BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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

JORDAN K. STEPHENSON

FOR

ENBRIDGE GAS UTAH

May 1, 2025

EGU Exhibit 4.0

TABLE OF CONTENTS

I. INTRODUCTION **1**
II. BASE AND TEST PERIODS **3**
III. TEST PERIOD REVENUES **6**
A. Distribution Non-Gas ("DNG") Revenues **6**
B. General Related Other Revenue **9**
C. Excess Deferred Income Tax Adjustment **9**
IV. TEST PERIOD EXPENSES **11**
A. Operating and Maintenance Expenses **11**
B. Depreciation Expense **23**
C. Other Operating Expenses **24**
V. TEST PERIOD RATE BASE **25**
A. Net Plant-in-Service **25**
B. Other Rate Base Accounts **27**
VI. COST OF CAPTIAL **30**
VII. PROJECTED DEFICIENCY AND REVENUE REQUIREMENT **31**

I. INTRODUCTION

Q. Please state your name and business address.

A. Jordan K. Stephenson, 333 South State Street, Salt Lake City, Utah 84111.

Q. By whom are you employed and in what capacity?

A. I am employed as a Manager of Regulation for Enbridge Gas Utah (EGU). My qualifications are detailed in EGU Exhibit 4.01. I am filing testimony on behalf of Questar Gas Company dba EGU ("Enbridge Gas," "EGU" or the "Company").

Q. Were the attached EGU Exhibits 4.01 – 4.33 prepared by you or under your direction?

A. The inflation factors shown in EGU Exhibit 4.07 were prepared by S&P Global. All other exhibits were prepared under my direction.

Q. What general areas does your testimony address?

A. My testimony explains how I calculated EGU's revenue requirement for this case and why the Company requests to increase its distribution non-gas ("DNG") rates to collect an additional $114.7 million beginning on January 1, 2026. I explain why the proposed test period of the average 13 months ending December 2026 best reflects the conditions that will exist during the rate-effective period. I also address each component of the Company's revenue requirement and the methods used to measure the financial conditions that will exist during the average 2026 test period.

Q. What is contributing to the Company's revenue requirement increase in 2026?

A. The increase is primarily driven by capital investment and related expenses, updated depreciation rates, and a general increase in operating and maintenance expenses since the Company's last general rate case.

The Company maintains a significant annual capital investment program to support customer growth and necessary upkeep and maintenance of existing infrastructure. The average gross plant balance in 2026 is projected to exceed the 2023 test period balance by $1 billion. This investment directly increases depreciation expense, property taxes, and the cost of capital that is made up of debt and equity costs. Holding all else equal, this increased gross plant balance would increase costs by approximately $121.4 million since the last general rate case.[1]

The Company is also filing an updated depreciation study based on year-end 2022 plant balances. The prior depreciation study was conducted using plant data through 2017. The updated study, conducted by the consulting firm Gannett Flemming, proposes an increase in depreciation rates resulting in approximately $25 million in additional depreciation expense annually. This would also increase the projected accumulated depreciation balance, resulting in a net impact of $22.6 million to the Utah revenue requirement in 2026.

Q. Has your analysis of the 2026 test period conditions also included factors that would reduce the Company's revenue requirement?

A. Yes. Accumulated depreciation and deferred income tax balances are projected to grow through 2026. These balances reduce overall rate base, decreasing the Company's revenue requirement. In addition, allocated costs from the Company's new parent, Enbridge Inc., are projected to be lower than equivalent costs from Dominion Energy prior to the sale of Questar Gas Company to Enbridge Inc.

I have also included revenue growth in my analysis. Due to customer growth the Company will collect more revenue through 2026 as new customers tie into the distribution system. The resulting incremental revenues help to offset the required rate increase in this case.

I walk through each of these items in more detail throughout the remainder of my testimony. To conclude this high-level summary, after accounting for all the various

1 This is calculated using the pre-tax return on rate base (8.44%), average depreciation rates (2.5%), and property tax rates (1.2%) from the last general rate case, Docket No. 22-057-03.

elements that make up the average 2026 test period, the Company will be operating at a revenue deficiency of approximately $114.7 million. EGU respectfully requests that rates be adjusted to collect this additional amount in this case.

