projects. The evidence also raises the question whether the Company's line extension policy contradicts the provision in the Commission's Gas Rules that prescribes: "Line extension policies, procedures, and conditions shall be based on the principle that the connecting customer pays its share of the estimated full incremental cost of growth, including any costs associated with increases in design peak demand."[297]

276. We therefore order Public Service to submit its Line Extension Policy in a Phase II filing as suggested by Staff. In that new proceeding, the Commission will examine revised policies and new cost allocation for discrete investments necessary to serve new load with specific consideration to the concerns raised by the Commission herein.

277. Turning to Capacity Expansion projects, the evidence in this Proceeding raises concerns that Public Service actively connects new load to its gas system, despite an apparent inability of the existing gas infrastructure to reliably serve the additional load. The projects categorized as Capacity Expansion appear to be after-the-fact efforts completed on an urgent basis once customers are already at risk of loss of service. We surmise that our concern stems from a lack of advanced planning and potentially perverse financial incentives to minimize or eliminate opportunities for the Company, stakeholders, and the Commission to properly evaluate alternatives that may result in cost savings for ratepayers.

[296] § 40-3.2-104.3(2), C.R.S.
[297] 4 CCR 723-4-4210(c).

278. As discussed above, the record in this Proceeding contains examples of multi-million-dollar Capacity Expansion projects, some of which are not supported by any new revenue, as seems to be the case, for example, for the West Metro project. Public Service also appears unable to decipher or explain if certain capacity expansion projects are needed to serve new load or existing load. Therefore, it is difficult to ascertain whether the costs incurred for new customers are cost effective and properly allocated. Further, because capacity expansions upstream generally appear to be completed retroactively—after customers are already at risk of loss of service—it is impossible to assign cost to any new customer responsible for such cost at the time the customer joins the system. This practice, however, may also constitute a prohibited incentive under SB 23-291, and thus should be evaluated in a future proceeding to ensure that the cost of adding new growth is addressed before the addition rather than after the fact.

279. Given these concerns about the recovery of Capacity Expansion costs, the Commission will also examine new cost allocations for investments necessary to maintain system reliability and meet a specified capacity expansion need, including for new customers or facilities that are not otherwise new business projects, or for reliability and growth related to existing customers.[298]

280. SB 23-291 further requires the Commission to open a proceeding to investigate whether and how residential development and other development in certain geographic areas within Public Service's gas system drive infrastructure costs, particularly with regard to the impact that the development has on nonparticipating income-qualified customers.[299] Part of this investigation should seek to determine whether the costs assigned to new customer load additions

[298] Hr. Ex. 105, Gardner Direct, p. 65.
[299] § 40-3-121, C.R.S.

downstream of current or future Capacity Expansion projects can and should include all or a portion of costs of those incremental upgrades that may need to be made upstream in order to accommodate load growth downstream. While the proceeding must commence in the coming weeks, the full scope of the study that will underpin the investigation should continue to be scoped by the Commission and staff and should be undertaken as soon as is feasible such that the outcomes can be incorporated in future relevant proceedings.

281. Accordingly, we direct Public Service to file an advice letter to initiate a base rate class cost allocation and rate design proceeding (*i.e.*, a "Phase II rate case") within nine months of the Issued Date of this Decision. The filing shall include the entire set of tariff sheets within the Company's P.U.C. No. 6-Gas Tariff that comprise its line extension policy and any other policy that may dictate cost allocation of new or upgraded facilities needed to serve new or increased load. The line extension policy shall be comprehensively examined in that future proceeding, including pursuant to the requirement in § 40-3.2-104.3(2), C.R.S., that: "A gas utility shall not provide an applicant an incentive, including a line extension allowance, to establish gas service to a property" and pursuant to Rule 4210(c), 4 CCR 723-4, which states: "Line extension policies, procedures, and conditions shall be based on the principle that the connecting customer pays its share of the estimated full incremental cost of growth, including any costs associated with increases in design peak demand."

II. ORDER

A. The Commission Orders That:

1. The proposed February 29, 2024, effective date of the tariff sheets filed with Advice Letter No. 1029-Gas, filed by Public Service Company of Colorado ("Public Service") on January 29, 2024, is permanently suspended.

2. Public Service shall file an advice letter compliance filing to modify the tariff sheets in its Colorado P.U.C. No. 6 - Gas Tariff consistent with the findings, conclusions, and directives in this Decision. The compliance tariff filing shall include a revised Sheet No. 48 setting forth a General Rate Schedule Adjustment for effect November 5, 2024, calculated to recover the annual revenue requirement based on the findings and conclusions of this Decision. The compliance tariff filing shall also include other tariffs, modified as necessary, to take effect on November 5, 2024, in accordance with this Decision.

3. In accordance with this Decision, the compliance tariff filing shall not include: Sheets 49 through 49B that Public Service proposed to implement a Revenue Deferral Surcharge, Sheets 52 through 52B that Public Service proposed to implement a Revenue Stability Mechanism Adjustment, and Sheets 50A through 50C proposed to modify the Gas Cost Adjustment.

4. Public Service shall file the compliance tariff sheets in a separate proceeding and on not less than two business days' notice. The advice letter and tariff sheets shall be filed as a new advice letter proceeding and shall comply with all applicable rules. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date. The advice letter and tariff must comply in all substantive respects to this Decision in order to be filed as a compliance filing on shortened notice.

5. Consistent with the discussion above, Public Service shall create a trust for future asset retirement obligations.

6. Consistent with the discussion above, Public Service shall present specific scenarios and provide additional information in its forthcoming depreciation study filing.

7. Consistent with the discussion above, Public Service shall: file an update to its 2023 annual report in Proceeding No. 24M-0010EG showing the portion of total compensation of employees that corresponds to their time spent on lobbying after the effective date of SB 23-291; track and report the portion of total compensation for calendar year 2024 and each calendar year through the next rate case for employees who engage in lobbying as defined by SB 23-291; and track internal employee lobbying expenses in a regulatory account starting January 1, 2024, for review in the Company's next rate case establishing base rate revenue requirements.

8. Consistent with the discussion above, Public Service shall extend its gas Quality of Service Plan through December 31, 2026.

9. Consistent with the discussion above, Public Service shall file an advice letter to initiate a class cost allocation and rate design proceeding within nine months of the Issued Date of this Decision.

10. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

11. This Decision is effective immediately upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS OCTOBER 9 & 16, 2024.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E. White,
Director