BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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| IN THE MATTER OF THE APPLICATION OF ENBRIDGE GAS UTAH TO INCREASE DISTRIBUTION RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS | Docket No. 25-057-06 |

**DIRECT TESTIMONY OF**

**KELLY B MENDENHALL FOR**

**ENBRIDGE GAS UTAH**

May 1, 2025

**EGU Exhibit 1.0**

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## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Kelly B Mendenhall. My business address is 333 South State Street, Salt Lake City, Utah.

**Q. By whom are you employed and what is your position?**

A. I am employed by Questar Gas Company dba Enbridge Gas Utah ("Enbridge Gas", "EGU" or the "Company") as Director of Regulatory and Pricing. I am responsible for state regulatory matters for Enbridge Gas in Utah.

**Q. What are your qualifications to testify in this proceeding?**

A. I have listed my qualifications in EGU Exhibit 1.01.

**Q. Attached to your written testimony are EGU Exhibits 1.01 through 1.07. Were these prepared by you or under your direction?**

A. Yes, unless otherwise stated. If otherwise indicated, they are true and correct copies of what they purport to be.

**Q. What is the purpose of your testimony in this Docket?**

A. My testimony provides an overview of merger commitments agreed to in Docket No. 23-057-16 and addresses how the Company has complied with these commitments. My testimony also discusses the test period that the Company believes best reflects the rate-effective period, and I introduce the Company's witnesses who support the proposed return on equity of 10.6% and overall cost of capital of 7.61%, the proposed test period, the revenue requirement, the cost-of-service and rate-design proposals in this docket, as well as the proposed changes to the Company's Utah Tariff No. 700 ("Tariff").

## II. INTRODUCTION OF WITNESSES

**Q. Please identify the Company's witnesses?**

A. Ms. Jennifer Nelson, a Vice President at Concentric Advisors, will provide testimony supporting the Company's capital structure, cost of debt, cost of equity, and overall rate of return.

Mr. Warren Reinisch, Director of Treasury, will provide testimony supporting the Company's proposed actual 2026 capital structure.

Mr. Jordan K. Stephenson, Manager of Regulation for EGU, provides testimony supporting the proposed test period and showing that the selected future test period best reflects the conditions that will exist during the rate-effective period. Mr. Stephenson also provides the revenue requirement for the proposed test period.

Mr. Austin C. Summers, Manager of Regulation for the Company, provides testimony supporting the Company's cost-of-service model and rate design for all rate classes.

Mr. David C. Landward, Regulatory Consultant, provides testimony that explains and proposes changes to the weather normalization adjustment.

Mr. Jordan Parks, Regulatory Analyst III, provides a summary of the Tariff changes proposed by the Company.

## III. BACKGROUND

**Q. Can you summarize the relief the Company is requesting?**

A. Yes. As demonstrated in my testimony and the other supporting Company testimony, the Company has identified a $115 million revenue deficiency and seeks a rate increase to address that deficiency.

**Q. Are there additional drivers that are causing the Company to seek rate relief in this docket?**

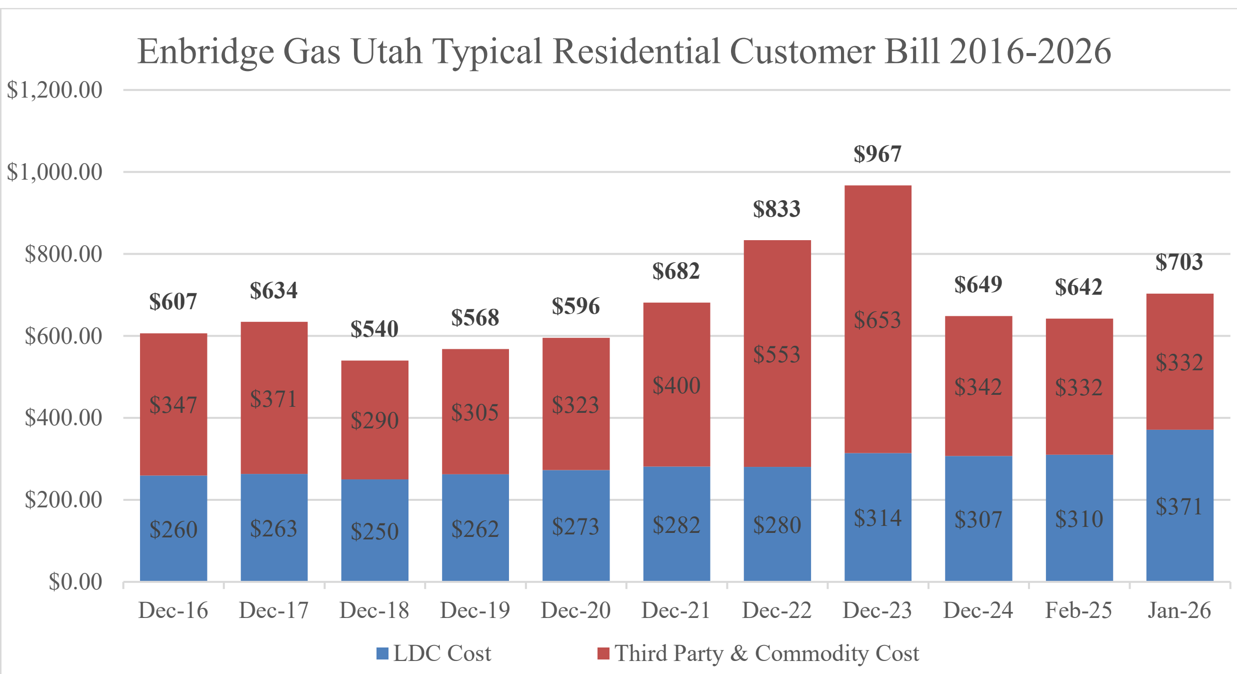
A. Yes. The projected 2026 rate base is $3.2 billion, about $664 million higher than the 2023 test period rate base in the 2022 general rate case. The return, depreciation and property taxes associated with this rate base are the main drivers for the requested increase.

**Q. What impact does this proposal have on customers?**

A. A typical residential customer using 70 Dths would see about a $61 or 9.5% annual increase if this request is approved.

**Q. What impact does this increase have on customer bills when compared to historical periods?**

A. The annual bill for a typical customer is provided in the table below:




As the chart shows, the typical residential customer would pay $703 per year beginning January 1, 2026 if the Company's proposal is approved. Comparing the proposal to prior years, the typical bill has increased at a rate lower than inflation over the last ten years.

## IV. TEST PERIOD

**Q. What is the Company's proposed test period in the rate case?**

A. The Company is proposing an average 13-month forecasted test period for the year ending December 31, 2026. Mr. Stephenson discusses how the conditions the Company expects during the proposed test period best reflects the conditions the Company will encounter during the rate-effective period.

