NOTICE OF CONFIDENTIALITY
PORTIONS OF THIS TESTIMONY AND ATTACHMENTS HAVE BEEN FILED UNDER SEAL.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC 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 EFFECTIVE FEBRUARY 29, 2024	**) PROCEEDING NO. 24AL-______G**

CONFIDENTIAL DIRECT TESTIMONY AND ATTACHMENTS OF JASON J. PEUQUET

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIALITY
PORTIONS OF THIS TESTIMONY AND ATTACHMENTS HAVE BEEN FILED UNDER SEAL.

Redactions: Page 39, 40, 42, 43, and 53

January 29, 2024

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC 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 EFFECTIVE FEBRUARY 29, 2024	)	**PROCEEDING NO. 24AL-______G**

TABLE OF CONTENTS

SECTION **PAGE**

LIST OF ATTACHMENTS

Attachment JJP-1	Rate Case Expense Detail
Attachment JJP-2	Clean Gas Tariffs
Attachment JJP-3	Redlined Gas Tariffs
Attachment JJP-4	Revenue Stability Mechanism and Revenue Deferral Surcharge Timeline

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC 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 EFFECTIVE FEBRUARY 29, 2024	**) PROCEEDING NO. 24AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF JASON J. PEUQUET

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason J. Peuquet. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Public Service Company of Colorado ("Public Service" or the "Company") as Director of Regulatory Administration.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Director of Regulatory Administration, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. A description of my qualifications, duties and responsibilities is set forth in my Statement of Qualifications at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to discuss four primary topics related to the Company's rates and costs, tariff proposals, and other matters in this proceeding: First, I provide context for the Company's rates for natural gas service (including how they compare to other utilities, changes in relation to other prices and income in the national economy, and the Company's efforts to promote stable and affordable gas rates). Second, I support the Company's proposals regarding treatment of certain costs (including Compressed Natural Gas ("CNG") and Liquified Natural Gas ("LNG") costs, trackers and deferrals, rate case expenses, and gas storage inventory costs). Third, I sponsor the updated tariff language stemming from the Company's proposals in this proceeding. Finally, I address compliance items arising from other Commission decisions and rules that are applicable to this proceeding.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring Attachments JJP-1 through JJP-4, which are as follows:

- Attachment JJP-1: Rate Case Expense Detail
- Attachment JJP-2: Clean Gas Tariffs

- Attachment JJP-3: Redlined Gas Tariffs
- Attachment JJP-4: Revenue Stability Mechanism and Revenue Deferral Surcharge Timeline

II. GAS SERVICE VALUE TO CUSTOMERS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the value the Company's gas business provides to its customers today. In exploring this topic, I first discuss how the price for the Company's gas service compares to other leading utilities and how recent changes in gas costs compare to national and local inflation and income trends. Second, I discuss several avenues through which the Company's purchasing and planning practices, Gas Cost Adjustment ("GCA") smoothing mechanism, physical storage reserves, financial hedging program, and potentially other tools support price competitiveness and rate stability for its customers. Third, I discuss the Company's commitment and ongoing efforts to support affordability programs for customers most in need of additional support for their home heating. In addressing these topics, I support the reasonableness of the Company's natural gas rates and overall pricing for customers.

Related to the rate comparisons and rate stability efforts outlined in my testimony, the Company has also included a Rate Trend Report as part of this filing, which is provided as Attachment 1 to the Company's Advice Letter.[1]

---

[1] A Rate Trend Report is required by Senate Bill 23-291 ("SB 23-291") and the Commission's associated temporary Rules 4109(c) and (e), adopted by the Commission in Proceeding No. 23R-0408EG.

A. Price Comparisons and Competitiveness

Q. HOW DO PUBLIC SERVICE'S NATURAL GAS RATES AND AVERAGE MONTHLY BILLS COMPARE TO OTHER GAS UTILITIES IN THE COUNTRY?

A. Our residential natural gas rates are among the lowest in the nation. Even with the increases the Company seeks in this case, Public Service's natural gas residential rates and average monthly residential bills will remain low compared to comparable large utilities across the nation, as set forth in Figure JJP-D-1 below. Based on data from the American Gas Association, using total revenues (including base rates and fuel costs) and volumes for residential customers across the 50 largest gas utilities by customer count, both Public Service's rates and average monthly bills for residential customers in 2022 and the proposed rates and monthly bills in this proceeding, were well below the average among the top 50 largest utilities. This is the case even though many of the largest gas utilities did not have to contend with extraordinary gas fuel costs from Winter Storm Uri in 2021 (as reflected in the Company's Extraordinary Gas Cost Recovery Rider ("EGCRR")), nor significantly elevated gas fuel costs in 2022. Additionally, not all gas utilities are as focused on the clean energy transition as Public Service and the Commission, which also comes at a cost.

Figure JJP-D-1
Residential Average Rate Comparison of Gas Utilities

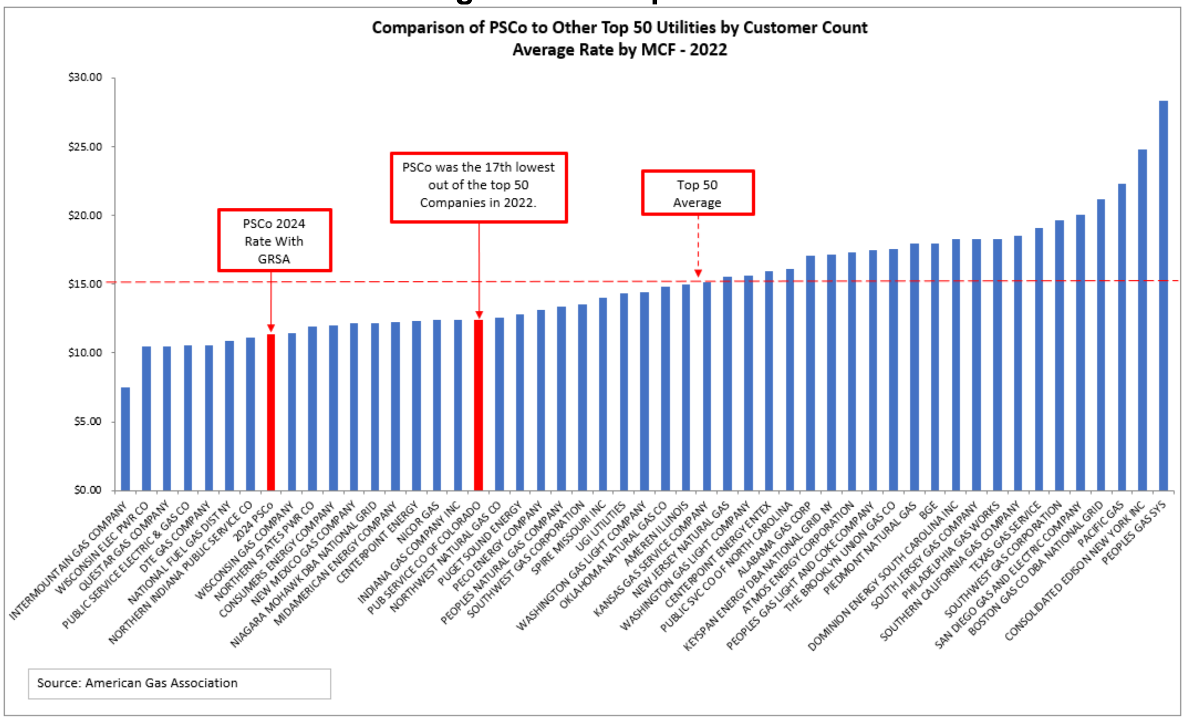
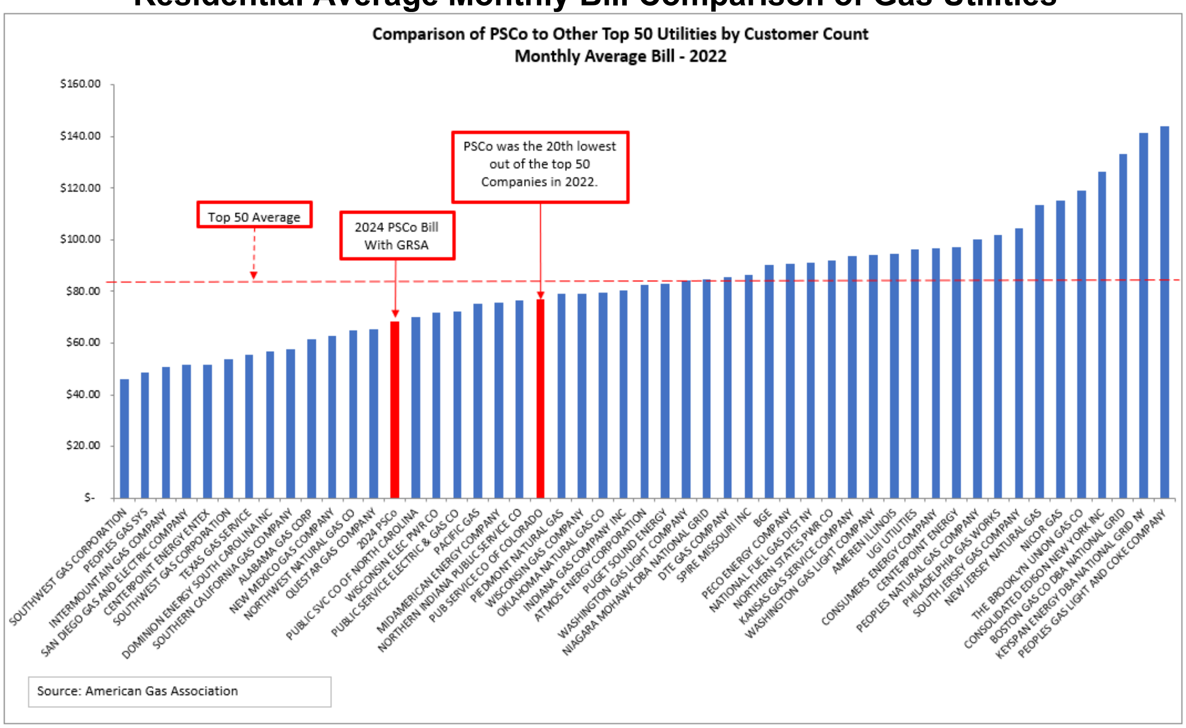


Figure JJP-D-2
Residential Average Monthly Bill Comparison of Gas Utilities



Q. CAN YOU PROVIDE MORE CONTEXT FOR THIS INFORMATION?

A. Yes. As shown above, 2022 had very high gas costs, which is why the Company's bill and rate impacts are actually lower than what occurred in 2022 if the 2024 General Rate Schedule Adjustment ("GRSA") is implemented as proposed. Further, the Figures above demonstrate that both Public Service's current and proposed rates and bills are well below the national average compared to other utilities' 2022 data;[2] however, the last several years have seen near record-high rate case activity across the country, so it is likely that many of these peer utilities have also increased base rates since this data was provided. Overall, the data demonstrates that the Company's average residential bills and rates remain below average.

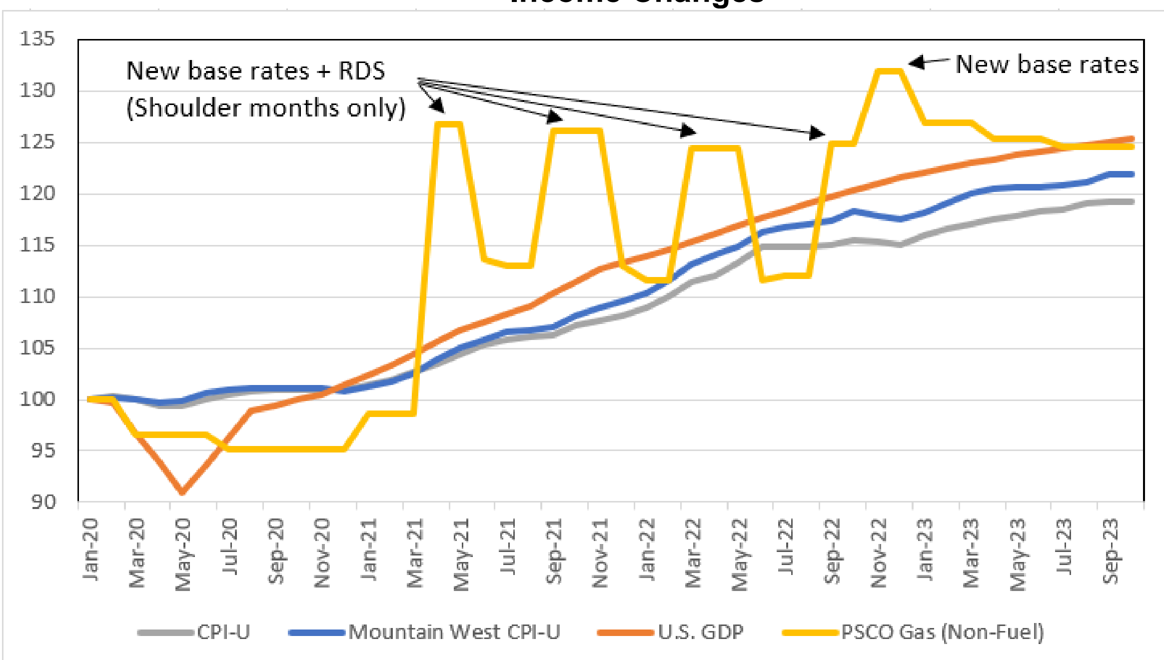
These below-average rates do not happen by accident. They are the result of years of Company work developing robust internal planning, purchasing, and execution strategies to control costs. Even as Public Service must meet its obligations to serve customers under conditions that reflect high inflation, tight labor markets, and increased costs, maintaining affordable and stable rates for customers is a high priority for the Company, as I will continue to discuss in this section of my testimony.

[2] The Company presents 2022 data because 2023 data is not yet available at the time of filing the Company's Direct case.

Q. HOW HAVE PUBLIC SERVICE'S GAS RATE CHANGES COMPARED TO OTHER CHANGES IN PRICES AND INCOMES IN THE ECONOMY?

A. As illustrated in Figure JJP-D-3 below, the Company's non-fuel rates[3] have largely stayed in line with United States Gross Domestic Product growth in recent years and are on the same trajectory with changes in inflation since 2020.

Figure JJP-D-3:
Comparing Public Service Gas Non-Fuel Rates to National Price and Income Changes



Note: Public Service Gas rates reflect $/therm and exclude GCA and EGCRR riders. January 2020=100.

When indexing changes compared to January 2020, the Company's non-fuel gas rates vary based on the timing of particular base rate changes and rider changes taking effect, including new base rates taking effect in 2020, 2021, and

[3] The reference to non-fuel rates includes the service and facilities charge, base rate charges, Demand-Side Management ("DSM") charge, former Pipeline System Integrity Adjustment ("PSIA") rider (when applicable), the Revenue Deferral Surcharge (when applicable), and General Rate Schedule Adjustments ("GRSAs") (when applicable).

2022; Winter Storm Uri costs starting to be recovered in 2022 (after being incurred in February of 2021); changes in recovery of pipeline system costs across the PSIA and GRSA-P; and the application of the Revenue Deferral Surcharge from our 2020 gas rate case taking effect only in shoulder months and ending in 2022; among other rate changes. However, on average the Company's non-fuel rates have increased in line with other price and income changes in recent years.

Q. HOW IS THE COMPANY MANAGING COSTS TO SUPPORT PRICE COMPETITIVENESS?

A. As discussed by Company witness Mr. Adam Dietenberger, the Company deploys robust processes to develop bottom-up budgets each year, assessing needs and appropriate changes to scopes of work as needed. These budgets are subject to rigorous governance processes that involve department accountability and executive oversight, and then the Company implements projects in adherence to budgets to the extent possible, with reviews for variances (and special governance processes for any larger variances). Within these processes, the Company must also be ready to respond to emergencies, unexpected changes for the business or customer needs, or statewide or local policies and the associated budget impacts those may have. Company witnesses Lauren Gilliland, Ray Gardner, Megan Scheller, Adam Dietenberger, Michael Deselich, and Richard Schrubbe all describe in various ways how the Company's robust planning and implementation procedures help control costs and produce prudent levels of spending across the business. Specifically, Company witness Lauren Gilliland discusses some benchmarking data on operations and maintenance ("O&M") expenses among nearly 90 other regulated utilities, which finds that in 2022 (the latest year for which data is available), Public Service O&M costs per end-use customer are safely in the top quartile.

Overall, the Company works diligently every day to keep rates low for customers – one of the three central objectives for Xcel Energy and its operating companies. Our success in largely keeping pace with broader price and income changes in the economy, while at the same time providing our customers with safe and reliable gas service, is a result that the Company and all engaged stakeholders should be proud of.

B. <u>Rate Stability</u>

Q. IN ADDITION TO THE COMPANY'S WORK TO KEEP BILLS LOW FOR CUSTOMERS, DOES THE COMPANY WORK TO PROMOTE BILL STABILITY?

A. Absolutely. The efforts I described above with respect to cost containment for base rate contribute to overall bill stability, which relates to both keeping bills low and to avoiding unpredictable bills for customers. The Company also looks for ways to keep customers' overall bills from rising unexpectedly during the coldest parts of winter. Figure JJP-D-3 above demonstrates the Company's enactment of a revenue deferral mechanism in our 2020 Combined Gas Rate Case[4] to help mitigate the impact of a Commission-approved rate increase during the 2020/2021 and 2021/2022 heating seasons. This proposal helped smooth bills and contain costs for customers during the height of the COVID-19 pandemic, but delayed

[4] Proceeding No. 20AL-0049G.

implementation of new rates on customer bills to shoulder months (outside of the key heating and cooling seasons). Additionally, in Public Service has offered prior gas rate case proposals to implement base rate changes gradually over a multi-year period to better match rates with expected cost growth and incremental investments made. While these proposals were not approved by the Commission, such mechanisms can serve to directly promote consistent, stable, and predictable rates. The Company continues to look for ways to achieve these goals throughout its rate case filings.

Q. DOES THE COMPANY TAKE OTHER STEPS TO SUPPORT BILL STABILITY?

A. Yes. On the fuel cost side, through a combination of gas purchasing strategies, gas storage reserves, financial hedging, a recently-proposed plan to rely on fixed price gas contracts for a portion of the Company's baseload needs (pending in the Company's Gas Price Volatility Mitigation ("GPVM") in Proceeding No. 24A-0039G), and the newly approved and implemented Gas Price Risk Management Plan ("GPRMP"), the Company works hard to promote bill stability for customers.

Q. DOES THE COMPANY PROPOSE ANY MECHANISMS IN THIS RATE CASE TO PROMOTE RATE STABILITY FOR CUSTOMERS?

A. Yes. As discussed in more detail by Company witness Mr. Steven P. Berman, the Company proposes a mechanism in this proceeding to delay implementation of new gas base rates on customer bills until February 15, 2025, deferring approved incremental revenue in the interim from the November 1, 2024 proposed rate effective date in this case (after suspension). This proposal is specifically designed to promote rate stability by delaying the effect of increased rates in this case until the separate Winter Storm Uri rider charge (EGCRR) is removed. This will directly promote rate stability for customers by ensuring that there is not an increase in base rates on their bills leading into the 2024-2025 heating season, with continued rate stability thereafter. This proposed mechanism is similar to the former Revenue Deferral Surcharge I discussed above.

Q. PLEASE DISCUSS HOW THE COMPANY PROMOTES STABILITY IN FUEL COSTS IN ADDITION TO BASE RATES.

A. Regarding well-established and prudent gas purchasing processes, the Company relies on several strategies that cumulatively help both to provide competitive natural gas fuel rates for customers and some rate stability. These strategies include the advance purchase of seasonal and monthly baseload quantities likely to be needed, making daily and intra-day purchases when needed, geographic diversity of gas purchases and deliveries, and (more recently) economic-based messaging with customers to help reduce the impact that price spikes in commodity costs could have on their bills.[5]

In addition to gas purchasing strategies, the Company's customers benefit from the continued use of geologic gas storage fields in which the Company leases space. These storage fields are a critical resource supporting the Company's efforts to provide reliable service to customers, as well as stable and affordable rates. The Company also supplements the use of physical gas storage with the targeted use of financial hedging products. This financial hedging acts as an

[5] The Company's recent comments in Proceeding No. 23M-0493EG, where the Commission is exploring possible structures and considerations for a fuel performance incentive mechanism, address these purchasing strategies in more detail.

insurance policy if or when the Company needs to rely on them to help provide rate stability for customers.