II. BASE AND TEST PERIODS

Q. What base period is the Company proposing to use in this case?

A. The Company proposes to use as the base period the 13-month period ending December 31, 2024. This constitutes the Company's most recent full calendar year of actual revenues, expenses, and rate base balances that will serve as the foundational starting point for the revenue requirement calculation.

Q. What test period is the Company proposing to use in this case?

A. The Company proposes to use as the test period the average 13-month period ending December 31, 2026, supported by a mix of historical activity and 2026 forecasted data. As I discuss later, this test period coincides with and best reflects the conditions that will exist during the rate-effective period beginning in January 2026.

Q. Is the proposed test period consistent with the Utah Public Service Commission's ("Commission") test period requirements found in Section 54-4-4 (3) (a) of the Utah Public Utility Code?

A. Yes. Section 54-4-4(3)(a) provides that, "the Commission shall select a test period that, on the basis of evidence, the Commission finds best reflects conditions that a public utility will encounter during the period when the rates determined by the Commission will be in effect." The Commission may use a future test period based on projected data not exceeding 20 months from the date a proposed rate change is filed. The Company's proposed test period fully complies with this requirement in that it is based on 20 months of projected data from the May 1, 2025 filing date.

Q. How does the 2026 test period compare with the rate-effective period?

A. The test period and the rate-effective period would each take effect on January 1, 2026. While the test period would end on December 31, 2026, the rate-effective period would continue into future years. It is unknown when the rate-effective period will end, but if history is any indication, the rate-effective period could extend through 2028.

During 2026, the two periods will overlap, resulting in a synchronization of utility costs and revenues required to cover those costs. Beyond 2026, the Company would operate at a gradually increasing deficiency for incremental capital investment or expenses not included in revenues from approved rates.[2]

As such, the Company's proposed future test period, using average-year data, is the best possible reflection of the conditions EGU will encounter during the rate-effective period. By contrast, relying solely on annual amounts prior to 2026 would not reflect conditions expected to occur during the rate-effective period, let alone thereafter.

Q. Do you think the synchronization of investment, revenues and expenses is an important factor to consider?

A. Yes. Synchronization is an essential part of creating an accurate forecast. There is a direct link between the number of customers served by the system, the revenues generated by the system, and the investment needed to provide service to the Company's customers. As the number of customers rises, the investments needed for the system and the corresponding revenue from those customers also increase. Depreciation expense, property taxes and deferred income taxes are also linked to investment. The Company has considered all of these items together to develop a test period that best reflects the conditions that will occur during the rate-effective period.

2 "Rates" here refers to base DNG rates approved in this case as well as any incremental rate increases from other programs collected in separate rate proceedings, such as the Company's infrastructure tracker programs.

Q. How have you synchronized the rate base, expenses and revenues?

A. Beginning with December 2024 rate base balances, I projected net plant and other rate base accounts for 2025 and 2026. Rate base changes are largely driven by capital expenditures required to serve new customers in 2025 and 2026 and to maintain the distribution system to continue to safely serve existing customers. This investment in turn enables incremental revenue from new customers and ongoing revenues from existing customers, which have been incorporated into the revenue forecasts for 2025 and 2026. In addition to revenues, this investment also results in incremental and ongoing depreciation expense, property taxes and deferred income taxes. I have incorporated these items into the expense forecasts in 2025 and 2026.

Q. How did you develop the 2026 test period and revenue requirement?

A. In simplified terms, the Company's revenue requirement is calculated by summing up each of the following:

O&M Expenses (Labor, Overhead and Non Labor Expenses)

Other Operating Expenses (Depreciation, Other Taxes, Income Taxes)

Return on Rate Base (Weighted Average Cost of Capital)

The deficiency, or amount by which revenues should be increased for the test period, is equal to the total revenue requirement less the amount of revenues the utility will collect absent a rate adjustment in this case, adjusted for the income tax and bad debt related to increased revenues.