**Q. What evidence can the Company provide that its forecasted test period is reliable?**

A. With respect to Operation and Maintenance ("O&M") expense, Mr. Stephenson's EGU Exhibit 4.08 shows that for the last five years the Company's actual O&M expense have been, on average, 2% higher than forecasted. Overall, the Company's budgeting process has been accurate and reliable.

**Q. Have the Company's capital budget forecasts been accurate?**

A. Yes. Although the projections provided in November of each year require forward-looking assumptions concerning complex situations, the Company is pleased to have been within 2.7% of cumulative budgeted annual spending since 2020.

| | Budget | Actual | Variance |
|---|---|---|---|
| 2020 | $338,438,948 | $328,672,812 | -$9,766,136 |
| 2021 | $362,790,914 | $365,270,888 | $2,479,974 |
| 2022 | $357,773,923 | $364,812,343 | $7,038,420 |
| 2023 | $299,616,055 | $337,315,348 | $37,699,293 |
| 2024 | $321,516,917 | $329,171,632 | $7,654,715 |
| Average | $336,027,351 | $345,048,605 | $9,021,253 |
| % Variance | | | 102.68% |

## V. QUESTAR GAS CHANGE OF OWNERSHIP

**Q. On May 16, 2024, the Commission approved a stipulation filed in the sale of Fall West Holdco, LLC to Enbridge Quail Holding, LLC. The stipulation contained several commitments with respect to the sale and Commission approval of that sale. Can you provide a status update on the Company's compliance with these commitments?**

A. Yes. As I discuss further, the Company has complied with the terms of the stipulation and will continue to perform its obligations in the stipulation. The Company filed its first integration progress report on April 14, 2025. I have attached that report as EGU Exhibit 1.02. Per the terms of the stipulation, this report will be filed quarterly until the conclusion of the Company's next general rate case.

**Q. Please highlight some of the more substantive commitments contained in the stipulation.**

A. Many of the 36 commitments focused on compliance with existing rules, orders, etc. While the Company is complying with all of the commitments, in the table below, I have focused on some of the new commitments that I expect would be of particular interest to the Commission:

| Merger Stipulation Provision Number | Provision Summary |
|---|---|
| 7b | Gas Supply Sourcing |
| 8 | Customer Communications Plan |
| 9.c.i. | Infrastructure Replacement Tracker cap |
| 9cii | Infrastructure Replacement Tracker ("IRT") credit |
| 11 | Transaction Costs |
| 13c | Operating and Maintenance Expense per customer |

| Merger Stipulation Provision Number | Provision Summary |
|---|---|
| 17a | Charitable Contributions |
| 23d | Customer Satisfaction Standards |

**A. *Merger Stipulation Provision 7b – Gas Supply Sourcing***

**Q. What was the specific merger commitment related to reporting gas supply sourcing?**

A. Paragraph 7b of the Merger Stipulation states: "In the 2024 Integrated Resource Plan ("IRP"), Questar Gas will provide historical information specifying the volumes and the location(s) of its gas supply purchases for the prior three IRP years. In each IRP thereafter, Questar Gas will update such information by including comparable information for the next succeeding year. Questar Gas will, to the extent known to Questar Gas, provide information on the origin of gas purchased at each identified purchase point and the location of Wexpro Production utilized during each year."

**Q. How has EGU complied with this commitment?**

A. The Company complied with this request in its 2024 IRP filing in Docket No. 24-057-04. The requested information was provided in a February 15, 2024, technical conference and again in Table 8-5 and Table 9-3 in the actual document.[1] As the tables show, all of the natural gas used by Enbridge Gas Utah customers is sourced from Utah, Wyoming or Colorado.

[1] pscdocs.utah.gov/gas/24docs/2405704/334287EGUIRPJun12024toMay3120256-14-2024.pdf.

### *B. Merger Stipulation Provision 8 – Customer Communication plan*

**Q. What was the specific merger commitment related to the customer communication plan?**

A. Paragraph 8 of the Merger Stipulation states: "8. EQ Holdings will develop and provide to the Division and the OCS a plan identifying how it intends to communicate the change in ownership of Questar Gas from Dominion Energy to EQ Holdings. Upon approval of the Application in this matter and until such communications plan concludes, Questar Gas will periodically meet with the OCS and the Division to share details, and receive feedback, about the communications plan."

**Q. How has EGU complied with this commitment?**

A. The Company held meetings with the OCS and DPU on May 7, 2024. An attachment of the communications plan that was shared at that meeting is provided in EGU Exhibit 1.02, beginning on page 9. The Company appreciates the engagement and feedback provided by the OCS and DPU. An additional follow-up email with additional information was shared on October 28, 2024. This communications plan and rebranding update is attached in pages 30-45 of EGU Exhibit 1.02. As of today, the communication plan with respect to the name change is complete and all customer communications channels have been moved over to an Enbridge-only platform. The overall feedback the Company has received has been positive and it has been considered a success.

**Q. In addition to changing the name on all customer communications channels will Enbridge be making any other notable changes to its communications plan to customers?**

A. Yes. In 2018, Dominion Products and Services entered into an agreement with Homeserve Inc. to allow Homeserve to use the Dominion logo on Homeserve mailings to customers. Enbridge has chosen to discontinue this relationship in Utah. Enbridge has not allowed Homeserve to use the Enbridge logo or name on any mailings to Utah customers and, effective December 31, 2025, all legacy Homeserve customers currently receiving Homeserve charges on an Enbridge Gas Utah bill will be moved off the Enbridge Gas Utah bill and be billed by Homeserve directly if they choose to continue to receive Homeserve warranty services.

### *C. Merger Stipulation Provision 9ci – Infrastructure Replacement cap*

**Q. Please provide more detail about the Infrastructure Replacement cap?**

A. Paragraph 9c.i. of the Merger Stipulation states: **"**Questar Gas will not propose an increase to the current Commission approved Infrastructure Replacement Investment level of $84.7 million, adjusted annually based on the GDP deflator index, for Questar Gas's next two general rate cases."

**Q. Has Enbridge complied with this commitment?**

A. Yes. The Company is not proposing any changes to the infrastructure rate adjustment tariff in this case.

### *D. Merger Stipulation Provision 9cii – Infrastructure Replacement credit*

**Q. Please provide more detail about the Infrastructure Replacement credit?**

A. Paragraph 9cii of the Merger Stipulation states: "In Questar Gas's next Infrastructure Replacement tracker rate adjustment filing with the Commission in 2024, Questar Gas will apply a $275,000 credit to the revenue requirement calculation, effectively reducing the revenue collection from Questar Gas's Customers through the surcharge by such amount for one year, as calculated pursuant to Questar Gas's Tariff PSCU 600, Section 2.07."

**Q. Has Enbridge complied with this commitment?**

A. Yes. In Docket Nos. 24-057-21 and 24-057-24, the Company included the $275,000 credit in its revenue requirement calculation. The credit took effect on November 1, 2024, and will remain in effect until at least November 1, 2025.