The Company also recently proposed and received approval for its GPRMP, which is a new mechanism applied to the quarterly GCA that helps smooth out natural gas fuel costs for customers by restricting GCA rates to between 80-180 percent of the previous five-year average. The Company hopes to build up a reserve fund during times when gas prices are low in order to help moderate prices when they rise to levels above historical averages.

Q. IS THE COMPANY WORKING TO PURSUE ANY ADDITIONAL MECHANISMS TO PROMOTE AFFORDABLE AND STABLE NATURAL GAS BILLS FOR CUSTOMERS?

A. Yes. As the Company discusses in its recently filed GPVM plan (Proceeding No. 24A-0039G), the Company plans to pursue fixed price gas contracts, in limited quantities at first, when market conditions may look appealing for doing so. In today's environment of increased gas price volatility, as a result of increased global use of LNG, changing weather patterns, and ongoing geopolitical conflicts, having an additional tool in the toolbox to help lock in competitive gas costs for a portion of customers' needs can help the Company pursue rate stability.

Q. ARE THERE OTHER ONGOING DISCUSSIONS AT THE COMMISSION THAT COULD IMPACT NATURAL GAS COSTS AND BILL STABILITY?

A. Yes. As noted earlier, the Company is participating in the Commission's exploration of possible fuel cost incentive mechanism designs in Proceeding No. 23M-0493EG. Spurred by Senate Bill 23-291 ("SB 23 291"), the Commission is revisiting fuel cost performance incentive mechanisms that seek to "protect customers" and improve "the utility's management of fuel costs," considering symmetrical incentives and other parameters through the process.[6] While still ongoing, the result of these discussions and any follow-on rulemaking could affect natural gas costs and the stability of those costs passed through to customers, along with any associated rewards or penalties for the Company.

Q. HOW DO THESE EFFORTS INTERRELATE WITH THIS RATE CASE?

A. While the Company's proposals in this proceeding would increase base rates to be reflective of largely historical capital investments and incurred costs, the change in rates should be viewed holistically as part of a broader environment in which the Company, the Commission, Colorado lawmakers, and interested stakeholders are pursuing new tools and regulatory mechanisms to promote rate and bill stability. In fact, the Company proposes a revenue deferral mechanism in this proceeding to delay the implementation of new base rates on customer bills until the recovery of costs related to Winter Storm Uri conclude in February 2025. Furthermore, this discussion illustrates that base rates are but one component of customers' monthly bills, and the Company is pursuing rate stabilization tools across base rates and fuel costs, which together comprise the majority of monthly costs for customers receiving gas service.

---

[6] *See* § 40-3-120(2)(b-c), C.R.S.

C. Affordability

Q. IN ADDITION TO THE FOREGOING, HOW DOES THE COMPANY SUPPORT GAS SERVICE AFFORDABILITY FOR CUSTOMERS?

A. In addition to the foregoing efforts, the Company promotes rate affordability directly through programs targeted to those facing more acute needs for support on home energy costs. Specifically, through the Company's Gas Affordability Program ("GAP"), the Company works closely with the State of Colorado, the Colorado Energy Office, and Energy Outreach Colorado (in addition to other organizations and customers directly) to provide support on monthly gas bills to qualifying customers.

Q. BEFORE ADDRESSING THE COMPANY'S PROGRAMS, HOW DOES COST FACTOR INTO ASSESSMENTS OF THE AFFORDABILITY OF ENERGY SERVICES?

A. As the Commission has indicated, affordability is and should be a central consideration in all of its work.[7] However, it is important to note that affordability is a function of cost, the benefits provided, and the resources available to the customer that will not be the same for all customers. Available resources may include the customers' own income, as well as supportive programs provided to those customers who need them (which I describe in more detail below). Thus, it would not be appropriate to characterize affordability solely in relation to the cost-side of the equation.

[7] *See* the Commission's "Affordability Initiative Initial Work Plan" from April 2023, and other components of the Commission's focus on affordability, at https://puc.colorado.gov/affordability.
.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "THE BENEFITS PROVIDED."

A. The natural gas the Company provides heats customer's homes and businesses at all times, including during the coldest days of the year; fuel that powers residential and commercial kitchens; feedstocks for industrial processes; and supply for natural gas electric generation facilities that provide electrical capacity at all times including the hottest days of the year. It is a critical service that powers our communities and economy. Along with the benefits of the commodity itself come the benefits of regulated natural gas service, which include obligations to provide service to customers, direct oversight of activities and regulation of rates of return, emergency response to reported leaks, and continuous safety and integrity monitoring and investment in the existing gas system to maintain safe and reliable service.

Q. TURNING TO THE COMPANY'S AFFORDABILITY PROGRAMS, HAVE ENHANCEMENTS TO THOSE PROGRAMS RECENTLY BEEN MADE?

A. Yes. In Spring 2023, the Company worked collaboratively with several organizations – including Trial Staff, the Colorado Office of the Utility Consumer Advocate ("UCA"), Energy Outreach Colorado ("EOC"), and the Chronic Care Collaborative – to think through how its Electric Affordability Programs ("EAP") and GAP could be further enhanced to support the home energy needs of customers facing more acute energy burdens and requiring assistance not then available under our programs. Importantly, the identified need was not limited to those currently participating, but more broadly considered how the Company's programs could be expanded so that an increased number of customers receive assistance.

The Company ultimately proposed several program modifications,[8] all of which were allowed to go into effect by operation of law.[9] As a result of these requests, funding was increased by approximately $47 million for both EAP and GAP, with approximately $21 million of that increase associated with GAP.

Q. WHAT ROLE DO AFFORDABILITY PROGRAMS PLAY IN THE CONSIDERATION OF THIS RATE CASE?

A. It is not unusual for Public Service to file a rate case, and then for an intervening party or parties to assert in partial response that affordability concerns mean the Company's requests should be rejected in whole or in part. While there is no doubt that rates must be just and reasonable for all customers, there are broader and more complex considerations around affordability than cost increases alone. Rather, it is important to consider that costs are rising for the utility as well as for customers, that the utility has an obligation to provide safe and reliable service to all customers who seek it, that customers – even customers within a single rate class – are not all in the same financial circumstances when it comes to be able to afford utility services, that Public Service provides excellent value via the services it renders and the costs it charges, and that Public Service works diligently to support those customers who need affordability assistance. Overall, it is important

---

[8] The program enhancements included increasing funding to accommodate new participants from newly eligible pathways to participation, enrolling customers previously deemed eligible due to high arrears and/or sufficiently low income but face acute home energy challenges, retiring arrears for program participants (subject to available funding), and excluding LEAP and EOC benefits when calculating EAP and GAP benefits.

[9] Decision No. C23-0364 in Proceeding No. 23AL-0177G granted several requested variances from Commission rules.

to view affordability considerations in a rate case from this broad-based, nuanced perspective.

Q. DO YOU HAVE ANY CONCLUDING COMMENTS IN RELATION TO THE VALUE OF PUBLIC SERVICE'S GAS SERVICE?

A. Yes. Public Service centers its business model on excellence in gas service and the customer experience, while keeping bills as low as possible. While Public Service must seek recovery of the significant investments it has made since 2021 in order to protect the Company's health, we do so while working to ensure the Company's services provide value, rates are reasonable, bills are reasonably stable, and customers have access to energy assistance when it is needed. In the remainder of my testimony, I speak to various specific costs, proposals, and information that are part of Public Service's overall requests.

III. CNG AND LNG

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I address the costs associated with LNG and CNG[10] in this case from a regulatory perspective, providing additional support for the broader discussion of how the use of these resources is helping to maintain reliable service for customers at reasonable costs. In doing so, I seek to align the costs and discussion in this case with the consideration of CNG and LNG in a currently pending and separate proceeding before the Commission.[11] Company witness Stephen G. Martz separately discusses the forward-looking use of LNG and CNG to support capacity-constrained points on the system while non-pipeline alternatives ("NPAs") are being assessed and/or deployed, and Company witness Lauren Gilliland discusses in more detail the Company's targeted deployments of CNG and LNG in the Test Year.[12]

Q. PLEASE EXPLAIN WHAT ROLE, IF ANY, THE COMPANY'S COSTS ASSOCIATED WITH CNG AND LNG PLAY IN THIS PROCEEDING.

A. The Company has included roughly $6.2 million in the cost of service that stems from costs incurred in the Test Year that were associated with third-party LNG services. The Company and its service providers developed a temporary site in

[10] "CNG" sometimes is used to mean certified natural gas; however, in this testimony CNG refers to Compressed Natural Gas.
[11] Decision No. R24-0059 in Proceeding No. 23AL-0325G was issued on January 25, 2024 just before the submission of the Company's Direct Testimony in this proceeding. The Company is reviewing the decision and will further address any interactions between these two proceedings in Rebuttal Testimony, as necessary.
[12] The Test Year is the 12 months ended December 2023. Company witness Mr. Berman discusses the components of the Test Year in more detail.

Breckenridge, Colorado to enable the injection of LNG into the Company's gas facilities to help meet design day capacity requirements while other solutions are being explored. The costs associated with the site include site preparation and civil engineering work, fencing, equipment rentals, transportation, operational support, and the commodity cost for the delivery of LNG to the Company's site in Breckenridge.

The Company also incurred about $0.6 million in costs associated with third-party CNG services at several locations throughout the Company's service area – including at various times in Keystone, Aurora, Lyons, Mead, Longmont, Boulder, Grand Lake, and Pagosa Springs in the 2022-2023 and/or 2023-2024 heating seasons. The costs incurred for CNG cover both Company-owned assets, such as several CNG gas transport tanks, in addition to third-party services for the commodity and its transport.

In addition to discussion in my Direct Testimony and that of Company witnesses Lauren Gilliland and Mr. Martz in this proceeding, the Company provides more background on the use of CNG and LNG in its operations, and the factors considered when deciding when and where to deploy them and which supplemental resource to use in certain situations, in its Direct and Rebuttal Testimonies in Proceeding No. 23AL-0325G.

Q. HOW IS THE USE OF THIRD-PARTY CNG AND LNG BEING DISCUSSED IN PROCEEDING NO. 23AL-0325G?

A. In Proceeding No. 23AL-0325G, the Company sought approval to make a few targeted revisions to language in its GCA tariff pages to explicitly mention LNG and other gas commodity purchase costs within the definition of "Actual Gas Cost." The targeted tariff modifications in that proceeding would provide a clear avenue through which the Company could bring forward third-party CNG and LNG costs for recovery through the GCA. This proceeding is ongoing and was brought forward in order to respond to the Commission's directive that "If Public Service wishes to include [third-party LNG and CNG costs] in its GCA, we instruct the Company that such inclusion must be based on substantially more information than presented in this [January 2023 GCA filing] record."[13] No specific cost recovery is currently at issue in Proceeding No. 23AL-0325G. I discuss the cost recovery relationship between that proceeding and this rate case in more detail below.

Furthermore, the use of CNG and LNG has also been a topic of discussion in the Company's Initial Gas Infrastructure Plan in Proceeding No. 23M-0234G. In that proceeding, the Company outlined the ability of CNG and LNG to act as a bridge to facilitate the implementation of a cost-effective NPA portfolio and to reduce the reliance where feasible on long-lived gas infrastructure investments; however, cost recovery paths for CNG and LNG are not directly at issue in the Initial Gas Infrastructure Plan ("GIP"). As such, this topic in the GIP is largely informational.

[13] Decision No. C23-0059, ¶24 in Proceeding No. 23L-0040G.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THE CONVERGENCE OF THE SEPARATE AND ONGOING PROCEEDING REGARDING RECOVERY PATHS FOR CERTAIN LNG AND CNG COSTS?

A. The Company has included all costs incurred regarding CNG and LNG during the 2023 Test Year in the proposed revenue requirement in this case, including costs related to Company-owned assets (in limited instances) and third-party services, as discussed at the beginning of this section. This is consistent with the Company's practice in prior rate cases. In the event the Commission ultimately approves the Company's tariff modifications regarding recovery of CNG and LNG commodity costs in Proceeding No. 23AL-0325G, then the Company may pursue cost recovery of appropriate third-party costs through the GCA rather than through base rates. If the Company were to actually recover certain CNG and LNG costs through the GCA, then the Company would update its base rate requests in this proceeding in Rebuttal Testimony to ensure costs are only recovered through one procedural avenue and that there is no double-counting.

IV. TRACKERS AND DEFERRALS

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this portion of my Direct Testimony, I describe the Company's current and proposed cost recovery deferral mechanisms for property taxes, pension expense, Commission administration fee expenses, damage prevention costs, and the Company's proposal for an Information Technology ("IT") cost deferral mechanism. In doing so, I identify and support the Company's ratemaking proposals for: (1) amortizing these costs for purposes of setting base rates in this proceeding; (2) setting the base amount of each type of expense in base rates; and (3) initiating or continuing each of these deferrals, as applicable, until they are further reviewed in a subsequent Gas Phase I rate case. I also discuss the current status of Manufactured Gas Plant ("MGP") investigation, remediation, and defense costs associated with the Rice Yards and Crown Tar Works Sites (collectively, the "Denver Sites" or "Sites"), for which we do not seek a new amortization in this case. Mr. Arthur P. Freitas further discusses the MGP deferred balance and amortizations in his Direct Testimony.

A. Deferral Balance Amortization Periods

Q. WHAT AMORTIZATION PERIODS DO YOU RECOMMEND FOR THE DEFERRAL MECHANISMS PROPOSED IN THIS PROCEEDING?

A. I recommend an 18-month amortization period for all the deferred amounts for which we seek recovery in this case, with the exception of rate case expenses.

Mr. Freitas explains that the Company proposes to include the unamortized tracker balances[14] in rate base, where they will earn a return at the Company's weighted average cost of capital ("WACC").

Q. HOW DID YOU ARRIVE AT THE AMORTIZATION PERIOD FOR THE REFERENCED DEFERRED ASSETS?

A. The Company strives to set an amortization period that is aligned with the time period expected between rate cases. This allows amortizations to run their course between rate cases. The Company has proposed a test year in this case consisting of the twelve months ended December 2023. The regulatory lag associated with a 2023 Test Year likely being the basis for rates that will not take effect until November 2024, coupled with the need for continued capital investment in the gas system to maintain safety and reliability, and overall inflationary impacts, will continue to put pressure on the Company's need for rate relief. As a result, 18 months beginning November of 2024 is a reasonable estimate for the need for future base rate relief in the form of a subsequent rate case proceeding. Furthermore, an 18-month amortization period for deferred amounts aligns with the Commission's decisions on amortizations in the Company's last gas rate case, in which an 18-month period was awarded for the pension tracker, property tax tracker, and the damage prevention tracker as proposed by the Company.[15] There is no compelling reason to alter this treatment of tracked or deferred expenses

[14] There is no unamortized balance for Commission Administration Fees in this case.
[15] Proceeding No. 22AL-0046G, Decision No. C22-0642 at ¶¶ 218, 222, and 229.

given that the overarching regulatory and recovery structures proposed in this case closely mirror those reflected in the outcome of the Company's last gas rate case.

Q. WHAT AMORTIZATION PERIOD DO YOU PROPOSE FOR RATE CASE EXPENSES?

A. The Company is proposing a 36-month amortization period for rate case expenses in this proceeding. This is consistent with the Commission's direction in the last rate case, finding that precluding the Company from achieving full recovery of rate case expenses incurred until 36 months after final rates took effect encouraged the Company to manage its level of rate case expenses. While the Company already is incentivized to manage rate case expenses, it is aligning its amortization of rate case expenses to reduce the number of issues in this case. Furthermore, the Company recognizes that the topic of rate case expenses and their recoverability will be discussed further in a future rulemaking, which may include certain limits and/or symmetrical incentives, per a recent directive from Colorado lawmakers via SB 23-291. As a result, the Company is proposing a continuation of current treatment on rate case expenses and is not altering the amortization period.

Q. WHAT WILL THE COMPANY DO IF RATES FROM THE NEXT RATE CASE ARE EFFECTIVE BEFORE THE APPROVED AMORTIZATION PERIOD EXPIRES?

A. The Company will propose to include any projected remaining balance that will not be amortized prior to the effective date of rates in the next Phase I rate case in the cost of service for that rate case. Those balances will be subject to the amortization period proposed in that case.

B. Continuing and New Trackers and Deferrals

1. Continue Property Tax Tracker

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE PROPERTY TAX DEFERRAL APPROVED BY THE COMMISSION.

A. In Proceeding No. 15AL-0135G (the "2015 Gas Phase I Rate Case"), Staff proposed that the Commission implement a property tax tracker by which "the Company will defer and establish a regulatory asset for each year until the next gas rate case for costs that differ, above or below, the actual property tax costs incurred, and the amount of property tax costs in the cost of service for the 2014 HTY."[16] Staff further recommended that the Commission address the amortization period for the recovery of deferred property tax cost in the Company's next gas rate case.[17] The Commission approved Staff's proposal.[18]

The Commission has since allowed the Company to continue the property tax tracker on a going-forward basis,[19] with the baseline set at $62,784,917 in Proceeding No. 22AL-0046G (the "2022 Combined Gas Rate Case"). Company witness Ms. Leah Lovley also discusses property taxes in her Direct Testimony.

---

[16] Proceeding No. 15AL-0135G, Decision No. R15-1204 at ¶ 235.
[17] Proceeding No. 15AL-0135G, Decision No. R15-1204 at ¶ 235.
[18] Proceeding No. 15AL-0135G, Decision No. R15-1204 at ¶ 237.
[19] See Proceeding No. 17AL-0363G, Decision No. R18-0318-I at ¶ 270; Proceeding No. 20AL-0049G, Decision No. R20-0673 at ¶ 57.

Q. IS PUBLIC SERVICE PROPOSING TO CONTINUE THE PROPERTY TAX TRACKER ON A GOING-FORWARD BASIS?

A. Yes. On a going-forward basis, Public Service proposes to establish the tracker baseline at $71,990,242, which is the property tax expense forecasted for calendar year 2024, as discussed by Mr. Freitas, and to defer the actual property taxes that are higher or lower than the baseline for recovery in a future case. Continuation of the tracker is consistent with decisions in prior rate cases, including the 2022 Combined Gas Rate Case.

Q. WHY IS THE COMPANY PROPOSING TO CONTINUE THE PROPERTY TAX EXPENSE TRACKER?

A. The property tax tracker has been a reasonable policy implemented by the Commission. Property taxes are unique costs; they arise from investments made by the Company to provide safe and reliable service. Other than challenging valuations, the Company has no control over the amount of property taxes assessed by the various taxing jurisdictions, and those costs help fund schools and local governments. Ultimately, the property tax tracker and the deferral mechanism help ensure that Public Service recovers in rates no more and no less than the actual amount of property taxes.

2. Continue Pension Expense Tracker

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE PENSION EXPENSE TRACKER.

A. Similar to the property tax tracker, Staff proposed in the 2015 Gas Phase I Rate Case that the Commission approve a pension tracker to ensure that customers were not required to pay more than the actual amount of qualified and non-qualified pension expense.[20] The Commission approved the pension tracker and established a baseline against which to track the pension expense.[21] The Commission has since approved the Company's continuation of the pension expense tracker, and the pension tracker baseline established in the 2022 Combined Gas Rate Case was $4,572,516 for both qualified and non-qualified pension expense. Company witness Mr. Richard R. Schrubbe discusses the pension tracker issue in his Direct Testimony.

Q. WHAT IS THE COMPANY'S PROPOSAL GOING FORWARD AS IT RELATES TO THE PENSION EXPENSE TRACKER?

A. Public Service proposes to continue the pension expense tracker and to defer the difference between the baselines and the actual amounts of qualified and non-qualified pension expense. As explained by Mr. Freitas in his Direct Testimony, the going-forward baseline should be set at $1,655,222 for qualified pension expense and $110,550 for non-qualified pension expense for the Test Year. Those expenses are supported by Mr. Schrubbe.

---

[20] Proceeding No. 15AL-0135G, Decision No. R15-1204 at ¶ 233.
[21] Proceeding No. 15AL-0135G, Decision No. R15-1204 at ¶ 233.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO CONTINUE THIS TRACKER?