### *E. Merger Stipulation Provision 11 – Transaction Costs*

**Q. Please provide more detail about the provision related to transaction costs?**

A. Provision 11 of the Merger Stipulation states: "Transaction costs associated with the Transaction will not be recovered through the rates of Questar Gas or recovered through charges from affiliated companies of Enbridge or EQ Holdings to Questar Gas. Transaction costs are defined as: (i) legal, consulting, or other professional advisor costs to initiate, prepare, consummate, and implement Transaction, including obtaining regulatory approvals; (ii) rebranding costs, including websites, advertising, vehicles, signage, printing, and stationary; (iii) executive change in control costs (severance payments and accelerated vesting of share-based compensation); and (iv) financing cost related to the Transaction, including bridge and permanent financing costs, executive retention payments, costs associated with shareholder meetings, and proxy statement related to Transaction approval."

**Q. Has Enbridge complied with this commitment?**

A. Yes. There were costs incurred by Enbridge at the parent level and costs incurred by Questar Gas. The costs borne by Enbridge were kept in the Enbridge accounting system and not included as part of Questar Gas costs. The costs incurred by Questar Gas have been booked below the line and are included on page 46 of EGU Exhibit 1.02.

### *F. Merger Stipulation Provision 13c – Operating and Maintenance Administrative and General Expense/Customer*

**Q. What was the commitment related to OMAG/Customer expense?**

A. Paragraph 13c of the Merger Stipulation states: "Questar Gas will not seek recovery in its next two general rate cases for any increase in the aggregate total inflation adjusted Operating, Maintenance, Administrative, and General Expenses (excluding energy efficiency, bad debt, and pension costs) cost per customer over the cost per customer for such items for the 12 months ended December 2023, unless Questar Gas can demonstrate that such increase was not caused by the transaction (for example supply chain cost increases or cost increases caused by changes in accounting policy or legal and regulatory requirements). The amount for such items per customer for the 12 months ended December 2023 was $125.89 (2023 Baseline Cost Per Customer), as calculated in Attachment 1 to this Commitment Matrix. Questar Gas will increase the 2023 Baseline Cost Per Customer annually (as increased at the end of each year, the Adjusted Baseline Cost Per Customer) for inflation, if positive over the prior year, by the inflation factor of the U.S. Consumer Price Index – All Urban Consumers and compare the Adjusted Baseline Cost Per Customer to Questar Gas's actual per customer cost for Operating, Maintenance, Administrative, and General Expenses (excluding energy efficiency, bad debt, and pension costs) in the Integration Progress Report referred to in Commitment No. 36."

**Q. What is the adjusted baseline for 2024?**

A. The calculated cap and actual 2024 O&M expenses are shown in the table below:

| Period | Operating and Maintenance per customer |
|---|---|
| 2023 Baseline | $125.89 |
| 2024 Adjusted for Inflation Baseline | $130.86 |
| 2024 Actual | $127.05 |

As the table shows, the actual 2024 O&M per customer of $127.05 was well below the inflation adjusted baseline of $130.86. The detailed calculation can be found on page 47 of EGU Exhibit 1.02.

### *G. Merger Stipulation Provision 17a – Charitable Donations*

**Q. What commitments did the Company make with respect to charitable giving?**

A. Paragraph 17a of the Merger Stipulation states: "Questar Gas's charitable contributions were $1,445,602 in 2022. In addition, Questar Gas disbursed $217,500 to various arts and education organizations through a trust. Commencing in the first calendar year in which the closing occurs, EQ Holdings will increase Questar Gas's charitable contributions by $175,000 per year for three years. The continuation of these contributions, with the incremental support, will benefit the local communities by helping to ensure continuity in efforts to support local charitable causes. Also, after the closing, the arts and education trust will be liquidated and the assets in the trust (approximately $3 million) will be given to the various arts and education organizations."

**Q. Has the Company complied with this commitment?**

A. Yes. In 2024, the Company donated $1,728,460 to charitable causes in Utah and Wyoming, an amount that was $107,858 or 7% higher than the original commitment of $1,620,602. Additionally, the arts and education trust was liquidated on June 24, 2024 and $4,036,691 was given to Utah and Wyoming universities and arts organizations.

***H. Merger Stipulation Provision 23 – Customer Service Metrics***

**Q. What was Enbridge's commitment related to customer service metrics?**

A. Paragraph 23 of the Merger Stipulation states: "Following closing of the Transaction, Questar Gas will work with the Division and the OCS on a collaborative basis and update the Customer Satisfaction Standards, considering recent historical results. Questar Gas will report quarterly on its performance relative to the Customer Satisfaction Standards. Quarterly reporting will continue through completion of the second general rate case filing following closing of the Transaction. If service levels fall short of the agreed "goals" identified in the updated Customer Satisfaction Standards, Questar Gas will file a remediation plan with the Commission explaining the undertakings Questar Gas will implement to improve and restore service to meet these goals."

**Q. Is the Company complying with this commitment?**

A. Yes.

**Q. Please provide an update on this commitment.**

A. The Company met with the DPU and OCS as well as the Office of Consumer Advocate in Wyoming. Based on those discussions, the Company is proposing, and the parties have agreed, to change five metrics going forward.

The purpose of the metrics is to create a baseline that the Company's performance can be tracked against over time. The proposed changes are shown in the table below.

| | Previous Metric | Proposed Metric | 18-Month Average |
|---|---|---|---|
| How satisfied are you with the product and services you receive | 6.0 | 5.9 | 5.94 |
| Callers that hang up after menu choice is made | < 2% | < 5% | 4.21% |
| Percentage of calls answered within 60 seconds after customer chooses menu option | 85% | 75% | 78.9% |
| Average wait for customer after menu selection to speak to an agent | < 45 sec | < 85 sec | 71 sec |
| Amount of time talking with customer to complete request | < 5 min | < 6 min | 7.44 min |

**Q. Please provide some background on why you have changed the survey metric "How satisfied are you with the product and services you receive?"**

A. This metric is being changed from 6.0 to 5.9 to reflect the most recent average of this result. While it isn't a large difference, we felt it was important to establish an accurate baseline.

**Q. Please provide background on why you are proposing to change the metric titled "percent of callers that hang up after menu choice is made."**

A. Over the past several years, the Company has created options for customers to resolve their inquiries. Some of these include interactive voice response, online account management, and a mobile app option. These channels allow customers to perform simple tasks themselves, such as turn on/off service or check account balances, rather than having to speak with a representative. As a result, because more customers can resolve their issue without speaking to a customer care agent, more customers hang up after going through the call menu than they did in 2016, even though those customers are not hanging up due to a delay in speaking to a representative. While the implementation of these options has allowed for quicker resolution of easier tasks, it means that the remainder of calls to the call center involve more complex issues that take time to resolve. The change in this metric is intended to set a proper baseline for the calls that are addressed through a call center representative.