A. The tracker and deferral for pension expense have worked well since being implemented in 2015, and therefore the Company proposes to continue them. Pension expense has a relatively high probability of varying from forecasted levels, and these are legitimate costs of service and are key to attracting and maintaining a qualified workforce. Ultimately, this deferral provides appropriate customer protections (if actual expense is less than forecast) and helps customers through the retention of a quality workforce.

3. Continue Commission Administration Fees Tracker

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE COMMISSION ADMINISTRATION FEES TRACKER.

A. The Company, like all electric and gas utilities regulated by the Commission, pays an annual Commission administration fee to fund the Commission, its Staff, and other agencies within the Colorado Department of Regulatory Agencies. That fee is assessed to each utility based on a percentage of the utility's annual revenue in the prior year. In Proceeding No. 22AL-0046G, the Commission approved the deferral of such fees. The deferral of the Commission administration fees was permitted by Senate Bill 21-272, which also increased the cap on the percentage of revenue a utility can be charged from 0.25 percent to 0.45 percent. The Commission administration fees tracker baseline was established in the 2022 Combined Gas Rate Case was $3,797,021.

Q. WHAT IS THE COMPANY'S PROPOSAL GOING FORWARD AS IT RELATES TO THE COMMISSION ADMINISTRATION FEES TRACKER?

A. The Company proposes to continue to defer these fees. Because these fees are calculated as a percentage of total revenue, inclusive of fuel revenue, and total revenue varies between rate cases (particularly fuel revenue), it is reasonable to maintain a deferral above or below the baseline amount of Commission administrative fees set in this case. The tracker ensures that customers pay the amount of Commission administration fees incurred by Public Service. As explained by Mr. Freitas in his Direct Testimony, the going-forward baseline should be set at $4,482,360 for the 2023 Test Year.

4. Continue Damage Prevention Program Tracker

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON RATEMAKING TREATMENT WITH RESPECT TO THE COMPANY'S DAMAGE PREVENTION PROGRAM.

A. In the 2015 Gas Phase I Rate Case, the Commission approved Staff's proposal that Public Service be authorized to establish a regulatory asset to defer the difference between the actual costs incurred for damage prevention and the amount of damage prevention expense included in base rates.[22] In Proceeding No. 17AL-0363G (the "2017 Gas Phase I Rate Case"), the Commission approved the Company's request to continue deferring the difference between the actual costs incurred for damage prevention and the amount of damage prevention costs

[22] Proceeding No. 15AL-0135G, Decision No. R15-1204 at ¶ 210.

included in base rates.[23] In the 2020 Combined Gas Rate Case, the Commission approved the Company's request to continue deferring the difference between the actual costs incurred for damage prevention and the amount of damage prevention costs included in base rates.[24] In the 2022 Combined Gas Rate Case the Commission again approved the Company's request to continue the damage prevention deferral.[25] Company witness Ms. Lauren Gilliland discusses the damage prevention program.

Q. WHAT IS THE COMPANY'S PROPOSAL GOING FORWARD AS IT RELATES TO THE DAMAGE PREVENTION TRACKER?

A. As supported in more detail by Ms. Gilliland, Public Service proposes to continue the damage prevention expense tracker and to defer the difference between the baseline and the actual amounts of damage prevention expense. As Mr. Freitas explains further in his Direct Testimony, the Company requests the Commission set the baseline at $32,014,705. This baseline amount is supported by Company witness Ms. Gilliland.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO CONTINUE THIS TRACKER?

A. The tracker and deferral for damage prevention expense are appropriate because the costs are out of the Company's control and are unpredictable. The costs are driven by the actions of customers and contractors, rather than Public Service, and

[23] Proceeding No. 17AL-0363G, Decision No. R18-0318-I at ¶ 277.
[24] Proceeding No. 20AL-0049G, Decision No. R20-0673 at ¶64, ¶113-126.
[25] Proceeding No. 22AL-0046G, Decision No. C22-0642 at ¶66-67, ¶227-229.

the Company's response to requests for damage prevention locates is mandated by law, as discussed in more detail by Ms. Gilliland.

5. Status of Manufactured Gas Plants ("MGP") Cost Recovery

Q. WHAT IS A MANUFACTURED GAS PLANT?

A. During the 1800s, thousands of MGPs (often referred to as town gas plants) operated in the United States and provided fuel for cooking and lighting for the towns that they served, similar to natural gas companies today. Most large towns and cities had one or more MGPs to manufacture the gas. Different gas production processes and fuels were used by MGPs, but generally coal and/or petroleum was heated to high temperatures. This produced raw gas that was conditioned and stored in tanks. The gas was then used as fuel throughout the community. By the 1960s, MGP production was replaced by natural gas service as a network of natural gas pipelines was built across the country.

Q. WHAT ARE THE RICE YARDS AND CROWN TAR WORKS SITES?

A. The Rice Yards Site is a 67-acre property in the Central Platte District of Denver, Colorado, and is the site where a former MGP was once located. There have been various owners and/or operators of the Rice Yards Site over time, including Public Service. The former Crown Tar Works Site is adjacent to the Rice Yards Site and was a tar recovery plant. It is believed that contamination from historical industrial operations of the Crown Tar Works Site and the Rice Yards Site may be commingled. The MGP at the Rice Yards Site manufactured gas from approximately 1889-1928. On September 19, 1927, Public Service obtained the rights to distribute natural gas to Denver and, on July 1, 1928, gas production at the MGP ceased. The MGP was maintained for potential emergency use by Public Service until approximately 1942.

Q. PLEASE DESCRIBE DENVER'S CLAIMS REGARDING THE RICE YARDS SITE.

A. In 2017, Denver alleged that it had discovered and remediated MGP wastes at Shoemaker Plaza in Confluence Park. Denver asserted that MGP wastes had originated from the Rice Yards Site and migrated to Shoemaker Plaza, and that the Company was responsible for paying for the investigation, remediation, and delay costs associated with its alleged discovery. Denver's demand for cost recovery at that time exceeded $4 million. As discussed below, the Company reached a settlement with Denver regarding these claims.

Q. PLEASE ELABORATE ON THE SETTLEMENT THE COMPANY REACHED WITH DENVER REGARDING THESE CLAIMS.

A. In August of 2018, the Company reached a cooperation and settlement agreement with Denver. Under the settlement, in exchange for releases from Denver, the Company contributed $850,000 to Denver's Environmental Services Capital Fund to reimburse Denver for its investigation and remediation costs at Confluence Park related to the Rice Yards Site, and the Company agreed to provide future funding (up to a maximum of $500,000) for a joint environmental investigation of the Rice Yards Site and nearby areas. That investigation is now complete.

The settlement itself was for significantly less than Denver's demand and resolved Denver's claims for investigation and remediation costs at Confluence

Park for contamination originating from the Rice Yards Site, both past and future, and avoided significant costs of continued civil litigation of Denver's claims. The settlement also provided for a joint investigation of the potential source area at the Rice Yards Site.

Q. PLEASE DESCRIBE KRS'S[26] CLAIMS REGARDING THE RICE YARDS SITE.

A. KRS is the current owner of property at the Rice Yards Site. KRS intends to redevelop all or portions of the property as a high-rise, multi-use, urban community. The planned redevelopment of the Rice Yards Site will occur in phases over the next approximately 20-25 years. During its assessment of the Site for redevelopment, KRS discovered contamination it alleged was from the MGP. As a result, in 2019, KRS asserted statutory, contractual, and common law claims against Public Service for cost recovery of its environmental investigation and remediation costs for the Rice Yards Site.

Q. IS KRS PERFORMING THE REMEDIATION OF THE SITE?

A. Yes. On or about May 28, 2019, KRS entered into a First Amendment to Consent Agreement No. 92-08-31-01 with the Colorado Department of Public Health and Environment ("CDPHE") for the investigation and remediation of the Rice Yards Site. The First Amendment to Consent Agreement is publicly available from CDPHE and required that KRS complete additional investigations of the property and prepare a Site Characterization Report, which it completed in 2020. KRS will

[26] "KRS" refers to KSE Elitch Gardens / Revesco / Second City, LLP.

remediate the Rice Yards Site during its redevelopment work, pursuant to a CDPHE approved materials management plan and Corrective Action Plan.

Q. DID THE COMPANY REACH A SETTLEMENT AGREEMENT WITH KRS FOR ITS INVESTIGATION AND REMEDIATION COSTS FOR THE RICE YARDS SITE?

A. Yes. The Company reached a final confidential settlement agreement with KRS in 2020 to resolve all of its claims fully. [redacted]

[redacted]

Q. HAS THE COMPANY RECENTLY PURSUED RECOVERY OF ANY OF THE DENVER OR KRS SETTLEMENT COSTS FROM ITS HISTORICAL INSURERS?

A. Yes. As reported to Staff and UCA in semi-annual updates, agreed upon in a prior proceeding, we participated in a mediation process and ultimately the parties agreed with the mediator's recommendation to settle the insurance litigation for [redacted]. This is a good settlement. Typically, the Company can only recover a portion of our remediation costs from our historical insurance policies in part because damages are limited to pre-1980 releases due to pollution exclusions that were added to all commercial general liability insurance policies in the 1980's. Colorado is also a state where damages are allocated across multiple insurance policies on a pro rata basis (and self-insured retentions or deductibles must be met before insurance coverage can be triggered). These types of claims are also difficult to litigate and highly dependent on expert opinions given that site operations commenced over 100 years ago and the parties will argue over when and how releases to the environment historically occurred. The [redacted] received was used to offset any ongoing costs of the investigation, remediation, and litigation over the Rice Yards Site and that credit has resulted in the small negative regulatory liability deferral balance included in this case.

Q. HAS THE COMMISSION PREVIOUSLY AUTHORIZED RECOVERY OF THE COMPANY'S MGP COSTS?

A. Yes. The Commission has previously authorized the Company to recover the costs incurred for the investigation, remediation, and defense of MGP sites, including the Boulder MGP Site, another former MGP site in Fort Collins and, most recently, the Denver Sites.[27]

Q. PLEASE DESCRIBE THE COMMISSION'S AUTHORIZATION FOR DEFERRAL AND RECOVERY OF MGP COSTS FOR THE DENVER SITES.

A. On June 27, 2017, Public Service filed an application in Proceeding No. 17A-0435G for approval of deferred accounting treatment for all expenditures related to investigating, litigating responsibility for, and remediating possible environmental contamination at, or originating from, the Rice Yards Site and/or the Crown Tar Works Site. Through Decision No. R17-0705 (the "Rice Yards/Crown Tar Works Order"), the application for deferred accounting, as amended, was granted and Public Service was authorized to create a regulatory asset and to use deferred accounting treatment for those costs. In connection with the application and authorization to use deferred accounting, Public Service agreed to provide semi-annual updates to Staff regarding developments and costs being incurred under the Rice Yards/Crown Tar Works Order. As a courtesy, the Company has also provided these confidential updates to the UCA.

---

[27] Public Service previously received authority to recover and amortize net MGP costs in prior rate cases, in Proceeding Nos. 12AL-1268G, 15AL-0135G, 17AL-0363G, 20AL-0049G, and 22AL-0046G.

Q. DID THE COMMISSION AUTHORIZE RECOVERY OF SOME DEFERRED MGP COSTS FOR THE DENVER SITES IN THE 2022 GAS RATE CASE?

A. Yes. The Commission approved recovery of $7,525,503 of deferred MGP costs associated with the Denver Sites in the 2022 Combined Gas Rate Case, and such amounts were included in the 18-month amortization approved in that case.[28]

Q. IS THE COMPANY SEEKING TO RECOVER AND AMORTIZE ADDITIONAL MGP COSTS RELATING TO THE DENVER SITES IN THIS CASE?

A. No; the Company expects that after the completion of the amortization approved in the 2022 Combined Gas Rate Case there will be a regulatory liability balance associated with the MGP plants of $403,013. As a result, the Company is not proposing a new amortization of this amount but instead to maintain that regulatory liability on its balance sheet to apply against future cost deferrals associated with the MGP site.

Q. WHY IS THERE A REGULATORY LIABILITY BALANCE ASSOCIATED WITH THE MGP DEFERRAL?

A. As noted above, the Company received an insurance settlement payment of [redacted] in August 2023 that was in part offset by accrued liability of [redacted] of which [redacted] is for a settlement milestone payment due to KRS most likely [redacted] in late 2024) and [redacted] in 2025) and [redacted] is for

[28] Decision No. R20-0672 in Proceeding No. 20AL-0049G, at ¶ 119 and Appendix A, p. 14. The Commission also authorized $3,007,040 of deferred Boulder MGP costs in the 2020 Combined Gas Rate Case, and such amounts were included in the 36-month amortization put into place as part of that case relative to the Boulder Sites. *Id.* Since then, there have been no additional deferred Boulder MGP costs and no additional insurance proceeds have been received. Mr. Freitas further discusses the unamortized MGP deferred balances for Boulder and the Denver Sites in his Direct Testimony.

environmental remediation expenses that will be incurred. The net credit of [redacted] that is the difference between those two amounts coupled with an expense of $146,987 results in the forecasted regulatory liability of $403,013 once the past amortization is complete. The Table below summarizes this calculation:

Table JJP-D-1
Current Deferred Balance for Denver Sites

Category	*Amount*
[redacted]	[redacted]
[redacted]	[redacted]
Legal/consulting fees incurred since last rate case	$146,987
Total Regulatory Asset/(Liability) Balance:	**($403,013)**

The MGP costs are reasonable and necessary expenses that the Company has incurred in the course of its provision of utility service. I am not an attorney, but it is my understanding that environmental laws and regulations require Public Service to investigate and clean-up contaminated MGP sites that the Company previously owned or operated (and areas that may now be impacted by pollution from the MGP sites), and there are now contractual obligations for supporting such work under the settlement agreement. The costs of resolving these environmental claims are necessary and unavoidable costs of doing business.

Q. WILL THE COMPANY CONTINUE TO MAINTAIN A REGULATORY ASSET (OR LIABILITY) FOR THE DENVER SITES?

A. Yes. The Rice Yards/Crown Tar Works Order provides for deferred accounting treatment for all expenditures related to investigating, litigating responsibility for, and remediating possible environmental contamination at, or originating from, the

Rice Yards and Crown Tar Works Sites. The Company will continue to maintain a regulatory asset and continue to defer costs and recoveries associated with environmental contamination at or originating from the Sites. Any additional deferred costs and recoveries will be brought forward for recovery in a future proceeding.

6. Information Technology ("IT") Cost Deferral

Q. WHAT TOPIC DO YOU COVER IN THIS SUBSECTION OF YOUR DIRECT TESTIMONY?

A. I support the Company's request for deferred accounting for certain IT capital investments placed in service after the Test Year in this Proceeding ("IT Cost Deferral").

Q. WHAT COSTS DOES THE COMPANY REQUEST BE DEFERRED FOR POSSIBLE RECOVERY IN A FUTURE RATE CASE?

A. The IT Cost Deferral would apply to Aging Technology and Cybersecurity capital costs discussed in detail by Company witness Ms. Megan N. Scheller in her Direct Testimony.

Q. PLEASE BRIEFLY EXPLAIN WHY THESE COSTS SHOULD BE DEFERRED IN A TRACKER.

A. As discussed by Ms. Scheller, these assets have relatively short depreciable lives. As a result, the effects of regulatory lag have an outsized impact as compared to other assets with longer depreciable lives. This impact is becoming especially acute as information technology becomes a larger part of the Company's business given new IT standards, evolving risks, and ever-growing data needs. These cost recovery challenges may result in sub-optimal deployment (and resulting decreased productivity, increased security risk, or both) or more frequent rate proceedings, neither of which should be viewed as emblematic of effective utility regulation. Ms. Scheller and Mr. Freitas further explain why a tracker alleviates the risk of recovery for these shortened asset lives.

These costs also share some characteristics with other costs that have been recognized historically as being appropriate for deferral. For example, one reason supporting the establishment (and continuation) of the property tax expense tracker and damage prevention program tracker is that the Company has virtually no control over the amount of property taxes assessed by various taxing jurisdictions or utility locates demanded by customers and contractors. Similarly, as discussed by Ms. Scheller, the Company does not have control over new technology standards, nor the pace at which cybersecurity threats are emerging. Further, Ms. Scheller explains that the Company has limited choices when it comes to replacing aging systems that are no longer supported by the vendor, able to be updated due to lack of parts or technology changes, or otherwise out-of-date for utility use. Our systems need to meet increasingly demanding data security, reliability, and compliance requirements. The Company must also respond to cybersecurity threats to comply with legal and regulatory requirements, and risk management objectives. Further, given the unpredictability of these threats, it is important that these tools and resources continue to change in response to new threats to our information systems.

Q. HOW WOULD THE TRACKER WORK?

A. First, the Commission would authorize deferral of incremental Aging Technology and Cybersecurity costs, commencing January 1, 2024, at the end of the proposed Test Year, for potential recovery in future cases. As Aging Technology and Cybersecurity projects are placed in service, the Company would begin to defer depreciation expense associated with the plant in service balance, as well as interest on that balance, calculated at the Company’s WACC. Then, in the Company’s next Phase I rate case, the Company would seek recovery of the deferred amounts. In that rate case, the Company would propose to amortize the deferred depreciation and associated return over a certain period of time.

Q. WHY SHOULD THE INTEREST ON THE PLANT IN SERVICE BALANCE BE CALCULATED AT THE COMPANY’S WACC?

A. The Company will incur actual capital costs for the Aging Technology and Cybersecurity projects subject to the deferral. Those costs will be financed through both equity and debt, just like other components of rate base. Yet the Company will not actually recover those costs until some future period. Authorizing a WACC return on Aging Technology and Cybersecurity projects placed in service recognizes the true cost of financing those projects.

V. GAS STORAGE INVENTORY COSTS

Q. WHAT TOPIC DO YOU COVER IN THIS SUBSECTION OF YOUR TESTIMONY?

A. In this section, I discuss the Gas Storage Inventory Cost ("GSIC") and recommend that the Commission reverse its determination made in the Company's last gas rate case and provide a return at the Company's WACC on the GSIC included as a component in the GCA. While the GSIC is not an item that affects the Company's base rates, it was discussed in the last rate case, and the Company seeks to revisit the topic to explain in more detail how the Company finances its gas storages reserves with both debt and equity, and why a WACC return is appropriate despite how gas reserves are a short-term asset that are added and withdrawn throughout a given year.[29] Attachment JJP-3 includes the Company's proposed tariff modifications to reflect a return based on WACC rather than short-term debt.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE GSIC AND WHY IT IS INCLUDED AS PART OF ITS GCA.

A. The GSIC reflects the revenue requirement associated with the Company's investments in gas storage reserves. This revenue requirement is calculated by multiplying the authorized return by the average monthly cost of the Company's gas storage inventory and adjusting for income taxes.

[29] The Company notes that the UCA has also initiated a formal complaint at the Commission regarding the Company's inclusion of a federal and state income tax gross-up to the short-term debt-only interest rate and the specific short-term debt rate used as part of the GSIC calculations included in the GCA (see Proceeding No. 23F-0611G). The Company maintains that these are separate issues from those discussed in this section of my testimony, and the litigation of that separate complaint case should have no impact on this proposal..

Up until 2011, this cost was recovered through base rates. However, in 2010 the Commission approved a settlement agreement between the Company and Staff, via a complaint proceeding, that called for the Company to move the GSIC over from base rates and into a rider to be implemented in the next rate case. This was the result of both the Company and Staff recognizing that while the Company's average cost of gas storage inventory included in base rates was fixed between rate cases, the actual inventory balance could fluctuate significantly from year to year due to fluctuations in gas commodity prices. Consequently, the Company's earnings in relation to its actual costs could (and did) also fluctuate significantly depending on changes to commodity prices. As a result, recovering these costs through a rider rather than through base rates could provide more timely adjustments to the changes in commodity prices and thus the value of gas storage inventories. This would better protect customers when commodity prices fall and the value of gas storage reserves was on average lower compared to previous years, resulting in reductions to the GSIC, and would better protect the Company when gas prices rise. Beginning in 2011, after the conclusion of the subsequent gas rate case, the Commission approved the shift of the GSIC from base rates over to the GCA, where it has remained ever since.