**Q. Did the call complexity cause you to also change the other three metrics related to call wait times, the amount of time talking with customer, and time to complete a request?**

A. Yes, the call complexity has a large impact on these metrics. Additionally, over the past several years, competition for call center representatives has increased. This has caused much turnover and difficulty in maintaining a fully staffed call center. This turnover results in less experienced representatives answering phone calls, which also contributes to the longer call times. In addition to call complexity and less experienced call center employees, there has been a large focus over the last few years on first call resolution that increases talk time but also increases customer satisfaction by resolving customer issues on the first call and eliminates subsequent calls by customers. As a result of these changes, the "Percentage of calls answered within 60 seconds after customer chooses menu option" has been changed from 85% to 75%. Also, the metric "average wait" for customer after menu selection to speak to an agent has been changed from <45 seconds to <85 seconds. Finally, the "Amount of time talking with customer to complete request" metric has been increased from 5 minutes to 6 minutes to reflect the increased complexity of the calls.

**Q. Did the parties discuss any new metrics to measure the use of these new self-serve options by customers?**

A. Yes, going forward the parties agreed to add a new metric to track self-serve interactions. This will reflect the number of customers resolving inquiries themselves over time through the options discussed above. A summary of this metric for 2024 is shown in the table below:

| Q1 2024 | Q2 2024 | Q3 2024 | Q4 2024 | 2024 Average |
|---|---|---|---|---|
| 88% | 88% | 88% | 89% | 88.2% |

As the table shows, most transactions are now being completed through self-serve option.

**Q. What is your overall conclusion after reviewing the merger commitments in the first year?**

A. Enbridge Gas Utah is complying with the commitments it made at the time of the merger.

## VI. CONSERVATION ENABLING TARIFF REVIEW

**Q. Did the Commission order a reevaluation of the Conservation Enabling Tariff in the last general rate case?**

A. Yes. In Docket No. 22-057-03, the Commission stated, "The CET mechanism was implemented in 2006 and has been reauthorized in each general rate case since then. No party has asked us to discontinue the CET in this docket; accordingly, we approve its continued operation. Several parties have requested a more robust evaluation of the CET in DEU's next general rate case. We find that to be an appropriate way to ensure the CET continues to serve the objectives for which it was originally designed. We direct DEU to present a technical conference during the second or third quarter of 2023 to begin framing this evaluation." (Commission Order, Docket 22-057-03, December 23, 2002, page 51).

**Q. Did the Company hold a technical conference as ordered by the Commission?**

A. Yes. On July 6, 2023, the Company held a technical conference regarding the CET. A recording of the technical conference can be found on the Commission website under Docket No. 22-057-03. The presentation provided during that technical conference is attached as EGU Exhibit 1.03.

**Q. The Commission Order in Docket No. 22-057-03 highlighted the importance of ensuring the original objectives of the CET were still being satisfied. Were these objectives discussed in the CET technical conference?**

A. Yes. Originally, the CET was approved to remove the barrier for the Company to offer energy efficiency programs because revenue collected would not be impacted by declines in usage. That purpose is still served by the CET. In addition, as I discuss in more detail, the CET has provided the benefit of ensuring that revenue is neither under-collected nor over-collected by the Company.

**Q. Has the Company encouraged energy efficiency with its customers?**

A. Yes. Since the inception of the energy efficiency programs in 2007, the Company has paid out over 1.4 million rebates to about half of the customers in Utah. More specifically, since 2007, the Company has paid nearly 240,000 rebates to about 200,000 customers who replaced furnaces. Additionally, beginning in 2021, the Company first offered rebates to customers for purchasing and installing high efficiency dual fuel heating systems. Dual fuel heating systems are estimated by the Company to reduce annual natural gas usage related to space heating by nearly half of what the average customer would otherwise use annually. The Company is one of the earliest natural gas utilities in the United States to incentivize this type of technology. Since 2021, the Company has rebated over 9,500 dual fuel heating systems. Between the high efficiency furnaces and dual fuel heating systems purchased and installed, incentivized customers are forecasted to save over 50 million dekatherms of natural gas over the useful life of the equipment.

**Q. Can you provide an overview of the history of the CET?**

A. Yes. A timeline is provided on page 3 of EGU Exhibit 1.03. The evaluation of the CET began back in 2002. The Company filed a general rate case and in that case the Commission ordered the parties to create a task force to discuss alternative ratemaking options. Full revenue decoupling was one of those options, along with straight fixed variable option (revenue is collected through a very high basic service fee) and lost revenue option (lost revenue related to energy efficiency is estimated and collected through a rider). This led to a Company request in Docket No. 05-057-T01 to implement the CET as a 3-year pilot program. Ultimately, the parties in that case were able to agree to a settlement compromise where the Company would pilot full decoupling for three years and every year the Company would come back in and review the mechanism. The stipulation was approved in 2006 and in 2007, and the one-year review was completed, and the mechanism was allowed to continue. In 2008, the Company had a rate case during what would have been the year-two review period. Although there wasn't a lot of discussion about the CET in that case, the Commission permitted the CET to continue. The Commission extended the pilot program to 2010.

**Q. When was the CET changed from a pilot program to a regular ongoing program by the Commission?**

A. In 2010, a stipulation was reached in the Company's general rate case in Docket No. 09-057-16 whereby the parties agreed that the CET would no longer be a pilot program and would continue as an approved regular program by the Company. As such, 2025 marks 19 years that the CET mechanism has been in place. As I discuss in further detail below, the CET continues to serve the objectives for which it was originally designed and is just, reasonable, and in the public interest. As a result, the Company maintains that the CET should continue to operate.

**Q. Can you provide an overview of the mechanics of the CET?**

A. Yes. The CET is a revenue decoupling mechanism, which means that it adjusts revenue based on these usage differences over time. To determine the components for the mechanism, the first step is to set the allowed revenue per customer. This is done through a general rate case. Page 4 of EGU Exhibit 1.03 provides an example. In that example, the revenue requirement is $100. There are 10 customers and 100 Dths of projected usage. Through a general rate case, the allowed revenue per customer, once determined, and actual revenue are "coupled" so they are equal. After rates become effective, the number of customers and usage will change at different rates over time and revenue will become "decoupled". The CET adjusts revenue based on the usage as it changes over time. Page 6 of Exhibit 1.03 shows what would happen over time when declining usage occurs. In that instance, the hypothetical usage drops from 100 Dth to 90 Dth so only $90 would be collected through the volumetric rate. This is $10 less than the allowed revenue per customer, meaning that the under-collection is $10. As a result, in that example, the $10 under-collected amount would be recovered from customers over the following next year through a surcharge.

**Q. Does the mechanism return money to customers if the account becomes over-collected?**

A. Yes, the CET returns money to customers when the Company collects more revenue than allowed. That scenario is demonstrated through the example on page 7 of Exhibit 1.03. In that example, usage has gone up and the total amount of revenue collected is $110. Because the allowed revenue was only $100, the Company has over-recovered $10 from customers. This over collection would be returned to customers over the following year through a CET surcredit. As I explain below, the Company has been in an over-collected status for the last couple of years, meaning that funds have been returned to customers through the CET. Customers have not had to pay any surcharge amounts.

**Q. In addition to the information you provided in the July 6, 2023, technical conference, did parties who participated in the technical conference ask for any additional information to be discussed in your testimony in this case?**

A. Yes. A review of the technical conference identified eight areas where parties asked for additional information. A summary of these items is shown in the table below:

| Area | Location in technical conference | Request |
|---|---|---|
| Weather Normalization | 13 minutes | Explore additional methods other utilities use for calculating weather normalization |
| Usage impacts | 29 minutes | Provide a qualitative discussion on the different impacts on usage |
| Historical comparison of GS usage and rate | 30 minutes | Provide historical comparison of usage-per-customer and price for the entire GS class |
| Energy Efficiency savings | 35 minutes | Provide the annual and first year savings and lifetime gross savings provided by the program |
| Cost Effectiveness Tests | 44 minutes | Provide a deeper dive into tests discussed in DSM advisory group meetings |
| RIM Test | 46 minutes | Discuss trend in RIM and causes |

| | | |
|---|---|---|
| Decoupling mechanism map | 33 minutes | Update national map to show only gas utilities with decoupling mechanisms |
| Economic Literature | 42 minutes | Address the economic literature suggesting that revenue decoupling removes the incentive for a company to be operationally efficient. |

**Q. Do you address any of these issues further in your testimony?**

A. Yes. In the paragraphs that follow I'll provide additional detail about each area of interest.

### *A. Weather Normalization*

**Q. In the technical conference you were asked to explore additional methods for calculating weather normalization. Did you research that issue?**

A. Yes. Through a survey issued by the American Gas Association, we were able to ask peer utilities how they calculate weather normalization in their jurisdiction. Eleven peer companies responded to the survey. Mr. Landward and I also reached out to some industry experts to find out if they had seen any different methodologies.

**Q. Please summarize the findings.**

A. There are two main ways that gas utilities calculate weather normalization. The first method calculates a weather normalization adjustment ("WNA") for each individual customer each month and includes it as part of their bill. This is the methodology that the Company uses. The second method calculates WNA on an aggregate basis for all customers and then that revenue difference is collected through a surcharge or some other mechanism from all customers. Mr. Landward will discuss the AGA survey in more detail as well as a proposal to shorten the normal degree day baseline from 20 years to 10 years.

### *B. Usage Impacts*

**Q. In the technical conference you discussed different reasons customer usage can fluctuate over time. You were asked to provide that information in this proceeding. Please summarize the reasons for changes in usage.**

A. There are four main reasons that can cause differences between actual usage and forecasted usage in a rate case. They are weather, forecasting variances, price and energy efficiency.

**Q. Please discuss how weather impacts a customer's usage.**

A. Weather can increase customer usage, depending on whether it is colder than normal or warmer than normal. Intuitively, if it is colder than normal, customer usage increases, while the opposite is true if it is warmer than normal. As Mr. Landward will discuss, the Company believes that the application of a WNA to the non-gas portion of the bill creates more accurate billing than no WNA at all.

**Q. Please discuss how forecasting variance can cause usage to be higher or lower than expected.**

A. In rate cases, test period billing determinants are forecasted. Specifically in this case, the forecasted Dths are based upon the Company's estimate of 2026 volumes. It should be noted that whether billing determinants are based on a historical or forecasted number, it is still a forecast because actual usage will be different from whatever is used for rate setting purposes. Due to the large number of volumes involved in the forecast, even a small difference can create a material change in revenue.

**Q. How does the CET help eliminate the effects of forecasting error?**

A. The CET ensures that the Company only collects its allowed revenue per customer. Customer estimation is much more accurate than usage estimation. For example, in the last 10 years, the Company has added between 22,000 and 28,000 customers annually. Assume the Company estimates 22,000 customers but really adds 28,000 customers. A 6,000 customer difference would be a big difference in a customer forecast. However, because the existing customer base is 1.1 million customers, the forecast would only be off by one half of one percent. Because usage is dependent on so many variables and lifestyle changes, a usage forecast within one half of one percent of the actual customer number would still be viewed as an accurate forecast. Because the CET forecast focuses on the customer forecast and adjusts away any differences due to usage, the revenue collection is more accurate, protecting both the Company and the customer.

**Q. Please discuss the impact that energy efficiency has on usage?**

A. As more efficient appliances and building measures are used in homes, this energy efficiency should reduce the amount of energy used in the home. I will discuss this in more detail in section D below.

**Q. Please provide a comparison of how price impacts customer usage.**

A. Like weather, price is inversely related to usage. While natural gas usage is thought to have a certain amount of inelasticity, customer behavior will change if the price change is too dramatic. In the technical conference a slide was shared that showed residential usage per customer compared with the real GS rate from 2006-2021. This slide is provided on page 11 of EGU Exhibit 1.03. While the full effect of price on usage is difficult to isolate with full certainty, the trend in price has most likely had the effect of increasing customer usage over time holding everything else constant. In the technical conference a request was made to show the total average general service customer usage relative to price. This would be different from the original chart that provided just residential usage and not all general service customers.

### *C. Historical comparison of GS usage and rate*

**Q. Have you updated the graph in Exhibit 1.03 page 11 to include the usage of all General Sales customers?**

A. Yes, that chart has been provided as EGU Exhibit 1.04. As the chart shows, except for a price bump due to commodity shocks in 2022-2023, the GS winter rate has steadily decreased over the last 19 years.

### *D. Energy Efficiency savings*

**Q. Please discuss how energy efficiency has reduced usage over time on your system?**

A. As was previously stated, since 2007, the Company has incented customers to reduce their usage. Additionally, the Company has offered home energy audits since the beginning of the programs and introduced customer energy comparison reports starting in 2011. These two initiatives have also helped to change customer energy usage behaviors. Although it's difficult to quantify how much energy efficiency specifically has impacted customer usage over time, it is generally agreed that the result has been a decrease. A summary of Dth savings since the inception of the program is provided in the table below:

| Years | Total Annual (Gross) Dth Savings | Total Lifetime (Gross) Dth Savings | Number of Rebates Paid |
|---|---|---|---|
| 2007-2016 | 7,137,046 | 158,524,991 | 900,222 |
| 2017 | 1,044,307 | 15,376,023 | 73,883 |
| 2018 | 998,419 | 12,734,226 | 76,690 |
| 2019 | 1,099,047 | 15,095,194 | 77,081 |
| 2020 | 1,158,448 | 19,038,255 | 86,169 |
| 2021 | 931,950 | 15,439,817 | 57,768 |
| 2022 | 949,449 | 16,018,029 | 53,429 |
| 2023 | 1,047,764 | 16,239,031 | 54,968 |
| 2024 | 927,035 | 15,423,781 | 59,500 |
| Total | 15,293,465 | 283,889,347 | 1,439,710 |

**Q. Please explain the difference between Total Annual (Gross) Dth Savings and Total Lifetime (Gross) Dth Savings.**

A. The Annual Gross Dth Savings figure represents the aggregate annual deemed savings for every measure that resulted in a rebate being paid out to a customer. So, for example, a customer who installed a 95% high efficiency furnace has an annual (Gross) deemed savings of 11.8 Dths for the next 20 years. The chart shows that, in 2024, all the rebates paid sum to a total of 927,035 Dths saved. The Total Lifetime Gross Dth Savings figure represents the deemed savings over the life of the measure. Going back to the furnace example, the deemed savings for a furnace would be 236 Dths (11.8 Dths X 20 years). The Total Lifetime Gross Dth savings would be the sum of all these lifetime savings calculations for each measure paid.