Q. PLEASE SUMMARIZE THE COMMISSION'S MOST RECENT RATE CASE DECISION ON THIS TOPIC.

A. In the last gas rate case, Staff contended that the GSIC is a temporary and volatile short-term asset and, thus, should receive a carrying charge commensurate with the Company's short-term financing rate rather than WACC. The Commission ultimately agreed that the return on gas storage inventories should be at a lower level due to "the temporary and volatile nature of the asset" and that it "has significantly modified its approach to setting returns on items included in a utility's rate base since the 2012 gas rate case."[30]

Q. WHY DOES THE COMPANY RECOMMEND THE COMMISSION REVISIT THIS DETERMINATION?

A. The Company respectfully requests that the Commission reevaluate the return allowed for gas storage inventory costs for several reasons. The first is policy-based, in light of the Company's, the Commission's, Colorado lawmakers', and customers' more acute interests in service reliability and rate stability in light of extraordinary storms and gas prices witnessed in recent years. With ongoing focus on the Company's gas purchasing strategies, the need to reduce fuel cost volatility, and the development of new fuel cost incentive mechanisms, the use of gas storage is a vital component to the arsenal of tools that the Company can rely on to pursue both reliable service and reduce its exposure to daily and monthly price fluctuations in gas markets. Providing a return on gas storage inventories that is below the actual cost of financing those assets, however short-term in nature they may be, ultimately provides a financial disincentive to developing and relying on those assets fully.

Furthermore, the important characteristic of fuel inventories is the amount of inventory that needs to be present in a given period of time in order to safely

[30] Proceeding No. 22AL-0046G, Decision No. C22-0642, at ¶ 381.

and reliably operate the Company's gas and electric systems – not the amount of time that actual fuel deliveries are present, either in reserve or onsite. Singling out fuel inventories for lower returns has no basis in reality, as the Company has a variety of assets that are both shorter-term and longer-term but which are all financed from the same sources. This is why there is already a mix of long-term debt, short-term debt, and equity in the Company's overall capital structure.

As I discuss more below, the Company finances all of its assets (in rate base and otherwise) with the same mix of internally generated funds and a balance of debt and equity (as reflected in the Company's capital structure). Therefore, a debt-only return, not to mention a short-term debt-only return, is notably less than the weighted average cost of capital that stems from the Company's actual capital structure, actual long-term cost of debt, and cost of equity as all determined in rate cases. Therefore, it deprives the Company of a fair return on assets maintained to serve customers.

Q. PLEASE DISCUSS THE 2012 RATE CASE THAT THE COMMISSION MENTIONED WHEN AUTHORIZING A LOWER RETURN ON GAS STORAGE INVENTORIES IN THE COMPANY'S PREVIOUS RATE CASE, AND A BROADER HISTORY OF THE COMMISSION'S DETERMINATIONS ON THIS TOPIC.

A. As quoted above, the Commission stated in the Company's last rate case that it has "modified its approach to setting returns on items included in a utility's rate base" in recent years, apparently referring to the Commission decision in the 2012 proceeding and maintained until recently. However, the decision to authorize a short-term debt only return on gas storage inventories represented a shift in the treatment of those inventories, regardless of whether those costs were historically part of base rates or quarterly GCAs. Notably, the Commission's decision in the 2012 proceeding was thorough and the fundamental facts regarding the nature of the asset and the funding, both of which are aligned with how the Company manages these costs today.

In particular, in Proceeding No. 12AL-1268G, regarding the Company's GSIC, the Commission stated that:

> We agree with the ALJ's conclusion that the GSIC should be considered a rate base asset as prescribed in FERC accounting rules and that GSIC should be treated no differently than any other asset with respect to the determination of a return. We also agree with Public Service that, while storage gas is classified as a short-term asset, different types of financing including long-term bonds and equity are used to cover the associated costs.[31]

The Company calls attention to this determination because it reflects the same logic that the Company supports in this proceeding. Until the 2022 Combined Gas Rate Case, as far as I am aware, the Company's GSIC was always awarded a return commensurate with the authorized WACC. While regulatory structures and matters can and do change over time in order to pursue new or different policy objectives, the Company does not consider the historically-authorized return on the GSIC to be a topic that is out of alignment with the current policy landscape. Ultimately, the Company must maintain balances – though they may be variable – to serve customers. Critically, the variability of the balances themselves does not

[31] Proceeding No. 12AL-1268G, Decision No. C13-1568 ¶ 86 .

change how the asset is funded, and the Company's GSIC should be afforded a WACC return. Therefore, the Commission's decision in the 2022 gas rate case created a disconnect between the allowed return on the asset and the underlying principle that a utility is entitled to a full return on assets deployed to serve customers. The variability of the asset may affect the total dollar amount of the return at any given time – which is why these assets are appropriate in the GCA, where variability is better managed than through base rates – but it should not change the rate of return on the asset.

In addition, as stated previously, a return on the GSIC that is below the Company's actual financing costs provides an (likely) unintended <u>disincentive</u> to utilize gas storage reserves fully. If the Company must invest in those assets without obtaining a full return on the investment, it is not reasonable to also expect the utility's shareholders to maximize the amount of that investment.

Q. PLEASE PROVIDE AN OVERVIEW OF GAS STORAGE INVENTORIES IN RECENT YEARS.

A. Table JJP-D-2 below provides annual balances for gas storage inventories over the 2020-2023 period, showing the average balance in a particular year.

TABLE JJP-D-2:
Gas Storage Inventories, 2020-2023

	2021	2022	2023
Dekatherms			
[redacted]			

As shown above, the Company has an ongoing financing need of at least [redacted] a month for each year over the past three years, and an average monthly financing need of at least [redacted] a month over the past three years. As discussed previously, while these balances swing significantly within a particular year, the Company clearly has an ongoing and long-term need to finance notable gas inventory costs across years and the Company must rely on its overarching financing options, which finance all Company operations, to fund these ongoing balances.

Q. DO OTHER SIMILAR ASSETS RECEIVE A FULL WACC RETURN?

A. Yes. Similar to gas storage inventories, the Company's fuel inventories on the electric side of the business and materials and supplies inventories in both the gas and electric utilities are included as part of rate base and receive a full return at the most recently authorized WACC. These inventories largely refer to the coal piles onsite as coal-fired power plants and fuel oil in storage tanks at other power plants with dual fuel capabilities (*i.e.*, natural gas and fuel oil). The materials and supplies inventories represent the cost of equipment that is purchased but held in inventory so that the Company has the necessary materials on hand to be able to reliably operate and maintain the gas and electric systems and to provide safe, adequate, and reliable service to our customers. These are service-producing assets, like gas storage inventories, and are therefore entitled to a WACC return.

Q. PLEASE DISCUSS IN MORE DETAIL HOW THE COMPANY FINANCES FUEL INVENTORIES.

A. Like all assets, the Company finances them with a mixture of internally generated funds, debt (including short-term debt and longer-term bonds), and equity.

Q. DOES THE ADDITION OF SHORT-TERM DEBT IN THE COMPANY'S AUTHORIZED CAPITAL STRUCTURE LOGICALLY LEAD TO A SHORT-TERM DEBT-ONLY RETURN FOR SHORTER-TERM ASSETS?

A. No. The Company does not issue short-term debt, longer-term bonds, or equity in order to finance specific projects, actions, or assets. Rather, financing tools are used to fund the entirety of the Company's investments. Short-term debt was added to the Company's authorized capital structure in recent years and reflects the Company's reliance on credit facilities and money pools as a component of its external financing needs. Given that the Company finances fuel inventories in the same way as other assets, authorizing a short-term debt only return for them is a non-sequitur from the fact that the Company has been and continues to rely on short-term debt as a part of its ongoing financing needs, whether or not short-term debt is an actual component of the authorized capital structure.

In fact, a short-term debt only return for certain assets double counts the use of short-term debt as part of the capital structure. Customers already benefit from the Company's use of short-term debt, both in its operations and in the authorized capital structure. Authorizing a short-term debt only return on GSIC amounts has the effect of ignoring the long-term debt and equity components of the capital structure and focusing solely on short-term debt when it is already accounted for the Company's authorized capital structure. In effect, it is a disallowance on the actual costs the Company incurs to finance these investments – but without any reasonable basis. This reduces the ability of the Company to have a reasonable opportunity to earn a return commensurate with its the authorized return.

Q. ARE THERE OTHER, MORE RECENT COMMISSION DECISIONS THAT FURTHER SUPPORT A WACC RETURN ON GSIC?

A. Yes. In the Company's 2019 electric rate case, Staff argued that the Company should include short-term debt in its capital structure, in part on the ground that "all funding sources contribute to all investments, and therefore should not be excluded."[32] The Commission agreed with Staff that "money is fungible," and concluded that all sources of debt contribute to funding Company investments.[33] The same conclusion remains true today, and underscores that whether an asset is large or small, variable or not, all sources of capital fund that investment. This

[32] Proceeding No. 19AL-0268E, Decision No. C20-0096E at ¶ 113.
[33] Proceeding No. 19AL-0268E, Decision No. C20-0096E at ¶ 119.

is why it is important to apply the WACC – including a mix of equity, long-term debt, and short-term debt – to the GSIC.

Q. WHAT IS THE IMPACT FROM APPLYING A SHORT-TERM DEBT ONLY RETURN ON GSIC AMOUNTS VERSUS A WACC RETURN?

A. Applying a short-term debt return rather than a WACC return equates to about a $383,000 impact to the Company given the discrepancy between current short-term debt rates and the cost of all capital. Importantly, the financial impact increases notably when using the short-term debt rate authorized in the Company's most recent rate case. Given that interest rates have changed in recent years in light of Federal Reserve actions, the discrepancy between the Company's authorized short-term debt rate and actual short-term debt rates has grown.

VI. RATE CASE EXPENSES

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S RATE CASE EXPENSE REQUEST.

A. The Company is seeking to recover outside legal, consulting, customer noticing, hearing, and other miscellaneous costs associated with this case. We also request to amortize these expenses over a 36-month amortization period, which is longer than our proposed amortization period for the deferred assets described above. The Company proposes this disparate treatment for rate case expenses, compared to the other proposed amortizations, to align with the Commission's direction in the last gas rate case, which authorized a 36-month amortization period,[34] to reduce the number of contested items in this proceeding, and in recognition that rate case expenses and their recoverability will be further addressed in a future rulemaking per the directives in SB 23-291.[35] The Company proposes to earn a return on the unamortized balance at the Company's WACC, as explained by Mr. Freitas in his Direct Testimony.

Q. ARE RATE CASE EXPENSES A NECESSARY AND RECOVERABLE ITEM IN THE COST OF SERVICE?

A. Yes. As discussed in Commission Decision No. R21-0400 in Proceeding No. 20AL-0432E:

> The Colorado Supreme Court recognized over four decades ago that the Commission 'has always allowed' regulated utilities to recover 'as a proper operating expense attorneys' fees and legal costs

[34] *See* Decision No. C22-0642, ¶ 174.
[35] Section 2 of SB 23-291 (codified at § 40-3-102.5(1)(a), C.R.S.).

> incurred' in their rate cases litigated before the Commission. Indeed, the [Court found the] 'recovery of rate case expenses to be a normal and legitimate activity for a regulated utility.' The Commission has often found that rate case expenses are a legitimate cost of providing utility service, necessitated by Commission regulation of the utility, and that Colorado regulated utilities, including Public Service, have a right to seek recovery through rates for all reasonable operating expenses, including rate case expenses.[36]

Q. WHY ARE RATE CASE EXPENSES A PROPER OPERATING EXPENSE?

A. Most businesses have the flexibility to set their prices based on an assessment of the market and demand for their products. The Company, however, as a regulated utility, does not have that option available to it. Rather, it is necessary for the Company to file a rate case, such as the instant proceeding, in order to modify its cost of service and rate schedules. Indeed, rate-regulated utilities could not meet their obligation as public utilities to provide safe, adequate, and reliable service absent rate cases, filed when needed, to recover reasonable costs of providing that service, along with a reasonable return to attract capital that likewise serves customers. As a consequence, the Commission has recognized that rate cases are a normal and necessary activity for utilities, and that the costs of rate cases are a necessary part of operating as a public utility with an obligation to serve.

---

[36] Decision No. R21-0400 in Proceeding No. 20AL-0432E at ¶ 151 (internal quotes, footnotes and citations omitted). Decision No. R21-0400 became the decision of the Commission pursuant to Decision No. C21-0536 except as amended by Decision No. C21-0536. This portion of Decision No. R21-0400 was not amended and became the decision of the Commission. *See* Decision No. C21-0536, Ordering Paragraph No.1 at page 38.

Q. HAS THE COLORADO LEGISLATURE RECENTLY ADOPTED LEGISLATION THAT MAY AFFECT RATE CASE EXPENSES?

A. Yes. As I discuss in more detail later in my testimony, the Colorado legislature recently adopted SB 23-291, which affects aspects of utility cost recovery in rate case proceedings and other matters. Among the provisions of SB 23-291 is Section 40-3-102.5(1)(a) of the Colorado Revised Statutes ("C.R.S."), which states: "The Commission shall establish rules to limit the amount of rate case expenses that a utility may recover from ratepayers." The Company expects that the Commission will initiate this rulemaking soon to implement this provision of the statute.

Q. DOES THE UPCOMING RULEMAKING AFFECT THIS CURRENT CASE?

A. No, the rules contemplated by § 40-3-102.5(1)(a), C.R.S., have not yet been proposed or adopted. However, we recognize the policy interest in limiting or controlling the amount of rate case expenses, and that in past rate cases the Commission has likewise encouraged the Company to better manage the amount of its rate case expenses.

Q. IS PUBLIC SERVICE ABLE TO AVOID RATE CASE EXPENSES?

A. No. It is neither possible nor prudent for the Company to attempt to avoid incurring rate cases altogether. Even with the new legislation, the Company still must file rate cases as its primary means of cost recovery, and incur certain costs to meet statutory and Commission requirements for such cases. Some of those requirements have existed for some time, including the need to publish notices, pay for hearing costs, and obtain legal support for those cases beyond the capacity of the Company's in-house resources. Some requirements are new and heightened, as SB 23-291 also includes a series of new prerequisites for the utility to meet even before the contested case proceeding gets underway. Additionally, many aspects of the rate case process are outside the utility's control, such as the number of intervenors and issues raised in the case, the quantity of discovery, disputes over discovery responses, and additional filing requirements of the Commission. As such, there is tension between increasing rate case requirements and costs and the Commission and legislature's understandable goals of containing rate case expenses to the extent reasonably possible.

Q. IS PUBLIC SERVICE NONETHELESS DEMONSTRATING A CONCERTED EFFORT TO CONTAIN RATE CASE EXPENSE, AND ITS REQUESTED RECOVERY OF SUCH EXPENSES, IN THIS CASE?

A. Yes. Despite heightened requirements and the Company's need to support its requests in any rate case, Public Service has sought to contain its rate case expenses below the levels approved in recent Combined and Phase I cases. Specifically, the total rate case expenses associated with this Phase I proceeding are estimated to be $1,577,518, assuming a fully litigated case with a hearing, post-hearing briefing, and applications for rehearing, reargument, and reconsideration. Table JJP-D-3 summarizes the estimated expenses for this proceeding by category.

Table JJP-D-3:
Phase I Rate Case Expenses by Category

Category	Expense Estimates
Legal Counsel	$1,235,000
Consulting	$260,000
Customer Noticing	$42,600
Hearing Costs	$23,063
Miscellaneous Expenses	$16,855
Total Rate Case Expenses	**$1,577,518**

Q. ARE MOST OF THESE RATE CASE EXPENSES FROM OUTSIDE VENDORS?

A. Yes. The majority of the Company's rate case expenses relate to work done by outside vendors, such as law firms and expert consultants. In this proceeding, the Company has engaged Taft Stettinius & Hollister LLP, Wilkinson Barker Knauer LLP, Ms. Ann E. Bulkley of The Brattle Group, and Mr. Ronald J. Amen of Atrium Economics to assist with the presentation of the Company's case.

Q. HAS THE COMPANY WORKED WITH THESE LAW FIRMS AND EXPERT CONSULTANTS ON PREVIOUS CASES?

A. Each of the outside law firms and Ms. Bulkley have worked with the Company on its prior rate cases and in a variety of other matters before the Commission. To my knowledge, the Company has not worked with Mr. Amen in prior cases.

Q. DOES WORKING WITH LAW FIRMS AND EXPERT CONSULTANTS THAT HAVE PRIOR EXPERIENCE WITH THE COMPANY HELP CONTROL COSTS?

A. Yes. Using vendors with whom the Company has an established working relationship translates into cost efficiencies because those vendors already have a good understanding of the Company, its processes, personnel, the Commission, and the litigation of rate cases here. The law firms involved in this case and Ms.

Bulkley all possess institutional knowledge and experience with Public Service that reduces the amount of time those attorneys and consultant must spend acquainting themselves with the Company, its practices, the Commission's past requirements and preferences, and Colorado ratemaking generally.

Q. DID THE COMPANY RELY ON ANY COMPETITIVE PROCESSES FOR PROCURING THE SERVICES OF THESE OUTSIDE FIRMS?

A. Yes. The Company asked for and received proposals for outside legal services from several law firms and ultimately selected the firms listed previously. The Company considered a range of factors and used its reasoned judgment to make an appropriate decision under the circumstances, including factors such as cost, knowledge of the Company and the likely issues, resource availability, knowledge of the Colorado regulatory environment in past cases, and general expertise. The Company then worked with outside counsel to identify and contract with other outside witnesses in this case, including Ms. Bulkley and Mr. Amen.

Q. DOES THIS APPROACH HELP CONTROL COSTS IN OTHER WAYS?

A. Yes. The firms and consultants we have partnered with bring very specific knowledge, expertise, and skill sets to our cases. They are rate case experts, with valuable areas of expertise, and the majority are familiar with Colorado proceedings. More broadly, the retained consultants possess subject matter expertise that will provide both the Commission and interested stakeholders with a broader perspective on the issues they support. All of this is critical to the effective and efficient processing of rate case proceedings, as well as effectively controlling rate case expenses.

Q. ARE THERE ALSO INSTANCES WHEN IT IS APPROPRIATE TO BRING IN A NEW CONSULTANT OR SUPPORT PROFESSIONAL?

A. Yes. In most aspects of developing its case, the Company must use reasoned judgment to select outside resources that are properly aligned with the needs of the case at hand. At times, as with the Company's revenue stability mechanism ("RSM") proposal in this case, it is helpful to both the Company, other parties, and the Commission to bring in a consultant with a new perspective and broad range of knowledge and experience on the issue presented. In this case, the Company brought in Atrium Consulting to help shed light on a complex topic that is being addressed in various jurisdictions across the United States, and to support the RSM proposal in this case.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE SPECIFIC COSTS IN THIS CASE?

A. Yes. Below I walk through each category of rate case expense and provide additional detailed support for the Company's costs.

A. <u>Rate Case Expense Categories</u>

Q. WHAT ARE THE DIFFERENT CATEGORIES OF RATE CASE EXPENSES?

A. The Company categorizes rate case expense as follows: (1) legal counsel; (2) consulting; (3) customer noticing; (4) hearing costs; and (5) overhead costs. I discuss each of these categories below. In addition, Attachment JJP-1 provides a more detailed summary of rate case expense by major category.

1. Legal Counsel

Q. WHAT COSTS ARE INCLUDED IN THE LEGAL COUNSEL CATEGORY?

A. The legal counsel category consists of estimated fees of the outside legal resources retained by the Company to assist with this Proceeding.

Q. WHAT LAW FIRMS WILL PROVIDE THESE OUTSIDE LEGAL SERVICES?

A. As mentioned above, the Company retained two law firms to assist with this Proceeding: Taft Stettinius & Hollister LLP and Wilkinson Barker Knauer LLP.

Q. HAS THE COMPANY TAKEN STEPS TO CONTAIN LEGAL EXPENSES FOR THIS RATE CASE, AND WILL IT CONTINUE TO DO SO DURING THE COURSE OF THIS CASE?

A. Yes. Although the Company does not necessarily believe a request for proposal should be necessary for the retention of legal services when particular expertise and experience is needed, in this instance Public Service issued a competitive solicitation. Additionally, the Company has taken steps to simplify this rate case overall, including by selecting a 2023 calendar year test year, in an effort to contain rate case costs.