**Q. In the case of annual savings, wouldn't they be cumulative over time?**

A. Yes. For example, if the program paid one furnace rebate every year, those savings would stack over time so that the savings would be cumulative. A five-year example is shown in the table below:

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| | 11.8 | 11.8 | 11.8 | 11.8 | 11.8 |
| | | 11.8 | 11.8 | 11.8 | 11.8 |
| | | | 11.8 | 11.8 | 11.8 |
| | | | | 11.8 | 11.8 |
| | | | | | 11.8 |
| Total | 11.8 | 23.6 | 35.4 | 47.2 | 59 |

Because the natural gas savings compound over time, the amount of annual savings in 2024 is closer to the 15.3 million Dths per year than the 927,000 Dths per year shown in the table on the prior page. This is how the Company's cost effectiveness model (Model), based on the California Standard Practice Manual and first used by the Company in Docket No. 05-057-T01, has evaluated natural gas savings since the beginning of the programs.

**Q. How do these savings figures compare to the Company's total usage each year?**

A. Total sales for the Company in 2024 were 213,396,183 Dths. For General Service customers in Utah, the amount was 106,719,832 Dths.

**Q. What is the general takeaway from this energy efficiency data?**

A. Whether you look at the cumulative number or the annual number, the Company has encouraged energy efficiency for its customers, and customers have become more efficient. As was mentioned earlier, this was the main goal of the CET in the original docket.

### *E. Cost Effectiveness Tests*

**Q. In the technical conference there was a lot of discussion about cost effectiveness tests. Were there any requests made with respect to these measures of energy efficiency?**

A. Yes. A request was made that a deeper dive on cost effectiveness tests be provided in an upcoming energy efficiency advisory group meeting.

**Q. Has this been discussed in an advisory group meeting?**

A. Yes. The Company held a meeting on April 29, 2025, and the four resource cost tests were explored in greater detail.

### *F. Ratepayer Impact Measure Test*

**Q. Were there questions about the Resource Impact Measure ("RIM") Test in the technical conference?**

A. Yes. Specifically, there was interest in the trend of the RIM test over time. The historical trend for all four tests is shown in the table below:

| **Year** | **TRC** | **UCT** | **PCT** | **RIM** |
|---|---|---|---|---|
| **2018** | **1.00** | **2.88** | **1.24** | **0.73** |
| **2019** | **1.10** | **2.75** | **1.49** | **0.84** |
| **2020** | **1.38** | **3.33** | **1.86** | **0.85** |
| **2021** | **1.54** | **3.79** | **1.82** | **0.87** |
| **2022** | **1.86** | **2.05** | **4.38** | **0.96** |

| | | | | |
|---|---|---|---|---|
| **2023** | **1.58** | **1.90** | **5.27** | **0.90** |
| **2024** | **1.62** | **1.78** | **5.30** | **0.88** |

As the table shows, the RIM had been increasing from 2018 through 2022. In the technical conference the question was asked what was causing the trend.

**Q. What caused the increase in the trend in RIM from 2018 to 2022?**

A. To explain the cause of the trend it's important to understand how the RIM is calculated by the Model. The Model evaluates benefits/costs and returns a net present value calculated from the useful life of the incented equipment. For the RIM the benefits are the avoided costs to all customers due to the various energy efficiency measures being implemented. These benefits are divided by the lost revenue because of the decrease in gas usage plus the program costs paid by all customers, whether they participate in the programs or not. The RIM is calculated for each program and then aggregated. The large increase from 2018 and to 2022 was driven mainly by avoided costs. For example, the average modeled first year avoided cost in 2017 was $2.93 and rose to $6.16 in 2022 as the Company saw higher gas costs. As gas costs have come down over the last couple of years it has in turn caused the RIM ratio to also decrease.

### *G. Decoupling mechanism map*

**Q. In the technical conference you provided a map showing which states had approved decoupling. Was there additional discussion about this map in the meeting?**

A. Yes. The map provided in the technical conference included both electric and gas utilities. This map is shown on pages 13 and 14 of EGU Exhibit 1.03. A request was made to provide the map for gas utilities only. This map is provided as EGU Exhibit 1.05. As the map shows, most states have some sort of rate stabilization mechanism for gas utilities. As I mentioned in the technical conference, Utah was one of the leaders in implementing revenue decoupling.

### *H. Economic Literature*

**Q. In the technical conference you were asked to address economic literature that suggests that the CET removes the incentive for a utility to be operationally efficient. Can you summarize this concern in more detail?**

A. Yes, this is like an argument in the original docket where parties argued that the CET would guarantee a Company's allowed return. That argument suggests that, because the Company receives an allowed amount of revenue per customer, it will no longer need to watch the bottom line because recovery is guaranteed. With a simple example I can show that this argument is flawed.

**Q. Please explain the example.**

A. In this example, I will compare three local distribution companies. All three companies have the same revenue, expenses and net income. They all file rate cases at the same time and receive the same revenue requirement. The only difference between the three companies is that Company A has revenue decoupling, while Companies B and C do not.

The rate outcome for each Company is shown below:

| Company A | Company B | Company C |
|---|---|---|
| Revenue: $1,000 | Revenue: $1,000 | Revenue: $1,000 |
| Expense: $800 | Expense: $800 | Expense: $800 |
| Net Income: $200 | Net Income: $200 | Net Income: $200 |
| Customers 100 | Customers 100 | Customers 100 |
| Volumes: 1,000 | Volumes: 1,000 | Volumes: 1,000 |

Assume that Company B sees lower usage per customer in the following year and Company C sees higher usage per customer during the same period. The result after year one is shown in the graphic below.

| Company A | Company B | Company C |
|---|---|---|
| Revenue: $1,000 | Revenue: $900 | Revenue: $1,100 |
| Expense: $800 | Expense: $800 | Expense: $800 |
| Net Income: $200 | Net Income: $100 | Net Income: $300 |
| Customers 100 | Customers 100 | Customers 100 |
| Volumes: 1,000 | Volumes: 900 | Volumes: 1,100 |

In between rate cases, the main way for a utility to become more profitable is by reducing expenses. It can also increase revenue, but typically that comes with associated capital investment and cost. In the case of each company, reducing expenses will make them more profitable. For purposes of this example, assume that each company was able to reduce expenses by $50 in year 1. The overall result would look like this:

| Company A | Company B | Company C |
|---|---|---|
| Revenue: $1,000 | Revenue: $900 | Revenue: $1,100 |
| Expense: $750 | Expense: $750 | Expense: $750 |
| Net Income: $250 | Net Income: $150 | Net Income: $350 |
| Customers 100 | Customers 100 | Customers 100 |
| Volumes: 1,000 | Volumes: 900 | Volumes: 1,100 |

In all three cases, the company would have the incentive to cut costs and be more profitable.

**Q. You have used a theoretical example to answer a theoretical question. Do you have any real-world evidence to support your answer?**

A. Yes. Even with revenue decoupling, over the 19 years that the CET has been in effect, the Company struggled to achieve its allowed return because of the regulatory lag caused by constantly investing in capital. The table below shows the Company's allowed vs. actual regulated return since the inception of the CET.

| **Year** | **Allowed Return** | **Actual Regulatory Return** |
|---|---|---|
| **2006** | **11.2%** | **10.86%** |
| **2007** | **11.2%** | **10.28%** |
| **2008 **** | **10.7%** | **10%** |
| **2009** | **10.0%** | **9.73%** |
| **2010**** | **10.35%** | **9.27%** |
| **2011** | **10.35%** | **9.84%** |
| **2012** | **10.35%** | **8.62%** |
| **2013** | **10.35%** | **8.44%** |
| **2014**** | **9.93%** | **9.59%** |
| **2015** | **9.85%** | **9.59%** |
| **2016** | **9.85%** | **9.51%** |
| **2017** | **9.85%** | **8.26%** |
| **2018** | **9.85%** | **9.79%** |
| **2019** | **9.85%** | **8.18%** |
| **2020**** | **9.56%** | **9.52%** |
| **2021** | **9.5%** | **8.9%** |
| **2022** | **9.5%** | **9.07%** |
| **2023** | **9.6%** | **9.11%** |
| **2024** | **9.6%** | **8.24%** |

**In these years, the Company received a Commission order changing the allowed ROE mid-year. For these data points a pro-rata ROE has been calculated.

As the data shows, during the time that the Company has had revenue decoupling, it has not earned a guaranteed allowed return.

**Q. In the original case, some parties argued that the CET would guarantee the Company would receive its allowed return. As demonstrated above, this has not occurred. Can you explain why it didn't occur?**

A. Because a large portion of the invested capital does not receive cost recovery until its included in a rate case, the Company constantly experiences regulatory lag as the associated financing costs, depreciation and taxes on that capital are incurred without rate relief between rate cases. For this reason, Company management always has a reason to try to be more efficient. Not only does the data not support the guaranteed-return argument, but it suggests that the CET has protected customers by not allowing the Company to over-earn.

**Q. Please explain how the mechanism has protected customers?**

A. Every three years when rates are set in a rate case, forecasted billing determinants are used to calculate a rate. Stated simply, the total estimated revenue is divided by estimated Dths to calculate a $/Dth charge for customers. Because the Company collects its General Sales revenue on a per-customer basis, the CET mechanism will reduce the revenue collected if the actual billed revenue ends up being higher than the forecast and the Company over collects revenue.

**Q. Has this happened while the CET has been in existence?**

A. Yes. It has happened often during the 19 years the CET has been in effect. A summary of CET adjustments by year is provided in EGU Exhibit 1.06. As the exhibit shows, the Company has over collected a net amount of $44.9 million during the program. As Mr. Landward discusses, the WNA may be the cause of some of this revenue over-collection. Absent the CET this excess revenue would have likely caused the Company to over earn in certain periods.

**Q. The evidence shows that the CET has protected customers but there have been years when the CET has benefitted the Company by collecting additional revenue, correct?**

A. It is correct that the CET can and has protected both customers and the Company from over- or under-collections but that protection is asymmetric.

**Q. How is it asymmetrical?**

A. Under the current CET mechanics, accruals for an under-recovery, which benefits the Company, are capped. This 12-month rolling accrual cap is based on 5% of total revenue. For example, as of the end of February 2025, the total cap is about $21.5 million. (Allowed revenue of $430.4 million for 12 months ended February 2025 multiplied by .05). For over-recovered revenue, which benefits customers, there is no cap. In the last year for example, the balance in the CET has been above $21.5 million, but no cap has been applied. For this reason, the Company is protected up to 5% while customers have unlimited protection. This is why the mechanism is asymmetrical.

**Q. Please summarize the Company's position regarding the CET?**

A. As the Commission stated in its order in Docket No. 22-057-03, the purpose of the CET evaluation in this case is to ensure the CET continues to serve the objectives for which it was originally designed. The evidence shows that the CET has effectively removed the disincentive for the Company to offer energy efficiency programs and continues to serve that purpose. The CET has also provided the added benefit of ensuring that the Company's overall revenue collection and the amounts paid by customers are not adversely impacted by changes in usage. This has been beneficial to the Company in some years and to customers for most of the time, and these protections are asymmetric relative to the benefit being greater for customers. While this benefit was not a focus of the original CET approval docket, history has shown that the mechanism has protected customers from being overcharged over time. For these reasons, the Company proposes that the CET continue going forward.

## VII. INFRASTRUCTURE RATE ADJUSTMENT MECHANISM

**Q. Is the Company proposing any changes to the Infrastructure Rate Adjustment Mechanism ("Infrastructure Tracker Program" or "ITP")?**

A. The Company is not proposing any substantive changes to the program. The Company is only requesting that the program continue as it has previously been approved by the Commission.

**Q. Does the Company believe that the continuation of this program is in the public interest?**

A. Yes. In its Report and Order issued on February 25, 2020 in Docket No. 19-057-02 ("Commission Order"), the Commission stated: "We find and conclude that continuing the ITP is in the public interest because it facilitates the needed replacement of aging infrastructure in a manner that encourages a relatively constant amount of investment in between rate cases and allows for a transparent process regarding the work accomplished and the work remaining to be done." (2019 Commission Order, at 10). Further the Commission determined: "We conclude a spending cap indexed for inflation (by the same GDP deflator index included in the most recent stipulation) balances customer and shareholder interests. Accordingly, we find that a spending cap of $72.2 million is just and reasonable in result and we approve a spending cap at that level. We conclude that indexing that spending cap for inflation (by the same GDP deflator index we approved in the most recent GRC) balances ratepayer interests with the objectives of the ITP. The GDP deflator will continue to be used as an annual index to adjust the cap on an ongoing basis." (Commission Order at page 13).

The Commission reiterated this statement in its Report and order issued on December 23, 2022 in Docket No. 22-057-03, when it said "[W]e conclude that the Tracker continues to be in the public interest. We also conclude that a spending cap continues to balance customer and shareholder interests. Accordingly, we find and conclude that a spending cap of $84.7 million is just and reasonable in result and we approve a spending cap at that level. We conclude that indexing that spending cap for inflation (by the same GDP Deflator index we approved in the 2020 GRC) balances cost control interests with the objectives of the Tracker. The GDP Deflator will continue to be used as an annual index to adjust the cap on an annual basis" (2022 Commission Order at page 15). The Company agrees with the statements the Commission made in the last two general rate cases and believes that they are still relevant today. The Company requests that the Commission approve the continuation of the ITP at the current budget level, adjusted in future years using the GDP deflator.