Q. WHY DID THE COMPANY RETAIN THESE SPECIFIC FIRMS?

A. Each of these firms was retained for its rate case expertise, specific knowledge of Public Service and other Xcel Energy operating companies, experience with prior Colorado rate case proceedings, and familiarity with other proceedings in front of this Commission.

Q. WHAT FACTORS DOES THE COMPANY CONSIDER WHEN ASSESSING OUTSIDE LEGAL COUNSEL?

A. The Company considers a variety of factors, including the firm's or attorneys' skill and experience, whether proposed rates are consistent with the market for the particular type of work involved, the Company's past experience with particular attorneys or firms (the Company typically uses attorneys with whom it has a continuing relationship to ensure the attorneys' familiarity with our business), and the ability of an attorney or firm to meet the time demands of a proceeding. Ultimately, the Company selected experienced regulatory counsel who have appeared before the Commission.

Q. WHAT LEGAL SERVICES WILL THESE FIRMS PROVIDE?

A. The firms have provided, or will provide, assistance in preparing the filings in this case, inclusive of testimony and attachments, as well as with regard to witness preparation, advice on strategy, responding to discovery, and generally processing the case.

Q. ARE INTERNAL ATTORNEYS WORKING ON THIS PROCEEDING?

A. Yes. The Company's internal attorneys manage outside legal resources and are integrally involved in all aspects of the case, providing significant legal services in addition to those provided by outside legal counsel.

Q. DO THE COMPANY'S ATTORNEYS WORK TO MAKE SURE THERE IS NOT DUPLICATION OF EFFORTS?

A. Yes. The Company's internal legal team works hard to ensure that duties are appropriately assigned to outside legal counsel and to ensure that work efforts are not duplicative. The internal and external legal teams work as a unit and are in constant coordination to be as efficient as possible.

Q. COULD THE COMPANY USE ONLY INTERNAL ATTORNEYS FOR ITS RATE CASES?

A. No. The Company's internal legal department supports all the Company's regulatory matters before the Commission. In 2023 alone, we had 127[37] separate proceedings filed before the Commission. That does not account for proceedings from prior years that carried into 2023. While our internal regulatory legal team does a significant amount of work to support our rate case proceedings, they must handle a significant caseload of other regulatory matters before the Commission in addition to fulfilling other responsibilities. Therefore, we still need to utilize outside legal resources for certain regulatory proceedings.

Further, rate cases are among the most significant proceedings we have before the Commission and surely are among the most complex. Our outside legal partners bring rate case expertise that helps in the development of a comprehensive factual record and ultimately contributes efficiencies to the process.

[37] As of November 5, 2021.

2. Consulting

Q. WHAT COSTS ARE INCLUDED IN THE CONSULTING CATEGORY?

A. The consulting category consists of costs associated with securing outside consultants or witnesses with specific areas of expertise that are necessary for the support and completion of the case. In this Proceeding, the consulting costs are those associated with expert testimony being provided by Ms. Bulkley of The Brattle Group as related to Return on Equity ("ROE") and related issues, and Mr. Ron Amen of Atrium Economics for decoupling. Ms. Bulkley provides independent testimony on market considerations and inflation risk that supports the reasonableness of the Company's proposal. Mr. Amen provides independent testimony with additional perspective on decoupling for gas utilities, and he supports the Company's RSM proposal in this case.

Q. HAS THE COMPANY WORKED WITH MS. BULKLEY IN THE PAST?

A. Yes. Public Service has worked with Ms. Bulkley in prior Commission proceedings or in connection with prior engagements. For example, Ms. Bulkley was the Company's ROE witness in its last two gas rate cases (Proceeding Nos. 22AL-0046G and 20AL-0049G). She was also the Company's ROE witness in recent electric Phase I rate cases.

Q. DOES THE COMPANY EXPERIENCE SAVINGS AS A RESULT OF ITS PRIOR EXPERIENCE WITH MS. BULKLEY?

A. Yes. Ms. Bulkley is familiar with the Company and Colorado regulatory proceedings, allowing her to efficiently produce materials that contribute to the development of a sound evidentiary record. Ms. Bulkley's history of working with the Company allows her to work efficiently and collaboratively with Company contacts, which has resulted in actual expenses being below initial estimates in some past proceedings. These efficiencies cannot be achieved with an unfamiliar witness, even if they have the same areas of expertise.

Q. WHY DOES THE COMPANY RETAIN OUTSIDE CONSULTANTS TO DEVELOP ROE TESTIMONY?

A. ROE and capital structure are critical issues in all Phase I proceedings. The witness developing the ROE recommendation must be experienced and must be able to explain the analysis clearly. We do not maintain the in-house expertise required of an ROE witness. Consequently, we must hire a consultant to provide the analysis and testimony. The Company does not hire an internal employee with this area of expertise to fulfill that responsibility because it is a very specialized field. Moreover, external experts generally have a broader view of developments in their areas of expertise than internal employees focused on the eight states in which Xcel Energy operates and are independent in that they are not Company employees and provide an outside perspective.

Q. PLEASE EXPLAIN WHY THE COMPANY HIRED AN OUTSIDE WITNESS TO ADDRESS DECOUPLING MATTERS.

A. The Company thought it would be valuable to the Commission and all interested parties to hear from experts that work on the topic of decoupling across the country. This expertise 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 others, and how a specific design could work for the Company's gas business. Furthermore, Mr. Amen has decades of experience working with regulated utilities and state commissions across the U.S. and Canada on rate regulation, rate design, planning, and pricing topics, among others, which can help provide valuable context on rate reform topics in Colorado.

3. Customer Noticing, Hearing, and Overhead Costs

Q. DO THE COMMISSION'S RULES INCLUDE NOTICE REQUIREMENTS FOR RATE CASES?

A. Yes. Rule 1210 of the Rules of Practice and Procedure requires the Company to notify customers regarding this rate request. Historically, this meant sending out a mailing to all customers at a substantial cost. More recently, the Company has utilized an alternative form of notice ("AFN") that includes legal notices, bill onserts, emails, and posting to our Company website. We are proposing to use that same alternative procedure here.

Q. WHAT COSTS ARE INCURRED FOR CUSTOMER NOTICING?

A. There are three costs: (1) bill onsert; (2) newspaper noticing; and (3) translation to Spanish. The bill onsert component is the cost associated with printing the notice on customers' bills and mailing it to customers during their normal billing cycles. The newspaper component consists of posting the notice of our filing in a newspaper of general circulation for two consecutive weeks. There is also a cost for translating the notice and bill onsert to Spanish to post on the Company's website.

Q. PLEASE DESCRIBE THE HEARING TRANSCRIPTS COMPONENT OF RATE CASE EXPENSE.

A. This includes the costs for a Commission court reporter to transcribe hearings before the Commission and resulting transcripts. The estimate is based on nine days of hearings.

Q. PLEASE DESCRIBE THE OVERHEAD COSTS.

A. The Company is including the purchase overhead for authorized labor and nonlabor costs that are incurred to support the Company's purchasing functions that include authorized Supply Chain Company labor and benefits, Supply Chain consulting services, contract labor to support Supply Chain such as planners and buyers, license fees for evaluating credit profiles of vendors, facilities charges, employee expenses, and other miscellaneous expense. These costs are collected in a cost pool and are allocated out at month-end by applying overhead charges to eligible transactions.

B. <u>Rate Case Expense Update Process / Support</u>

Q. IS THE COMPANY PROVIDING ADDITIONAL INFORMATION TO SUPPORT ITS REQUESTED RATE CASE EXPENSES?

A. Yes. The discussion above and Attachment JJP-1 show estimated rate case expenses by major category, consistent with the Company's Direct Testimony in prior rate cases. The Company also will provide intervenors with workpapers supporting the rate case expense request.

Q. IS IT YOUR EXPERIENCE THAT ADDITIONAL INFORMATION IS PROVIDED THROUGH DISCOVERY?

A. Yes. In the past, intervenors have requested additional information through discovery. These discovery requests have resulted in production of highly confidential unredacted/confidential redacted copies of outside legal counsel and consultant invoices, as applicable, engagement letters, and other supporting documentation if available. While a separate motion will be filed at the appropriate time in the case, it is expected that the highly confidential unredacted legal invoices will be provided to Staff and UCA only, unless otherwise ordered by the Commission, with remaining parties receiving the confidential redacted versions provided they have signed and filed an appropriate non-disclosure agreement.

Q. WILL THE COMPANY UPDATE ITS ESTIMATED RATE CASE EXPENSE AS THIS CASE PROCEEDS?

A. Yes. The Company will update its rate case expenses amount in Rebuttal Testimony for actuals incurred through that time and may revise its estimate if needed. This kind of updating occurred in the Company's last gas rate case (Proceeding No. 22AL-0046G).

Q. **IF THE COMPANY'S RATE CASE EXPENSE REQUEST IS APPROVED, WILL THE COMPANY RECOVER THE ENTIRE AMOUNT IN ONE YEAR?**

A. No. As I discussed earlier in my Direct Testimony, the Company is proposing to create a regulatory asset for its rate case expenses and amortize recovery of the asset over 36 months, thereby delaying the Company's recovery and reducing the monthly impact on customers.

Q. IN THE CONTEXT OF THE CURRENT POLICY DISCUSSIONS SURROUNDING RATE CASE EXPENSES, CAN THE CURRENT LEVEL OF RATE CASE EXPENSES PROPOSED IN THIS CASE BE CONSIDERED REASONABLE?

A. Yes, absolutely. Rate cases are long and complex affairs critical to setting rates the ensure the financial health of the utility and reasonable rates to customers. Rate case expenses primarily go towards attorneys and consultants who have the skill, capacity, and expertise to develop a robust record on all issues in a rate case. It is that record that allows the Commission to decide the multitude of issues in the rate case and to make rate determinations with confidence. The Company strives for efficiency in its regulatory processes, and the focus of rate case expense reform efforts should be on improving the efficiency of the process, and not on determining an arbitrary level of expenses that are reasonable or not reasonable.

Q. IS THIS LEVEL OF EXPENSE REASONABLE FOR A CASE OF THIS MAGNITUDE?

A. Yes. In my opinion and based upon my experience, the level of rate case expenses recovery requested by Public Service in this case is reasonable and prudent. Public Service has access to rate case expense detail from its other operating companies and jurisdictions, and some of those jurisdictions incur significantly higher rate case expenses than Public Service for comparably sized cases. For example, a settlement to the most recent electric rate case filed in Texas[38] by Southwestern Public Service Company ("SPS", another Xcel Energy operating

[38] Unanimous Settlement filed December 22, 2023 in Docket No. 54634 at the Public Utilities Commission of Texas.

company) included an agreement to recover $4.5 million of rate case expenses. This level of rate case expenses is less than or comparable to other Texas utilities; for example, Entergy received approval for $4.8 million in rate case expenses in its most recent rate case[39], while Oncor recently received approval of $8.6 million in rate case expenses[40]. The different levels of rate case expense incurred between the Texas utilities and this instant proceeding do not imply that SPS or the other Texas utilities are incurring expenses imprudently. Rather, it stems from the regulatory requirements surrounding each proceeding that are a result of past regulatory decisions and filing package rules. The requirements in Texas result in more expert witness testimony and significantly more documents created as part of the filing process. This underscores the point that it is the efficiency of the regulatory process itself that is the primary driver of rate case expense levels for any given proceeding.

---

[39] Unopposed Stipulation and Settlement Agreement filed May 10, 2023 in Docket No. 53719 at the Public Utilities Commission of Texas.
[40]Order on Rehearing, July 30, 2023 in Docket No. 53601 at the Public Utilities Commission of Texas

VII. PROPOSED TARIFF CHANGES

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the Company's proposed tariff revisions stemming from its proposals in this proceeding. The proposed changes to tariffs include the incorporation of updates to standardized costs for gas line extensions, a new revenue deferral surcharge ("RDS") tariff, a new RSM reflecting the Company's revenue decoupling proposal, an updated GRSA based on the Company's proposed revenue requirement and implementation proposal discussed by Mr. Berman, an updated schedule of charges for rendering service, an updated Quality of Service Plan ("QSP") tariff, and an updated GCA tariff (including changes to the deferred gas cost and GSIC). Attachment JJP-2 and JJP-3 include the clean and redlined tariffs, respectively.

To help provide clarity to the timing of the Company's proposals in this proceeding – regarding the effective date of new rates, the implementation date of new rates and the RDS, and the implementation of the RSM – I have created a graphic (included as Attachment JJP-4) to outline the sequence of implementation of all these components.

A. Standardized Costs

Q. PLEASE DISCUSS THE UPDATES TO THE STANDARDIZED COSTS IN THE COMPANY'S TARIFF.

A. Pursuant to Gas Rule 4210:

> …the standardized costs must be updated in a base rate proceeding, utilizing the average actual cost across the applicable customer class and line extension type for the most recent consecutive 12-month period for which compiled cost data is available at the time it initiates a base rate proceeding.

The Company does rely on standardized costs for its service laterals, meters, and regulators for residential and commercial customers (respectively) and, thus, has updated those estimated costs in this proceeding, consistent with the requirements of Gas Rule 4210. The Company has updated the standardized costs for service connections based on the latest averages for such equipment and construction costs, which are listed on Sheet Nos. R86 and R88 of the Company's gas tariff. Attachment JJP-2 and JJP-3 reflect the proposed clean and redlined tariff adjustments to update the standardized costs.

B. Revenue Deferral Surcharge

Q. PLEASE DISCUSS THE NEWLY PROPOSED REVENUE DEFERRAL SURCHARGE TARIFF.

A. As discussed earlier in my Direct Testimony, and in more detail in Company witness Mr. Berman's Direct Testimony, the Company proposes to defer the implementation of new rates stemming from this rate case on customer bills until February 15, 2025, at which point the costs from Winter Storm Uri in 2021 will no longer be a component of customers' monthly bills. As discussed by Company witness Mr. Berman, although the statutory rate effective date is no later than November 5, 2024, the Company requests a November 1, 2024 rate effective date in this case (after full suspension). From the rate effective date through February 14, 2025, the Company will defer incremental revenue for recovery through the RDS, which will begin on February 15, 2025. Attachment JJP-2 and JJP-3 contain the proposed tariff sheets to implement the RDS and Attachment JJP-4 shows the timeline of the RDS implementation.

C. <u>Revenue Stability Mechanism</u>

Q. PLEASE DISCUSS THE PROPOSED REVENUE STABILITY MECHANISM TARIFF.

A. As outlined in Company witness Mr. Amen's Direct Testimony, the Company proposes decoupling in the form of a RSM for the Residential ("Schedule RG") and Small Commercial ("Schedule CSG") customer classes, based on a total revenues approach. Attachment JJP-3 contains the proposed new gas RSM tariff that would implement the decoupling mechanism and Attachment JJP-4 shows the timeline of the RSM implementation, along with the RDS implementation.

Q. DO YOU WISH TO HIGHLIGHT ANY ASPECTS OF THE IMPLEMENTATION OF THE RSM TARIFF?

A. Yes. The proposed decoupling mechanism, like previous proposed decoupling mechanisms for the electric and gas sides of the business, accounts for the ongoing efficiency and conservation savings achieved through the Company's DSM plans in order to not double recover on any customer usage reductions.

Specifically, the DSM Acknowledgement of Lost Revenues ("DSM-ALR") helps provide renumeration to the Company for the foregone revenues it would have earned had it not been for annual gas DSM plans. Recognizing the Company recovers these revenues from the DSM Cost Adjustment ("DSMCA") already, the DSM-ALR for Schedules RG and CSG would be added to actual recovered revenues for those same customer rate schedules before comparing to the baseline or target level of fixed cost recovery as established in this instant proceeding.

Q. HOW WOULD THE DSM-ALR BE INCORPORATED INTO THE QUARTERLY CALCULATIONS FOR THE RSM?

A. Given that the Company proposes the RSM to be calculated and applied on a quarterly basis, the Company would rely on the annual forecasted Schedules RG and CSG DSM-ALR based on the most recent DSM filing in the fall of each year, but would create monthly estimates for those amounts. The Company would do this based on the monthly sales volumes from the R and CSG classes[41] and then multiply those monthly savings by the latest $/therm rate established for the DSM-ALR. The proposed RSM true-up process would then correct for any over- or under-recoveries based on the forecasted DSM-ALR.

[41] The Company would estimate the CSG share of commercial natural gas savings based on the CSG Rate Schedule share of total annual gas throughput among CSG, CLG, and IG customers.

Q. WHERE DOES THE COMPANY DESCRIBE THE FULL CALCULATION OF THE PROPOSED RSM?

A. In addition to the proposed RSM tariff, included as Attachment JJP-3, the Direct Testimony of Mr. Amen walks through the proposed process and calculations for monthly RSM amounts, which are then grouped into periods spanning three months that begin on November 1, 2024.

D. GRSA

Q. PLEASE DISCUSS THE TARIFF CHANGES STEMMING FROM THE PROPOSED CHANGE IN THE REVENUE REQUIREMENT.

A. As a result of the identified revenue deficiency in the Cost of Service Study, the Company proposes a GRSA of 31.07 percent to be applied on a volumetric basis, as discussed in Company witnesses Mr. Freitas's and Mr. Berman's Direct Testimonies. The Company proposes to revise the GRSA in its tariffs so that it is applied to base rates, exclusive of Service and Facility charges, with such change effective on November 1, 2024 but not implemented until February 15, 2025 consistent with the Company's RDS proposal. Attachment JJP-3 provides the tariff revisions to Sheet No. 48 in light of this proposed GRSA.

E. Charges for Rendering Services

Q. PLEASE DISCUSS THE TARIFF CHANGES REFLECTING UPDATED CHARGES FOR RENDERING SERVICE.

A. In rate cases, the Company tends to update its schedule of charges for rendering service, outlining the charges to customers for the Company to institute or reinstitute gas service (based on the timeliness of the request), trip charges to diagnosis problems that customers are having, overtime rates for work performed outside of 8am-5pm (excluding Sundays), the charge for processing customer checks returned to the Company by the bank, and costs for certain data reports, among others. These changes reflect updates to the Company's labor and other internal costs applicable to the charges outlined. Company witness Mr. Freitas provides the revenue and O&M cost adjustments associated with these changes. Attachment JJP-3 provides the proposed tariff revisions to Sheet No. 12, reflecting the updated Charges for Rendering Service.

F. Gas Quality of Service Plan

Q. PLEASE DISCUSS THE PROPOSED TARIFF CHANGES TO THE COMPANY'S GAS QUALITY OF SERVICE PLAN.

A. Company witness Lauren Gilliland supports the Company's proposal to extend the existing QSP for an additional two years, through 2026, and in doing so retain the metrics that just became effective on January 1, 2023. Attachment JJP-3 provides the proposed revisions to Sheet No. 70, implementing this QSP extension.

G. GCA

Q. PLEASE DISCUSS THE PROPOSED TARIFF CHANGES TO THE COMPANY'S GCA TARIFFS.

A. As discussed previously in Section V of my testimony, Public Service proposes to change the return applied to gas storage inventory balances to the Company's WACC rather than a short-term debt rate – reverting back to its historical treatment.

Attachments JJP-2 and JJP-3 outline the proposed change to Sheet 50C of the Company's GCA tariff to effectuate this recommendation.

Q. IS THERE ANOTHER PROPOSED CHANGE TO THE GCA TARIFF?

A. Yes, the Company also proposes an adjustment to the deferred gas cost definition in the GCA tariff to include a reference to any true up balances from any over- or under-recoveries stemming from the RDS, which would be included as part of the Q2 GCA filing to be effective April 1, 2025 and collected over the subsequent 12 months.

VIII. COMPLIANCE AND OTHER MATTERS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I address certain requirements for rate case filings that result from SB 23-291 and the Commission's subsequent temporary rules for rate case filing procedures adopted in Proceeding No. 23R-0408EG ("Temporary Rules"). While much of the work around compliance with this legislation and accompanying rules is set forth in the Company's Advice Letter and in the Direct Testimony of Company witness Mr. Freitas, I provide a brief overview about how the Company has approached these new requirements in this case. I also address certain additional items that arose from Commission decisions in other Company proceedings and may be applicable to this rate case.