**Q. Is the Company proposing to include the cumulative total infrastructure replacement costs that have been previously included in the current surcharge, into base rates?**

A. Yes.

**Q. How does it propose to do so?**

A. All of the plant, accumulated depreciation, accumulated deferred taxes, depreciation expense and taxes other than income taxes that were separately identified in the ITP proceedings and that have been separately tracked since the last general rate case have been included in their respective FERC accounts and included in the average 2026 test period. As such, these costs are part of the total revenue requirement proposed by Mr. Stephenson, and they have also been included in the Distribution Non-Gas ("DNG") portion of each rate schedule proposed by Mr. Summers.

**Q. What will happen to the surcharge at the time new base rates are approved?**

A. The surcharge will be reset to zero. EGU Exhibit 7.02 includes Tariff Rate Schedules in 2.02, 2.03, 2.04, 4.02, 5.02, 5.04, 5.05 and 5.06, which illustrate this reset. As can be seen, the Infrastructure Rate Adjustment line shows zero for all block usage. In effect, all ITP costs and associated surcharge will be "rolled up" into the base DNG rate upon the effective date of the Commission order in this docket.

**Q. Assuming new rates are set based on an average 2026 test period, at what point in time will replacement investment for feeder lines and IHP beltlines begin to be included in the Infrastructure Tracker.**

A. The Company has included $96 million of ITP capital spend in rate base in the proposed average 2026 test period. This $96 million includes a total of $58.7 million (EGU Exhibit 1.07, column B, Line 9) added to rate base in 2025 and an additional $88.8 million added to rate base in 2026. The $88.8 million is averaged so that $37.3 million is included in average rate base in 2026. In total $96 million of 2025 and 2026 investment is included in base rates, as shown on Line 22. As such, any investment above $96 million that is put into service on or after January 1, 2025, should be included in the future ITP surcharge calculations. Any incremental investment below $96 million has been included in the base DNG rate calculation and should not be included in the ITP. Additionally, the effective date of any incremental surcharge related to the Infrastructure Tracker should be set on or after January 1, 2026, when new rates take effect in this case. Both limiting criteria will ensure that no ITP costs will have been included twice and that rates are just and reasonable. The Company's first request, following this general rate case to adjust rates for the cost of ITP infrastructure will include evidence showing that these two limiting criteria have been satisfied. Attached as EGU Exhibit 1.07 is a summary of the ITP costs that the Company has included in its 2025 and 2026 projected capital additions and is the basis for the amount included in the 2026 average test period. (See column B, line 22). This calculation uses the same reasoning that was used in the rate cases in Docket Nos. 13-057-05, 19-057-02 and 22-057-03.

**Q. Why should the Company begin tracking infrastructure replacement beginning January 1, 2025 and not January 1, 2026, the beginning of the test period?**

A. Because the Company has estimated the amount of ITP spending that it will make in 2025, starting the "clock" on January 1, 2025 and using a threshold that includes both 2025 and 2026 estimated ITP spend will ensure equitable rate recovery for both customers and the Company.

**Q. Please summarize the Company's request related to the ITP.**

A. The Company requests that the ITP be allowed to continue at currently approved 2024 spending amounts of $86,730,000, adjusted annually using the GDP inflator. Additionally, the Company requests that the threshold of $96 million be set and that all actual ITP spending from January 1, 2025 be tracked until the cumulative spending amount has exceeded that threshold, at which point any excess investment be included in the ITP surcharge.

## VIII. RURAL EXPANSION TRACKER

**Q. Has the Company included any capital investment for rural expansions in the test period?**

A. Yes. On February 21, 2025, in Docket No. 24-057-13, the Commission approved a settlement stipulation for expansion into Portage, Utah. The costs of that project as well as anticipated costs of future rural expansion projects in 2026 have been included in the test period.

**Q. How much has been included in the test period for these projects?**

A. EGU Exhibit 1.07 summarizes the amounts included in the test period. As the exhibit shows, there is $8.49 million of spend included in 2025 (Column C, line 9) and $20.9 million of spend included in 2026. The $20.9 million is averaged so that $8.7 million of actual investment for 2026 will be included in base rates. The total amount of rural expansion capital spend included in base rates is $17.2 million.

**Q. The Company has typically collected costs for these rural expansion projects through a rider. How does the Company propose rate recovery for these projects in the future?**

A. It is anticipated that the rural expansion cost recovery would be treated like the ITP. Assuming the Commission includes $17.2 million in base rates, that would be the threshold that would need to be spent before the Company would ask to recover rural expansion costs through a rider between rate cases. The tracking of those costs would begin January 1, 2025, and would continue until the threshold would be met.

**Q. Can you summarize your proposal related to rural expansion costs?**

A. Yes. The Company proposes that the $17.2 million of related costs for rural expansions be included in base rates. We also propose that $17.2 million be used as a threshold and that rural expansion costs be tracked beginning January 1, 2025, and that any costs exceeding the threshold be allowed to be recovered through a rider.

## IX. CONCLUSION

**Q. Would you please summarize your recommendations?**

A. Yes. The rates proposed by Enbridge Gas Utah in this case are just and reasonable. They reflect the prudent costs the Company will incur in providing safe, reliable and adequate service to its customers during the rate-effective period. The cost of service and rate design proposed by EGU represents a fair apportionment of costs among our customer rate classes and provides customers with the correct signals to use natural gas efficiently. I recommend that the Commission approve the proposed revenue requirement, rates and Tariff changes described in the Company's Application and testimony.

Additionally, the Company recommends that the CET mechanism as currently implemented be approved going forward. The mechanism has allowed the Company to encourage energy conservation and has also provided the added benefit of protecting customers for revenue over collection. For these reasons the CET should be approved on a going forward basis.

Finally, the Company requests that the Infrastructure Tracker Rider continue as described in Section 2.07 of the Company's tariff and that the rider mechanism begin to collect costs after $96 million of eligible spending has occurred after January 1, 2025 and the expansion rider begin to recover costs after $17.2 million of eligible spending has occurred after January 1, 2025.

**Q. Does this conclude your testimony?**

A. Yes.

State of Utah )

) ss.

County of Salt Lake )

I, Kelly B Mendenhall, being first duly sworn on oath, state that the answers in the foregoing written testimony are true and correct to the best of my knowledge, information and belief. Except as stated in the testimony, the exhibits attached to the testimony were prepared by me or under my direction and supervision, and they are true and correct to the best of my knowledge, information and belief. Any exhibits not prepared by me or under my direction and supervision are true and correct copies of the documents they purport to be.

Kelly B Mendenhall

SUBSCRIBED AND SWORN TO this 1st day of May, 2025.

Notary Public

RENA PORTER
Notary Public State of Utah
My Commission Expires on:
April 25, 2027
Comm. Number: 730504