Q. PLEASE IDENTIFY THE KINDS OF NEW REQUIREMENTS SET FORTH IN SB 23-291 AND THE COMMISSION'S RESULTING TEMPORARY RULES.

A. SB 23-291 and the Temporary Rules include a variety of new requirements, with some relating to the kinds of information to be included in an initial rate case filing and others relating to certain costs that are no longer recoverable by the utility. Public Service's Advice Letter in this proceeding identified the initial filing requirements, and Mr. Freitas addresses how the Company has addressed the requirements around the cost of service study and supporting materials, historical test year, and prohibited expenses. Earlier in my Direct Testimony, I referenced the Rate Trend Report requirement required by the Commission's rules.

Q. HAVE THE REQUIREMENTS OF SB 23-291 AND THE COMMISSION'S TEMPORARY RULES BEEN PREVIOUSLY TESTED IN A RATE CASE BEFORE THE COMMISSION?

A. No. Given the timing of the legislation and the new rules, as far as I am aware, this is the first rate case in which a Colorado public utility is attempting to meet all the new requirements with the initial filing of its case. This is a challenge, because the legislation and rules do not necessarily detail how to comply with or to interpret each requirement, and any utility must determine how best to meet the requirements while working within existing systems and procedures. Public Service has worked very hard to meet these requirements to the best of its ability and in the accompanying Advice Letter has asked the Commission to certify its filing as complete, accordingly.

Q. SEPARATELY, CAN YOU ADDRESS COMPLIANCE WITH DIRECTIVES FROM THE COMMISSION'S INVESTIGATION INTO AVAILABLE FEDERAL FUNDING AND INCENTIVES?

A. Yes. As part of its investigation into the funding and incentives enacted through the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022 (in Proceeding No. 23M-0053ALL), the Commission has directed utilities to:

> In each filing utilities shall discuss how they plan to capture and optimize the benefits from these laws. Please identify the maximum available incentive related to the area of work identified within the filing and why the planned level of

> funding being pursued or planned on being pursued is most appropriate and most beneficial for ratepayers. [42]

The incentives, funding, and tax credits made available through these federal laws largely do not apply to the work the Company discusses in this proceeding regarding the spending and investments in the gas system made over the course of 2022 and 2023. While the new energy efficiency and electrification incentives for customers and new hydrogen funding will likely play larger roles for the Company's gas system moving forward, these measures are not significant components of the Company's cost structure for its natural gas business today. However, the Company will continue to discuss the vital role that federal incentives will play in cost-effective NPA portfolios, customer adoption of new technologies, and overall emissions reductions in future gas filings, to the extent required.

Q. ARE THERE OTHER ITEMS FROM THE COMPANY'S LAST GAS RATE CASE THAT YOU WOULD LIKE TO ADDRESS?

A. Yes, two items. First, in the Company's 2022 Combined Gas Rate Case, the Commission rejected recommendations from Trial Staff and UCA to disallow costs related to certain gas gathering assets – given an ongoing proceeding at the time (Proceeding No. 22A-0140G) investigating the Company's request to abandon or sell four gas gathering systems – but stated that they "expect[] that the outcomes from Proceeding 22A-0140G will be reflected in the costs reviewed in a future rate proceeding."[43] In the same context, the Commission also noted that in proceedings where there are stranded asset concerns, filings should "address

[42] Proceeding No. 23M-0053ALL, Decision No. C23-0811 ¶ 81.
[43] Decision No. C22-0804, Proceeding 22AL-0046G, ¶ 25.

comprehensively ratemaking and performance incentive options regarding treatment of cost recovery for assets that have been retired or sold with significant undepreciated balances."[44] Second, in the Company's last gas rate case, Staff expressed interest in having the Company increase communications prior to interruptions and establish guidelines for choosing priority of interruptions, culminating in a report.[45] I address these items here.

Q. ARE THERE COSTS ASSOCIATED WITH GAS GATHERING ASSETS IN THIS PROCEEDING?

A. No. The Company incurred a loss of about $384,000 on the sale of gas gathering assets in 2023, for which the Company is not requesting recovery in this proceeding or otherwise. As discussed in the Direct Testimony of Mr. Freitas, there are no costs associated with gas gathering assets in the cost of service.

Q. DID THE COMPANY HAVE ANY OTHER GAINS OR LOSSES ON PROPERTY ASSETS DURING THE TEST YEAR?

A. Yes. The Company sold its Golden Service Center, which provided both gas and electric service operations, in an effort to further consolidate and achieve efficiencies with its operations. The sale resulted in a $1.7 million loss for the building on the depreciable property for Public Service and a gain of about $4.7 million on the value of the non-depreciable land.

---

[44] Decision No. C22-0804, Proceeding 22AL-0046G, ¶ 31.

[45] *See* Decision No. C22-0642, ¶ 366, in Proceeding No. 22AL-0046G. While the Commission did not require such a report, I address this request briefly here. The Company also plans to address credit and risk and the establishment of security requirements for Transportation service terms and conditions in its next Phase II filing.

Q. HOW IS THE COMPANY PROPOSING TO ACCOUNT FOR THESE GAINS AND LOSSES IN THIS PROCEEDING?

A. Based specifically on the facts of this case and the Company's efforts to limit disputes in this proceeding where possible, the Company is proposing to apply the same treatment afforded to non-depreciable assets – namely, the Company's right to absorb those gains and losses entirely, consistent with judicial directions[46] – to the sales of the depreciable gas gathering assets and Golden Service Center building. The Company's voluntary absorption of losses from gas gathering and the service center building (based upon retention of the gain) is to the benefit of customers at a total of approximately $2.1 million across Public Service. The portion of these losses from gas gathering and the sale of the Golden Service Center building allocated to the gas business results in losses of about $0.8 million.

Q. WHY IS THIS A REASONABLE APPROACH IN THIS CASE?

A. In this instance, it is a benefit to customers for the Company to absorb the relatively limited losses on prudent sales of the depreciable property. Conversely, the gain on the sale of land belongs to the Company, as it represents the proceeds from the sale of a non-depreciable asset. An alternative would be for customers to bear either a portion or all of the losses associated with these sales, but the Company is not opting to make such a proposal at this time. Neither is this approach intended to foreclose a different ratemaking discussion under different

[46] *See Public Service Company of Colorado v. Public Utilities Commission of the State of Colorado, et al.,* Case Number 20CV32793, Opinion and Order at 8-12 (January 6, 2022), which addressed the Company's appeal to the Denver District Court on the treatment of gains and losses on asset sales.

circumstances; rather, the Company is proposing this outcome in the interest of simplicity of ratemaking in this case.

Q. HOW IS THE COMPANY ADDRESSING STAFF'S DESIRE FOR A REPORT REGARDING INTERRUPTIBLE CUSTOMERS FOLLOWING WINTER STORM URI?

A. The Company will submit a report in the very near future in Proceeding No. 21A-0192EG (Winter Storm Uri) regarding interruptible service and the steps the Company has undertaken with interruptible customers to help educate them on their obligations, available rates, the results of curtailment demonstrations tests, and the Company's ability to move interruptible customers to firm service when interruptible service requirements are not met. The Company will otherwise discuss available rates and rate design in a subsequent Phase II gas rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Jason J. Peuquet

Jason Peuquet is a Director of Regulatory Administration. In this role, he is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado. In his prior role with Xcel Energy, as Strategy and Policy Manager for the Clean Transportation team, he focused on policy and program development to expand clean transportation opportunities for customers throughout the eight midwestern and western states in which Xcel Energy operates. He has testified before the Colorado Public Utilities Commission and the New Mexico Public Regulation Commission.

Mr. Peuquet previously worked as a Policy Advisor to the Mike Bloomberg 2020 campaign and as a Senior Economist at the Colorado Public Utilities Commission, where he focused on energy, financial, and environmental policy analysis. He also served as the Research Director for a non-partisan think tank in Washington, DC – the Committee for a Responsible Federal Budget. Jason has Bachelor of Arts degrees in Economics and International Affairs from the George Washington University, where he graduated summa cum laude, and a Master in Public Policy degree from Harvard University's Kennedy School of Government.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1029-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC 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 EFFECTIVE FEBRUARY 29, 2024	)	**PROCEEDING NO. 24AL-______G**

AFFIDAVIT OF JASON J. PEUQUET
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Jason J. Peuquet, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 29th day of January, 2024.

Jason J. Peuquet
Jason J. Peuquet
Director of Regulatory Administration

Subscribed and sworn to before me this 29th day of January, 2024.

Carlye Harrison
Notary Public

CARLYE HARRISON
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20224029216
MY COMMISSION EXPIRES JULY 26, 2026

My Commission expires July 26, 2026

Public Service Company of Colorado
Rate Case Expenses
2024 Phase I Gas Rate Case Estimate/Summary of Rate Case Expenses

Line No.	Category	Description of Service		Estimate
1	**Phase I and II Rate Case Expenses**			
2	**Legal Counsel**			
3	Taft Stettinius & Hollister LLP	Regulatory Legal Counsel		985,000
4	Wilkinson, Barker, Knauer, LLP	Regulatory Legal Counsel		250,000
5	**Total Legal Counsel** *(sum of lines 3 and 4)*		**$**	**1,235,000**
6	**Consultants**			
7	Brattle Group	ROE		160,000
8	Atrium Economics, LLC	Decoupling		100,000
9	**Total Consultants** *(sum of lines 7 and 8)*		**$**	**260,000**
10	**Customer Noticing**			
11	Noticing Bill Onsert			15,000
12	Noticing Newspaper	Denver Post 2 consecutive Weeks		27,000
13	Transcription to Spanish	(Noticing Bill Onsert)		600
14	**Total Customer Noticing** *(sum of lines 11, 12, and 13)*		**$**	**42,600**
15	**Hearing Transcripts**			
16	Hearing Transcripts		**$**	**23,063**
17	**Total Rate Case Expenses Estimate excluding pruchasing load** *(sum of lines 5, 9, 14 and 16)*		**$**	**1,560,663**
18	**Purchasing Load**			
19	Total Purchasing Load (1.08% of estimate)		$	16,855
20	**Total Rate Case Expense Estimate** *(sum of lines 17 and 19)*		**$**	**1,577,518**

PUBLIC SERVICE COMPANY OF COLORADO

Twenty-Sixth Revised Sheet No. 3

P.O. Box 840
Denver, CO 80201-0840

Twenty-Fifth Revised Cancels Sheet No. 3

TABLE OF CONTENTS

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE February 29, 2024

GAS RATES	RATE	
GAS SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
To institute or reinstitute gas service requiring a premise visit within:		
24 hours	$112.00	I
12 hours	152.00	I
To institute or reinstitute both gas and electric service requiring a premise visit within:		
24 hours	167.00	I
12 hours	234.00	I
To transfer service at a specific location from one customer to another customer where such service is continuous, either gas service or both gas and electric service at the same time not requiring a premise visit	8.00	
To provide a non-regularly scheduled final meter Reading at customers request	25.00	
To perform non-gratuitous labor for service work in addition to charges for material is as follows:		
Trip Charge	61.00	I
(Assessed when no actual service work, other than a general diagnosis of the customer's problem)		
For service work during normal working hours, per man-hour	111.00	I
Minimum Charge, one hour	111.00	I

(Continued on Sheet No. 12A)

PUBLIC SERVICE COMPANY OF COLORADO

Fourteenth Revised Sheet No. 12A

P.O. Box 840
Denver, CO 80201-0840

Cancels
Thirteenth Revised Sheet No. 12A

GAS RATES	RATE	
GAS SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday.		
The overtime rate shall be, per man hour	142.00	I
Minimum Charge, one hour	142.00	I
When such service work is performed on Sundays and holidays, per man hour	172.00	I
Minimum Charge, one hour	172.00	I
To process a check from a customer that is returned to the Company by the bank as not payable	$ 15.00	
To achieve payment from a Non-Residential Service customer who chooses to pay his/her monthly natural gas bill with a credit or debit card, a per transaction convenience fee of 2.2% of the payment amount shall be charged for any credit or debit card payment by the Company’s third party vendor that processes credit card payments.		
To achieve payment from a Residential Service customer who chooses to pay his/her monthly natural gas bill with a credit or debit card, a per transaction convenience fee of $1.50 shall be charged for any credit or debit card payment by the Company’s third party vendor that processes credit card payments.		
For a customer with a combined gas and electric bill, the per transaction convenience fee shall be assessed only once when a customer pays his/her combined gas and electric monthly bill as a single credit or debit card transaction.		

(Continued on Sheet No. 12B)

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE February 29, 2024

PUBLIC SERVICE COMPANY OF COLORADO

Thirty-Second Revised Sheet No. 48

P.O. Box 840
Denver, CO 80201-0840

Thirty-First Revised Cancels Sheet No. 48

NATURAL GAS RATES
GENERAL RATE SCHEDULE ADJUSTMENT

GRSA:
The charge for gas service calculated under Company's gas base rate schedules shall be adjusted by the percentage listed below: T T

0.03%

Effective November 1, 2024, but not implemented on customer bills until February 15, 2025, the charge for gas service calculated under Company's gas base rate schedules shall be adjusted by the percentage listed below, replacing any other GRSA but not the GRSA-P. Said adjustments shall not apply to Service and Facility charges applicable to each rate schedule. N N N N N

31.07% N

GRSA- Pipeline System Integrity Adjustment (GRSA-P):

The charge for natural gas service calculated under the Company's natural gas base rate schedules shall be adjusted by the percentages listed below.

Residential Service	
RG	-1.00%
RGL	-0.57%
Commercial & Industrial Sales Service	
CSG	-1.18%
CLG	-1.92%
CGL	-0.41%
IG	-4.25%
Gas Transportation Service	
TFS	-1.63%
TFL	-2.21%
TI	-4.40%

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE February 29, 2024

PUBLIC SERVICE COMPANY OF COLORADO

Tenth Revised Sheet No. 49

P.O. Box 840
Denver, CO 80201-0840

Ninth Revised Cancels Sheet No. 49

NATURAL GAS RATES
REVENUE DEFERRAL SURCHARGE N

APPLICABILITY N

Through Decision No. CXX-XXXX issued in Proceeding No. 24AL-XXXXG (the "Decision"), the Commission approved, among other things, base rate revenue increases and new rates for the Company's natural gas customers, effective on the Rate Effective Date of November 1, 2024. Without changing the Rate Effective Date or the Company's ability to recover incremental revenue as of the Rate Effective Date, the Commission authorized the Company to defer the incremental revenue authorized by the Decision and record it in a regulatory asset, with a return at the weighted average cost of capital, during the Deferral Period. Consequently, beginning February 15, 2025 and during the Incremental Revenue Recovery Period, the base rate charges for natural gas service calculated under the Company's natural gas base rate schedules shall be adjusted by the RDS Amounts. N

RDS DESCRIPTION N

Through the RDS, the Company will bill and collect the Deferred Incremental Revenue by rate schedule. The RDS will also include the initial first period of the Revenue Stability Mechanism amount for Schedules RG and CSG stemming from the November 2024 through January 2025 period. The RDS amounts billed during the Incremental Revenue Recovery Period will be subject to a final RDS true-up by rate schedule to ensure that the Company recovers no more and no less Deferred Incremental Revenue than it would have recovered had the rates authorized by the Decision become effective on customer bills on the Rate Effective Date rather than February 15, 2025. The RDS applies to all base rate charges and terminates effective February 15, 2026. In August 2025, after six months of Deferred Incremental Revenue recovery, the Company will assess how the pace of revenues being recovered under the RDS compare to the initial estimates, and if recovered revenues differ by more or less than 20 percent of estimates at that point in time, the Company will file an interim adjustment to RDS Amounts in September 2025 to be effective on October 1, 2025 to help minimize any true up amount. N

REQUIRED FILINGS N

1. On or before January 31, 2025, a compliance advice letter and tariff filing are required to be made with the Commission to be effective on the Rate Implementation Date, in order to accomplish the following: N

   a) Reflect on the tariff sheets and, thus, place into effect on customer bills, the rates approved by the Decision; and N
   b) Place into effect the RDS for each rate schedule. Supporting workpapers for calculation of the RDS will be included with this filing. N

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT
Regulatory and Pricing

EFFECTIVE DATE February 29, 2024

NATURAL GAS RATES
REVENUE DEFERRAL SURCHARGE N

2. The Company will make a compliance advice letter and tariff filing, on not less than five business days' notice, to remove the RDS, effective February 15, 2026. N

3. At the end of the RDS Deferral Period, the Company will calculate any under or over-recoveries of Deferred Incremental Revenue during the Deferral Period and include any such true-up amounts in the Company's Q2 Gas Cost Adjustment to be filed in March 2026 and recovered over the Q2 period. N

DEFINITIONS: N

The terms used in this tariff have the following meanings unless otherwise noted. N

Decision. Decision No. RXX-XXXX issued in Proceeding No. 24AL-XXXXG, the Company's 2024 natural gas rate case proceeding. N

Deferred Incremental Revenue. The amount of incremental revenue for the Deferral Period, which will be deferred and recorded in a regulatory asset, with a weighted average cost of capital return on the asset, as approved by the Decision. N

Deferral Period. The period November 1, 2024 through February 14, 2025. N

Incremental Revenue Recovery Period. February 15, 2025 through February 14, 2026. N

Rate Effective Date. November 1, 2024. N

Rate Implementation Date. February 15, 2025. N

RDS Amount. The RDS percent applied to each rate schedule reflecting the result of the relevant RDS calculation applied during the Incremental Revenue Recovery Period. N

RDS CALCULATION N
The amount of Deferred Incremental Revenue will be determined for each rate schedule by multiplying the rates approved by the Decision by actual monthly billing determinants from the Deferral Period, as available, then subtracting the actual base rate revenues collected from each rate schedule during the Deferral Period. The Company's authorized pre-tax weighted average cost of capital will be applied as interest to the Deferred Incremental Revenue. The Deferred Incremental Revenue will also include the initial first period of the Revenue Stability Mechanism amount for Schedules RG and CSG stemming from the November 2024 through January 2025 period. The total revenue requirement N

PUBLIC SERVICE COMPANY OF COLORADO

Third Revised Sheet No. 49B

P.O. Box 840
Denver, CO 80201-0840

Second Revised Cancels Sheet No. 49B

NATURAL GAS RATES
REVENUE DEFERRAL SURCHARGE N

RDS CALCULATION - Cont. N

for each rate schedule will then be divided by the forecasted base rate revenues for each rate schedule during the Incremental Revenue Recovery Period. N

TRUE-UP N

After conclusion of the Incremental Revenue Recovery Period, the amount of the Deferred Incremental Revenue will be subject to a final true-up by rate schedule based on actual billing determinants during the Incremental Revenue Recovery Period, and, as required by the Decision, will be applied by rate schedule to the Gas Cost Adjustment ("GCA"), beginning with the GCA to become effective on April 1, 2026. N

RATE TABLE N

For the Incremental Revenue Recovery Period, the charge for natural gas service calculated under the Company's natural gas base rate schedules, exclusive of any GRSAs, shall be adjusted by the percentages listed below. N

Rate Schedule	Revenue Deferral Surcharge	
Residential Service		N
RG	10.14%	N
RGL	9.96%	N
Commercial & Industrial Sales Service		N
CSG	9.06%	N
CLG	9.29%	N
CGL	10.22%	N
IG	10.44%	N
Gas Transportation Service		N
TFS	10.46%	N
TFL	9.40%	N
TI	9.79%	N

PUBLIC SERVICE COMPANY OF COLORADO

Sixteenth Revised Sheet No. 50A

P.O. Box 840
Denver, CO 80201-0840

Fifteenth Revised Cancels Sheet No. 50A

NATURAL GAS RATES
GAS COST ADJUSTMENT

DEFINITIONS - Cont'd

Average Gas Storage Inventory Balance. The annual average of the forecasted monthly average gas storage inventory balances for the GCA Effective Period.

Base Rate(s). The Company's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the Company's last general rate case.

Current Gas Cost. A rate component of the GCA, expressed in mils per dekatherm ($0.001 per Dth), which is the sum of the Gas Commodity Cost, Upstream Service Cost and the Gas Storage Inventory Cost projected to be incurred by the Company during the GCA Effective Period divided by the applicable Forecasted Sales Gas Quantity.

Deferred Gas Cost. Gas costs accumulated in the Company's Account No. 191, which can be over- or under-recoveries, calculated by subtracting Recovered Gas Cost from Actual Gas Cost, as of the end of the month that is one month prior to the effective date of the GCA, adjusted for unbilled revenues, and including: (1) storage adjustments; (2) other costs authorized by the Public Utilities Commission; (3) Interest on Account No. 191 Balance, as authorized by the Public Utilities Commission; (4) the net Daily Imbalance Charges from transportation customers under the Shipper Daily Balancing Option; (5) the T
net Monthly Cashouts from transportation customers; and (6) true up of any T
over- or under-recoveries from the Revenue Deferral Surcharge in place for T
the 12 months beginning February 15, 2025. The Deferred costs will be offset T
by Unauthorized Overrun Penalties collected from customers.

Deferred Gas Reserve Tracker. Amounts will include a separate gas reserve component tracked in account No. 191 based on actual GCA costs that have risen above or fallen below a defined threshold. The threshold triggering use of this account consists of an upper limit of 180 percent of the average GCA over the last five calendar years less any current EGCRR rate and a lower limit of 80 percent of the average GCA over the last five calendar years. Any changes to the upper or lower limit will be effective in the third quarter GCA annually. If the GCA rate exceeds the upper dekatherm amount of the range the resulting gas reserve component balance, the amount above the upper limit will be included in the Deferred Gas Reserve Tracker, and if the GCA rate is under the lower dekatherm rate end of the range the amount below the lower limit may be included in the Deferred Gas Reserve Tracker. This tracker will be adjusted at the time the GCA rate is adjusted to ensure the rate remains in the defined range until the next filing. The Deferred Gas Reserve Tracker includes symmetrical interest on both under-recovered and over-recovered balances.

ADVICE LETTER NUMBER 1029		ISSUE DATE January 29, 2024
DECISION NUMBER	REGIONAL VICE PRESIDENT, Regulatory and Pricing	EFFECTIVE DATE February 29, 2024

PUBLIC SERVICE COMPANY OF COLORADO

Eleventh Revised Sheet No. 50B

P.O. Box 840
Denver, CO 80201-0840

Tenth Revised Cancels Sheet No. 50B

NATURAL GAS RATES
GAS COST ADJUSTMENT

DEFINITIONS - Cont'd

Forecasted Sales Gas Quantity. The quantity of gas commodity projected to be sold by the Company during the applicable GCA Effective Period, based upon the historic quantity of gas commodity sales, adjusted to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data and anticipated changes, except that for the Deferred Gas Cost rate component calculation, the Forecasted Sales Gas Quantity shall be the gas commodity projected to be sold during the 12-month period applicable to the Company's quarterly GCA application effective October 1. M M M M

Gas Commodity Cost. The total cost of the natural gas commodity that includes each of the following costs, as determined for each month within the GCA Effective Period: (1) the NYMEX Settlement Price as of the first business day of the month prior to the GCA Effective Period, adjusted for the basis differentials between the monthly NYMEX Settlement Price, which is based upon deliveries at the Henry Hub, and the respective indexes applicable to the various areas where the Company purchases its gas supplies, multiplied by the purchase volumes for each corresponding month within the GCA Effective Period; (2) the monthly reservation fees or demand charges payable to gas sellers for making firm quantities of gas available for sale to Company irrespective of the commodity volume actually delivered (gas demand costs); (3) the physical fixed price purchases; (4) appropriate adjustments for storage gas injections and withdrawals; and (5) the gas price management costs.

Gas Cost Adjustment ("GCA"). The tariff mechanism by which a gas rate is adjusted on an expedited basis to reflect increases or decreases in rate components, such as the Deferred Gas Cost, Gas Commodity Cost, Upstream Service Cost and Gas Storage Inventory Cost.

GCA Effective Period. The period of time that the GCA rate change is intended to be in effect. The GCA Effective Period for the Gas Commodity Cost, and Deferred Gas Cost, components of the GCA rate is the three-month calendar quarter, except that for purposes of an interim GCA, the GCA Effective Period for the Gas Commodity Cost is either two months or one month, depending on the number of months remaining before the GCA Effective Period for the next regular quarterly GCA. The GCA Effective Period for the Upstream Service Cost and Gas Storage Inventory Cost components of the GCA rate is typically twelve months, from October 1 through September 30, except that for purposes of a regular quarterly GCA, the GCA Effective Period for the Upstream Service Cost and Gas Storage Inventory Cost components of the GCA rate is the remainder of such twelve-month period.

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT,
Regulatory and Pricing

EFFECTIVE DATE February 29, 2024

PUBLIC SERVICE COMPANY OF COLORADO

Thirteenth Revised Sheet No. 50C

P.O. Box 840
Denver, CO 80201-0840

Twelfth Revised Cancels Sheet No. 50C

NATURAL GAS RATES
GAS COST ADJUSTMENT

DEFINITIONS - Cont'd

Gas Storage Inventory Cost. A rate component of the GCA, expressed in mils per dekatherm ($0.001 per Dth) which is the return applied to the Average Gas Storage Inventory Balance divided by the Forecasted Sales Gas Quantity. The return applied to the Average Gas Storage Inventory Balance shall be based on the Company's weighted average cost of capital. The return will be adjusted for income taxes before being multiplied by the Average Gas Storage Inventory. T T

Interest on Account No. 191 Balance. For amounts outside of the Deferred Gas Reserve Tracker, interest at a rate equal to the interest rate paid on customer deposits as set forth in the General Terms and Conditions will be applied to the Account No. 191 Deferred Gas Cost Balance on an average monthly basis. The disposition of any net interest on over- or under-recovered gas costs shall be as directed by orders of the Public Utilities Commission in Docket Nos. 02A-267G and 08A-095G. T T T

Recovered Gas Cost. The gas costs recovered by the Company, which shall be calculated by applying the GCA rate to actual sales quantities billed for the period the GCA rate was in effect. N N

Upstream Service Cost. The total cost of all transmission, gathering, compression, balancing, treating, processing storage and like services performed by others under contract with the Company for the purpose of effectuating delivery of gas commodity to the Company's jurisdictional natural gas facilities.

CURRENT GAS COST RATE DETERMINATION

Current Gas Cost shall be calculated to the nearest mil per Dth according to the following formula:

Current Gas Cost = A + B + C

A = Gas Commodity Cost
B = Upstream Service Cost
C = Gas Storage Inventory Cost

(Continued on Sheet No. 50D)

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT, Regulatory and Pricing

EFFECTIVE DATE February 29, 2024

PUBLIC SERVICE COMPANY OF COLORADO

Second Revised Sheet No. 52

P.O. Box 840
Denver, CO 80201-0840

First Revised Cancels Sheet No. 52

NATURAL GAS RATES
REVENUE STABILITY MECHANISM ("RSM") Adjustment N

APPLICABILITY N
Rate Schedules RG and CSG are subject to a Revenue Stability Mechanism (RSM). The RSM factors for the applicable rate schedules will be applied through a $/therm charge. N

DEFINITIONS N

ACTUAL MARGIN PER CUSTOMER CLASS (AMPCC) N
The AMPCC is the Current Period base rate revenues collected by the Company and not adjusted for weather, inclusive of General Rate Schedule Adjustments (GRSA or GRSA-P). Calculated separately for Schedules RG and CSG. N

TARGET NORMALIZED MARGIN PER CUSTOMER CLASS (TNMPCC) N
The TNMPCC is calculated using test year base rate revenues established by the Commission in a previous rate case or other applicable proceeding, by using the Base Rate Charges and GRSAs or GRSA-P factors that were in place during the Current Period multiplied by the weather normalized billing determinants for the Current Period. Calculated separately for Schedules RG and CSG. N

CURRENT PERIOD N
The three (3) month period for which the RSM is being calculated. The initial Current Period shall be the November 2024 through January 2025 period, and subsequent periods will be every 3 months thereafter. N

DEMAND-SIDE MANAGEMENT ACKNOWLEDGEMENT OF LOST REVENUE (DSM-ALR) N
The Commission approved acknowledgement of lost revenue, as defined on Sheet No. 42A, that is in place for the Current Period. The Company will use the Commission approved DSM-ALR from the most recent DSM plan as the basis for an initial estimate, and any over- or under-recoveries will be included as part of the DSM-ALR True-Up. Calculated separately for Schedules RG and CSG. N

RECOVERY TIMEFRAME N
The timeframe over which the RSM factors will be in place. The RSM will be billed over a 12-month period. The initial Recovery Timeframe will be from July 1, 2025 through June 30, 2026, which will reflect the second full period of the RSM. The initial first period will be recovered through the Revenue Deferral Surcharge. N

RSM AMOUNT N
The difference between the TNMPCC and the AMPCC, less the Variable Operating Costs, plus Current Period DSM-ALR, plus the RSM True-Up amount (if any) and the DSM-ALR True-up amount (if any), either positive or negative. Calculated separately for Schedules RG and CSG. N

ADVICE LETTER NUMBER	1029	ISSUE DATE	January 29, 2024
DECISION NUMBER	VICE PRESIDENT, Rates & Regulatory Affairs	EFFECTIVE DATE	February 29, 2024

NATURAL GAS RATES
REVENUE STABILITY MECHANISM ADJUSTMENT N

DEFINITIONS – Cont'd N

RSM TRUE-UP N

The over-recovery or under-recovery of RSM amounts after the 12 months of billing is complete. The RSM True-up value consists of the difference between the revenue the RSM factor was designed to collect (the Current Period RSM Amount) and the actual revenue collected through the RSM factor during the Recovery Timeframe. Calculated separately for Schedules RG and CSG. N

DSM-ALR TRUE-UP N

The difference between the DSM-ALR forecast and the actual DSM-ALR for the Calendar Year, included as part of the third period RSM Amount. Calculated separately for Schedules RG and CSG. N

VARIABLE OPERATING COSTS N

The costs associated with FERC Accounts 755, 819, 854, and 873 that are included in the Base Rate Usage Charges for Schedules RG and CSG from the previous rate case or other applicable proceeding. Calculated separately for Schedules RG and CSG. N

REVENUE STABILITY MECHANISM RATE CALCULATIONS N

Calculated separately for Schedules RG and CSG. N

RSM Amount = TNMPCC - AMPCC - Variable Operating Costs - DSM-ALR +/- RSM True Up +/- DSM-ALR True Up N

Current Period RSM Rate = RSM Amount ÷ Forecasted Volume for Recovery Timeframe (therms) N

Total RSM Rate = The summation of the Current Period RSM Rate and the prior three periods' RSM Rate, if applicable. N

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

Second Revised Sheet No. 52B

First Revised Cancels Sheet No. 52B

NATURAL GAS RATES
REVENUE STABILITY MECHANISM ADJUSTMENT N

Rate Schedule	Billing Units	RSM Rates	
RG	Therm	$0.XXXXX	N
CSG	Therm	$0.XXXXX	N

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

NATURAL GAS RATES
QUALITY OF SERVICE PLAN (QSP)

QSP PERFORMANCE BASELINE

QSP APPROVAL PERIOD: January 1, 2022 through December 31, 2026 C

SAFETY:

a) Damage Prevention

Objective: Lower damages/1000 locates
Penalty: $250,000
Performance Baseline: Damages exceed 1.47 damages/1000 locates T

b) Emergency Response

Objective: Improve responsiveness in potential emergency situations
Penalty: $250,000
Performance Baseline: Response falls below 95 percent within 60 T
minutes T

RELIABILITY:

a) Grade 2 Leak Repair Time

Objective: Decrease the amount of methane released into environment
Penalty: $250,000
Performance Baseline: Repair time exceeds 52 days T

PUBLIC SERVICE COMPANY OF COLORADO

Sub. Fourth Revised Sheet No. R86

P.O. Box 840
Denver, CO 80201-0840

Third Revised Cancels Sheet No. R86

RULES AND REGULATIONS

NATURAL GAS SERVICE

DISTRIBUTION EXTENSION POLICY

STANDARD CONSTRUCTION COSTS AND CREDITS

Construction Costs		
Residential On-Site Distribution Extension Per Lot Cost	$ 1,741	I
Residential Service Lateral Extension < 100 Ft. Cost	$ 1,521	
Residential Service Lateral >100ft. Cost Per Foot	$ 9.46	
Per Meter Set Costs (customer share)		
Residential Per Meter Set Cost	$ 291	
CSG Per Meter Set Cost	$ 1,690	
All Other Per Meter Set Cost	$ 6,338	

Off-Site Distribution Main Extension Credit (not available for applications dated on or after November 1, 2023 unless terminated earlier pursuant to Commission decision)

Off-Site Distribution Main Extension Credit	28.00%

The above costs and credits may be recalculated and revised from time to time as determined necessary by the Company based on the same method(s) as approved by the Commission. An additional charge may be applicable for special items, including without limitation any Applicant-associated delays; obstructions; permit fees; or any special item required to meet construction conditions, including but not limited to frost conditions and rock conditions.

The Off-Site Distribution Main Extension Credit is a twenty-eight percent (28%) credit applied to an Applicant's Construction Costs for an Off-Site Distribution Main Extension. In the event that excess Construction Allowance is awarded to an Off-Site Distribution Main Extension, this credit shall be applied after the Construction Allowance has been applied. The Off-Site Distribution Main Extension Credit is not available for applications dated on or after November 1, 2023 unless terminated earlier pursuant to Commission decision.

ADVICE LETTER NUMBER 1029

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT
Regulatory and Pricing

EFFECTIVE DATE February 29, 2024

RULES AND REGULATIONS

NATURAL GAS SERVICE

DISTRIBUTION EXTENSION POLICY

ON-SITE STANDARD CONSTRUCTION COSTS AND CONSTRUCTION ALLOWANCE WORKSHEET

	Per Lot Standard Cost $	Construction Allowance $	Customer Responsibility $	
Gas	$ 1,741 [1]	$ (331) [2]	$ 1,410	II

[1] Standard Construction Costs and Credits - On-Site Distribution Extension Per Lot Cost
[2] Gas Residential Construction Allowance - Distribution Main Portion

An additional charge may be applicable for special items, including without limitation any Applicant-associated delays; obstructions; permit fees; or any special item required to meet construction conditions, including but not limited to frost conditions and rock conditions.

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

Sheet No. 3

Cancels
Sheet No. 3

TABLE OF CONTENTS

COLO. PUC No. 6 Gas

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 12

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No. 12

GAS RATES	RATE	
GAS SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
To institute or reinstitute gas service requiring a premise visit within:		
24 hours	$112~~01~~.00	I
12 hours	152~~37~~.00	I
To institute or reinstitute both gas and electric service requiring a premise visit within:		
24 hours	167~~42~~.00	I
12 hours	234~~199~~.00	I
To transfer service at a specific location from one customer to another customer where such service is continuous, either gas service or both gas and electric service at the same time not requiring a premise visit	8.00	
To provide a non-regularly scheduled final meter Reading at customers request	25.00	
To perform non-gratuitous labor for service work in addition to charges for material is as follows:		
Trip Charge	61~~55~~.00	I
(Assessed when no actual service work, other than a general diagnosis of the customer's problem)		
For service work during normal working hours, per man-hour	111~~99~~.00	I
Minimum Charge, one hour	111~~99~~.00	I

(Continued on Sheet No. 12A)

ADVICE LETTER NUMBER

DECISION NUMBER

REGIONAL VICE PRESIDENT,
Rates & Regulatory Affairs

ISSUE DATE January 29, 2024

EFFECTIVE DATE

GAS RATES	RATE
GAS SERVICE	

SCHEDULE OF CHARGES FOR RENDERING SERVICE

An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday.

The overtime rate shall be, per man hour	142~~26~~.00	I
Minimum Charge, one hour	142~~26~~.00	I
When such service work is performed on Sundays and holidays, per man hour	172~~53~~.00	I
Minimum Charge, one hour	172~~53~~.00	I
To process a check from a customer that is returned to the Company by the bank as not payable	$ 15.00	

To achieve payment from a Non-Residential Service customer who chooses to pay his/her monthly natural gas bill with a credit or debit card, a per transaction convenience fee of 2.2% of the payment amount shall be charged for any credit or debit card payment by the Company’s third party vendor that processes credit card payments.

To achieve payment from a Residential Service customer who chooses to pay his/her monthly natural gas bill with a credit or debit card, a per transaction convenience fee of $1.50 shall be charged for any credit or debit card payment by the Company’s third party vendor that processes credit card payments.

For a customer with a combined gas and electric bill, the per transaction convenience fee shall be assessed only once when a customer pays his/her combined gas and electric monthly bill as a single credit or debit card transaction.

(Continued on Sheet No. 12B)

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 48

P.O. Box 840
Denver, CO 80201-0840

Cancels Sheet No. 48

NATURAL GAS RATES
GENERAL RATE SCHEDULE ADJUSTMENT

GRSA:
The charge for gas service calculated under Company's gas base rate schedules shall be adjusted by the percentage listed below~~. Said adjustments shall not apply to charges determined by the Gas Cost Adjustment provision on Sheet No. 50~~: T T

0.03%

Effective November 1, 2024, but not implemented on customer bills until February 15, 2025, the charge for gas service calculated under Company's gas base rate schedules shall be adjusted by the percentage listed below, replacing any other GRSA but not the GRSA-P. Said adjustments shall not apply to Service and Facility charges applicable to each rate schedule. N N N N N

31.07% N

GRSA- Pipeline System Integrity Adjustment (GRSA-P):

The charge for natural gas service calculated under the Company's natural gas base rate schedules shall be adjusted by the percentages listed below.

Residential Service	
RG	-1.00%
RGL	-0.57%
Commercial & Industrial Sales Service	
CSG	-1.18%
CLG	-1.92%
CGL	-0.41%
IG	-4.25%
Gas Transportation Service	
TFS	-1.63%
TFL	-2.21%
TI	-4.40%

ADVICE LETTER NUMBER

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

EFFECTIVE DATE

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 49

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No. 49

NATURAL GAS RATES

REVENUE DEFERRAL SURCHARGE N

APPLICABILITY N

Through Decision No. CXX-XXXX issued in Proceeding No. 24AL-XXXXG (the "Decision"), the Commission approved, among other things, base rate revenue increases and new rates for the Company's natural gas customers, effective on the Rate Effective Date of November 1, 2024. Without changing the Rate Effective Date or the Company's ability to recover incremental revenue as of the Rate Effective Date, the Commission authorized the Company to defer the incremental revenue authorized by the Decision and record it in a regulatory asset, with a return at the weighted average cost of capital, during the Deferral Period. Consequently, beginning February 15, 2025 and during the Incremental Revenue Recovery Period, the base rate charges for natural gas service calculated under the Company's natural gas base rate schedules shall be adjusted by the RDS Amounts. N

RDS DESCRIPTION N

Through the RDS, the Company will bill and collect the Deferred Incremental Revenue by rate schedule. The RDS will also include the initial first period of the Revenue Stability Mechanism amount for Schedules RG and CSG stemming from the November 2024 through January 2025 period. The RDS amounts billed during the Incremental Revenue Recovery Period will be subject to a final RDS true-up by rate schedule to ensure that the Company recovers no more and no less Deferred Incremental Revenue than it would have recovered had the rates authorized by the Decision become effective on customer bills on the Rate Effective Date rather than February 15, 2025. The RDS applies to all base rate charges and terminates effective February 15, 2026. In August 2025, after six months of Deferred Incremental Revenue recovery, the Company will assess how the pace of revenues being recovered under the RDS compare to the initial estimates, and if recovered revenues differ by more or less than 20 percent of estimates at that point in time, the Company will file an interim adjustment to RDS Amounts in September 2025 to be effective on October 1, 2025 to help minimize any true up amount. N

REQUIRED FILINGS N

1. On or before January 31, 2025, a compliance advice letter and tariff filing are required to be made with the Commission to be effective on the Rate Implementation Date, in order to accomplish the following: N

   a) Reflect on the tariff sheets and, thus, place into effect on customer bills, the rates approved by the Decision; and
   b) Place into effect the RDS for each rate schedule. Supporting workpapers for calculation of the RDS will be included with this filing. N

ADVICE LETTER NUMBER

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT
Regulatory and Pricing

EFFECTIVE DATE

NATURAL GAS RATES
REVENUE DEFERRAL SURCHARGE N

2. The Company will make a compliance advice letter and tariff filing, on not less than five business days' notice, to remove the RDS, effective February 15, 2026. N

3. At the end of the RDS Deferral Period, the Company will calculate any under or over-recoveries of Deferred Incremental Revenue during the Deferral Period and include any such true-up amounts in the Company's Q2 Gas Cost Adjustment to be filed in March 2026 and recovered over the Q2 period. N

DEFINITIONS: N

The terms used in this tariff have the following meanings unless otherwise noted. N

Decision. Decision No. RXX-XXXX issued in Proceeding No. 24AL-XXXXG, the Company's 2024 natural gas rate case proceeding. N

Deferred Incremental Revenue. The amount of incremental revenue for the Deferral Period, which will be deferred and recorded in a regulatory asset, with a weighted average cost of capital return on the asset, as approved by the Decision. N

Deferral Period. The period November 1, 2024 through February 14, 2025. N

Incremental Revenue Recovery Period. February 15, 2025 through February 14, 2026. N

Rate Effective Date. November 1, 2024. N

Rate Implementation Date. February 15, 2025. N

RDS Amount. The RDS percent applied to each rate schedule reflecting the result of the relevant RDS calculation applied during the Incremental Revenue Recovery Period. N

RDS CALCULATION N

The amount of Deferred Incremental Revenue will be determined for each rate schedule by multiplying the rates approved by the Decision by actual monthly billing determinants from the Deferral Period, as available, then subtracting the actual base rate revenues collected from each rate schedule during the Deferral Period. The Company's authorized pre-tax weighted average cost of capital will be applied as interest to the Deferred Incremental Revenue. The Deferred Incremental Revenue will also include the initial first period of the Revenue Stability Mechanism amount for Schedules RG and CSG stemming from the November 2024 through January 2025 period. The total revenue requirement N

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 49B

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No. 49B

NATURAL GAS RATES
REVENUE DEFERRAL SURCHARGE N

RDS CALCULATION - Cont. N

for each rate schedule will then be divided by the forecasted base rate revenues for each rate schedule during the Incremental Revenue Recovery Period. N N N

TRUE-UP N
After conclusion of the Incremental Revenue Recovery Period, the amount of the Deferred Incremental Revenue will be subject to a final true-up by rate schedule based on actual billing determinants during the Incremental Revenue Recovery Period, and, as required by the Decision, will be applied by rate schedule to the Gas Cost Adjustment ("GCA"), beginning with the GCA to become effective on April 1, 2026. N N N N N N

RATE TABLE N

For the Incremental Revenue Recovery Period, the charge for natural gas service calculated under the Company's natural gas base rate schedules, exclusive of any GRSAs, shall be adjusted by the percentages listed below. N N N

Rate Schedule	**Revenue Deferral Surcharge**	
Residential Service		N
RG	10.14%	N
RGL	9.96%	N
Commercial & Industrial Sales Service		N
CSG	9.06%	N
CLG	9.29%	N
CGL	10.22%	N
IG	10.44%	N
Gas Transportation Service		N
TFS	10.46%	N
TFL	9.40%	N
TI	9.79%	N

ADVICE LETTER NUMBER ____________

ISSUE DATE January 29, 2024

DECISION NUMBER ____________

REGIONAL VICE PRESIDENT
Regulatory and Pricing

EFFECTIVE DATE ____________

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 50A

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No. 50A

NATURAL GAS RATES
GAS COST ADJUSTMENT

DEFINITIONS - Cont'd

Average Gas Storage Inventory Balance. The annual average of the forecasted monthly average gas storage inventory balances for the GCA Effective Period.

Base Rate(s). The Company's currently effective rates for sales gas and gas transportation service as authorized by the Commission in the Company's last general rate case.

Current Gas Cost. A rate component of the GCA, expressed in mils per dekatherm ($0.001 per Dth), which is the sum of the Gas Commodity Cost, Upstream Service Cost and the Gas Storage Inventory Cost projected to be incurred by the Company during the GCA Effective Period divided by the applicable Forecasted Sales Gas Quantity.

Deferred Gas Cost. Gas costs accumulated in the Company's Account No. 191, which can be over- or under-recoveries, calculated by subtracting Recovered Gas Cost from Actual Gas Cost, as of the end of the month that is one month prior to the effective date of the GCA, adjusted for unbilled revenues, and including: (1) storage adjustments; (2) other costs authorized by the Public Utilities Commission; (3) Interest on Account No. 191 Balance, as authorized by the Public Utilities Commission; (4) the net Daily Imbalance Charges from transportation customers under the Shipper Daily Balancing Option; ~~and~~ (5) the net Monthly Cashouts from transportation customers; and (6) true up of any over- or under-recoveries from the Revenue Deferral Surcharge in place for the 12 months beginning February 15, 2025. The Deferred costs will be offset by Unauthorized Overrun Penalties collected from customers. T T T T

Deferred Gas Reserve Tracker. Amounts will include a separate gas reserve component tracked in account No. 191 based on actual GCA costs that have risen above or fallen below a defined threshold. The threshold triggering use of this account consists of an upper limit of 180 percent of the average GCA over the last five calendar years less any current EGCRR rate and a lower limit of 80 percent of the average GCA over the last five calendar years. Any changes to the upper or lower limit will be effective in the third quarter GCA annually. If the GCA rate exceeds the upper dekatherm amount of the range the resulting gas reserve component balance, the amount above the upper limit will be included in the Deferred Gas Reserve Tracker, and if the GCA rate is under the lower dekatherm rate end of the range the amount below the lower limit may be included in the Deferred Gas Reserve Tracker. This tracker will be adjusted at the time the GCA rate is adjusted to ensure the rate remains in the defined range until the next filing. The Deferred Gas Reserve Tracker includes symmetrical interest on both under-recovered and over-recovered balances.

ADVICE LETTER NUMBER 1024

DECISION NUMBER C23-0796

REGIONAL VICE PRESIDENT, Regulatory and Pricing

ISSUE DATE December 11, 2023

EFFECTIVE DATE December 14, 2023

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 50B

P.O. Box 840
Denver, CO 80201-0840

Cancels Sheet No. 50B

NATURAL GAS RATES
GAS COST ADJUSTMENT

DEFINITIONS - Cont'd

Forecasted Sales Gas Quantity. The quantity of gas commodity projected to be sold by the Company during the applicable GCA Effective Period, based upon the historic quantity of gas commodity sales, adjusted to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data and anticipated changes, except that for the Deferred Gas Cost rate component calculation, the Forecasted Sales Gas Quantity shall be the gas commodity projected to be sold during the 12-month period applicable to the Company's quarterly GCA application effective October 1. M M M M

Gas Commodity Cost. The total cost of the natural gas commodity that includes each of the following costs, as determined for each month within the GCA Effective Period: (1) the NYMEX Settlement Price as of the first business day of the month prior to the GCA Effective Period, adjusted for the basis differentials between the monthly NYMEX Settlement Price, which is based upon deliveries at the Henry Hub, and the respective indexes applicable to the various areas where the Company purchases its gas supplies, multiplied by the purchase volumes for each corresponding month within the GCA Effective Period; (2) the monthly reservation fees or demand charges payable to gas sellers for making firm quantities of gas available for sale to Company irrespective of the commodity volume actually delivered (gas demand costs); (3) the physical fixed price purchases; (4) appropriate adjustments for storage gas injections and withdrawals; and (5) the gas price management costs.

Gas Cost Adjustment ("GCA"). The tariff mechanism by which a gas rate is adjusted on an expedited basis to reflect increases or decreases in rate components, such as the Deferred Gas Cost, Gas Commodity Cost, Upstream Service Cost and Gas Storage Inventory Cost.

GCA Effective Period. The period of time that the GCA rate change is intended to be in effect. The GCA Effective Period for the Gas Commodity Cost, and Deferred Gas Cost, components of the GCA rate is the three-month calendar quarter, except that for purposes of an interim GCA, the GCA Effective Period for the Gas Commodity Cost is either two months or one month, depending on the number of months remaining before the GCA Effective Period for the next regular quarterly GCA. The GCA Effective Period for the Upstream Service Cost and Gas Storage Inventory Cost components of the GCA rate is typically twelve months, from October 1 through September 30, except that for purposes of a regular quarterly GCA, the GCA Effective Period for the Upstream Service Cost and Gas Storage Inventory Cost components of the GCA rate is the remainder of such twelve-month period.

ADVICE LETTER NUMBER

ISSUE DATE January 29, 2024

DECISION NUMBER

REGIONAL VICE PRESIDENT,
Regulatory and Pricing

EFFECTIVE DATE

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 50C

P.O. Box 840
Denver, CO 80201-0840

Cancels Sheet No. 50C

NATURAL GAS RATES
GAS COST ADJUSTMENT

DEFINITIONS - Cont'd

Gas Storage Inventory Cost. A rate component of the GCA, expressed in mils per dekatherm ($0.001 per Dth) which is the return applied to the Average Gas Storage Inventory Balance divided by the Forecasted Sales Gas Quantity. The return applied to the Average Gas Storage Inventory Balance shall be based on the Company's weighted average cost of capital ~~monthly interest rate equal to the average of the daily rates for Commercial Paper, Financial, 3-Month rates, published by the United States Federal Reserve H.15 report (http://www.federalreserve.gov/releases/h15/data.htm)~~. The return will be adjusted for income taxes before being multiplied by the Average Gas Storage Inventory. T T T T

Interest on Account No. 191 Balance. For amounts outside of the Deferred Gas Reserve Tracker, interest at a rate equal to the interest rate paid on customer deposits as set forth in the General Terms and Conditions will be applied to the Account No. 191 Deferred Gas Cost Balance on an average monthly basis. The disposition of any net interest on over- or under-recovered gas costs shall be as directed by orders of the Public Utilities Commission in Docket Nos. 02A-267G and 08A-095G.

Recovered Gas Cost. The gas costs recovered by the Company, which shall be calculated by applying the GCA rate to actual sales quantities billed for the period the GCA rate was in effect.

Upstream Service Cost. The total cost of all transmission, gathering, compression, balancing, treating, processing storage and like services performed by others under contract with the Company for the purpose of effectuating delivery of gas commodity to the Company's jurisdictional natural gas facilities.

CURRENT GAS COST RATE DETERMINATION

Current Gas Cost shall be calculated to the nearest mil per Dth according to the following formula:

Current Gas Cost = A + B + C

A = Gas Commodity Cost
B = Upstream Service Cost
C = Gas Storage Inventory Cost

(Continued on Sheet No. 50D)

ADVICE LETTER NUMBER ______

ISSUE DATE January 29, 2024

DECISION NUMBER ______

REGIONAL VICE PRESIDENT, Regulatory and Pricing

EFFECTIVE DATE

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 52

P.O. Box 840
Denver, CO 80201-0840

Cancels Sheet No. 52

NATURAL GAS RATES

REVENUE STABILITY MECHANISM ("RSM") Adjustment N

APPLICABILITY N

Rate Schedules RG and CSG are subject to a Revenue Stability Mechanism (RSM). The RSM factors for the applicable rate schedules will be applied through a $/therm charge. N

DEFINITIONS N

ACTUAL MARGIN PER CUSTOMER CLASS (AMPCC) N

The AMPCC is the Current Period base rate revenues collected by the Company and not adjusted for weather, inclusive of General Rate Schedule Adjustments (GRSA or GRSA-P). Calculated separately for Schedules RG and CSG. N

TARGET NORMALIZED MARGIN PER CUSTOMER CLASS (TNMPCC) N

The TNMPCC is calculated using test year base rate revenues established by the Commission in a previous rate case or other applicable proceeding, by using the Base Rate Charges and GRSAs or GRSA-P factors that were in place during the Current Period multiplied by the weather normalized billing determinants for the Current Period. Calculated separately for Schedules RG and CSG. N

CURRENT PERIOD N

The three (3) month period for which the RSM is being calculated. The initial Current Period shall be the November 2024 through January 2025 period, and subsequent periods will be every 3 months thereafter. N

DEMAND-SIDE MANAGEMENT ACKNOWLEDGEMENT OF LOST REVENUE (DSM-ALR) N

The Commission approved acknowledgement of lost revenue, as defined on Sheet No. 42A, that is in place for the Current Period. The Company will use the Commission approved DSM-ALR from the most recent DSM plan as the basis for an initial estimate, and any over- or under-recoveries will be included as part of the DSM-ALR True-Up. Calculated separately for Schedules RG and CSG. N

RECOVERY TIMEFRAME N

The timeframe over which the RSM factors will be in place. The RSM will be billed over a 12-month period. The initial Recovery Timeframe will be from July 1, 2025 through June 30, 2026, which will reflect the second full period of the RSM. The initial first period will be recovered through the Revenue Deferral Surcharge. N

RSM AMOUNT N

The difference between the TNMPCC and the AMPCC, less the Variable Operating Costs, plus Current Period DSM-ALR, plus the RSM True-Up amount (if any) and the DSM-ALR True-up amount (if any), either positive or negative. Calculated separately for Schedules RG and CSG. N

ADVICE LETTER NUMBER ____

ISSUE DATE January 29, 2024

DECISION NUMBER ____

VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE ____

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 52A

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No. 52A

NATURAL GAS RATES

REVENUE STABILITY MECHANISM ADJUSTMENT N

DEFINITIONS – Cont'd N

RSM TRUE-UP N

The over-recovery or under-recovery of RSM amounts after the 12 months of billing is complete. The RSM True-up value consists of the difference between the revenue the RSM factor was designed to collect (the Current Period RSM Amount) and the actual revenue collected through the RSM factor during the Recovery Timeframe. Calculated separately for Schedules RG and CSG. N

DSM-ALR TRUE-UP N

The difference between the DSM-ALR forecast and the actual DSM-ALR for the Calendar Year, included as part of the third period RSM Amount. Calculated separately for Schedules RG and CSG. N

VARIABLE OPERATING COSTS N

The costs associated with FERC Accounts 755, 819, 854, and 873 that are included in the Base Rate Usage Charges for Schedules RG and CSG from the previous rate case or other applicable proceeding. Calculated separately for Schedules RG and CSG. N

REVENUE STABILITY MECHANISM RATE CALCULATIONS N

Calculated separately for Schedules RG and CSG. N

RSM Amount = TNMPCC - AMPCC - Variable Operating Costs - DSM-ALR +/- RSM True Up +/- DSM-ALR True Up N

Current Period RSM Rate = RSM Amount ÷ Forecasted Volume for Recovery Timeframe (therms) N

Total RSM Rate = The summation of the Current Period RSM Rate and the prior three periods' RSM Rate, if applicable. N

ADVICE LETTER NUMBER

ISSUE DATE January 29, 2024

DECISION NUMBER

VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

Sheet No. 52B

Cancels
Sheet No. 52B

NATURAL GAS RATES
REVENUE STABILITY MECHANISM ADJUSTMENT N

Rate Schedule	Billing Units	RSM Rates	
RG	Therm	$0.XXXXX	N
CSG	Therm	$0.XXXXX	N

ADVICE LETTER NUMBER ____________

ISSUE DATE January 29, 2024

DECISION NUMBER ____________

VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE ____________

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 70E

P.O. Box 840
Denver, CO 80201-0840

Cancels Sheet No. 70E

NATURAL GAS RATES
QUALITY OF SERVICE PLAN (QSP)

QSP PERFORMANCE BASELINE

QSP APPROVAL PERIOD: January 1, 2022 through December 31, 2026 C

SAFETY:

a) Damage Prevention

Objective: Lower damages/1000 locates

Penalty: $250,000

~~2022 Performance Baseline: Damages exceed 2.02 damages/1000 locates~~ T

Performance Baseline~~ (beginning January 1, 2023)~~: Damages exceed 1.47 damages/1000 locates T

b) Emergency Response

Objective: Improve responsiveness in potential emergency situations

Penalty: $250,000

~~2022 Performance Baseline: Response falls below 76.1 percent within 60 minutes~~ T T

Performance Baseline~~ (beginning January 1, 2023)~~: Response falls below 95 percent within 60 minutes T

RELIABILITY:

a) Grade 2 Leak Repair Time

Objective: Decrease the amount of methane released into environment

Penalty: $250,000

~~2022 Performance Baseline: Repair time exceeds 63.3 days~~ T

Performance Baseline~~ (beginning January 1, 2023)~~: Repair time exceeds 52 days T

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. R86

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No. R86

RULES AND REGULATIONS

NATURAL GAS SERVICE

DISTRIBUTION EXTENSION POLICY

STANDARD CONSTRUCTION COSTS AND CREDITS

Construction Costs	
Residential On-Site Distribution Extension Per Lot Cost	$ 1,741~~688~~
Residential Service Lateral Extension < 100 Ft. Cost	$ 1,521
Residential Service Lateral >100ft. Cost Per Foot	$ 9.46
Per Meter Set Costs (customer share)	
Residential Per Meter Set Cost	$ 291
CSG Per Meter Set Cost	$ 1,690
All Other Per Meter Set Cost	$ 6,338

Off-Site Distribution Main Extension Credit (not available for applications dated on or after November 1, 2023 unless terminated earlier pursuant to Commission decision)

Off-Site Distribution Main Extension Credit	28.00%

The above costs and credits may be recalculated and revised from time to time as determined necessary by the Company based on the same method(s) as approved by the Commission. An additional charge may be applicable for special items, including without limitation any Applicant-associated delays; obstructions; permit fees; or any special item required to meet construction conditions, including but not limited to frost conditions and rock conditions.

The Off-Site Distribution Main Extension Credit is a twenty-eight percent (28%) credit applied to an Applicant's Construction Costs for an Off-Site Distribution Main Extension. In the event that excess Construction Allowance is awarded to an Off-Site Distribution Main Extension, this credit shall be applied after the Construction Allowance has been applied. The Off-Site Distribution Main Extension Credit is not available for applications dated on or after November 1, 2023 unless terminated earlier pursuant to Commission decision.

ADVICE LETTER NUMBER ____

ISSUE DATE January 29, 2024

DECISION NUMBER ____

REGIONAL VICE PRESIDENT
Regulatory and Pricing

EFFECTIVE DATE ____

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

Sheet No. R88

Cancels
Sheet No. R88

RULES AND REGULATIONS

NATURAL GAS SERVICE

DISTRIBUTION EXTENSION POLICY

ON-SITE STANDARD CONSTRUCTION COSTS AND CONSTRUCTION ALLOWANCE WORKSHEET

	Per Lot Standard Cost $	Construction Allowance $	Customer Responsibility $
Gas	$ 1,741~~688~~ [1]	$ (331) [2]	$ 1,410~~357~~

[1] Standard Construction Costs and Credits - On-Site Distribution Extension Per Lot Cost
[2] Gas Residential Construction Allowance - Distribution Main Portion

An additional charge may be applicable for special items, including without limitation any Applicant-associated delays; obstructions; permit fees; or any special item required to meet construction conditions, including but not limited to frost conditions and rock conditions.

January 31, 2025
Compliance Advice Letter Filing to:
-Place into effect the approved Rates & RDS
-Initial Period 1 of RSM placed into RDS
- Rates effective date of February 15, 2025
(Note: EGCRR rate ends February 14, 2025)

February 2026
Compliance Advice Letter Filing to:
-End RDS as of February 15, 2026

March 2026
Q2 2026 GCA Filing to:
-Incorporate any applicable true-up of RDS revenue to Deferred Incremental Revenue

Revenue Deferral Surcharge ("RDS")

<-----------Deferral Period----------->
November 2024 - February 14, 2025

<----RDS Billed---->
12 months

October 2024
Compliance Advice Letter Filing to implement:
-GRSA
-RDS
-RSM
-Other tariff changes

November 2024
Rate Effective Date
-No change to customer base rates
-PSCo begins to accrue incremental revenue
-RSM effective

September 1, 2025 (Optional)
RDS Adjustment beginning in October 2025 if actuals for RDS are +/- 20% from forecast

Revenue Stability Mechanism ("RSM")*

Initial RSM Time Period 1	RSM Time Period 2	RSM Time Period 3	RSM Time Period 4	
November 2024 - January 2025	February 2025 - April 2025	May 2025 - July 2025	August 2025 - October 2025	
January 31, 2025 Period 1 RSM adjustment included in the RDS that will be billed over 12 months	**June 2025 Filing** Period 2 RSM adjustment billed July 2025 - June 2026	**September 2025 Filing** Period 3 RSM adjustment billed October 2025 - September 2026	**December 2025 Filing** Period 4 RSM adjustment billed January 2026 - December 2026	Each Period (excluding initial Period 1) will have a true-up included in the Periodic RSM adjustments following the 12-months of billing

*RSM would continue on same annual schedule (excluding the initial Period 1 that will be placed into the RDS)