I have attached a one-page summary of the 2026 test period as EGU Exhibit 4.02. The exhibit is vertically organized into two sections. The top section includes income statement items of revenues and expenses, ending with a net operating income on row 28. The lower section is comprised of rate base balances, with the total rate base shown on row 52.

EGU Exhibit 4.02 is also horizontally organized into several columns. Column B provides unadjusted 2024 base period amounts from the Company's historical financial records. These amounts serve as the foundation for the 2026 test period. Column C shows total adjustments to 2024 revenues, expenses, and rate base to arrive at the anticipated 2026 level. Column D presents the imputed income tax adjustment. Columns B, C and D are added together to calculate the adjusted system total in column E. Finally, I apportioned the amounts to the Utah or Wyoming jurisdiction by direct assignment or by allocation using one of three allocation factors: gross plant, rate base, or gas sales (throughput). The Utah jurisdictional amounts are shown in column F.

Throughout the remainder of my testimony, I explain each component of the revenue requirement shown in EGU Exhibit 4.02 and how the amounts were derived.

III. TEST PERIOD REVENUES

A. Distribution Non-Gas ("DNG") Revenues

Q. How have you projected revenues for the 2026 test period?

A. My revenue projection begins with actual booked 2024 revenues. I then removed special program revenues (like Energy Efficiency or Sustainable Transportation Energy Plan ("STEP")) as these are handled through balancing accounts and surcharges in separate rate proceedings. I then adjusted those revenues up for anticipated increases in 2025 and 2026 absent rate relief in this proceeding.

EGU Exhibit 4.02, column B, Row 3 provides historical system DNG revenues booked in the 2024 base period, or $537.8 million. The increase in revenues through 2026, net of excluded Energy Efficiency and STEP revenues, is shown in column C, row 3 of EGU Exhibit 4.02. This is added to historical revenues to arrive at the adjusted system total revenue amount of $555.7 million (column E), of which $542.0 million is Utah related (column F). A detailed breakdown of revenues by class is provided in EGU Exhibit 4.03.

Q. What factors contribute to the projected increase in revenues through 2026?

A. The increase is a reflection of customer growth through 2026 as well as projected revenue increases from the Company's Infrastructure Replacement and Rural Expansion tracker programs.

Because the Company books the allowed-revenue-per-customer for its GS class under the Conservation Enabling Tariff (CET) mechanism, estimated revenues are largely a function of projected customers multiplied by the allowed revenue per customer approved in the Company's last general rate case, Docket No. 22-057-03. The Company has seen a steady increase in customers over time. The historical and projected customer growth rate is provided below:

Year	Average Customers	Customer Growth
2020	1,070,317	
2021	1,098,034	2.59%
2022	1,126,548	2.60%
2023	1,152,560	2.31%
2024	1,174,736	1.92%
Est. 2025	*1,195,896*	*1.80%*
Est. 2026	*1,217,622*	*1.82%*

Q. What is the basis of the projected 2025 and 2026 customer counts?

A. The projected 2025 and 2026 customer totals are based on the Company's updated Integrated Resource Plan forecast that will be filed in June 2025. The updated forecast incorporates contemporaneous and projected economics at the beginning of 2025. In 2024, average customer count increased by 1.92%. The IRP projections show continued growth of 1.80% in 2025 and 1.82% in 2026. The slightly reduced growth rates in 2025 and 2026 reflect some slowing and projected slowing in the housing market due to affordability constraints and a slower rate of apartment unit construction in the short term.

Q. Has the Company also forecasted customer usage for the 2026 test period?

A. Yes. Projected customer usage is important in that it provides the billing determinants on which rates will be set in this case. EGU Exhibit 4.04 shows the historical and forecasted use per customer for the GS class in Utah, based on normal heating degree days (NHDD) using a 20-year period ending December 2018, as approved in Docket No. 19-057-02.

In this case the Company proposes to update the NHDD to a 10-year period ending December 2024. This is discussed more thoroughly in the direct testimony of Mr. David C. Landward. The table below shows the projected usage-per-customer for 2025 and 2026 using the proposed NHDD.

	Usage Per Customer (Dth)	**Change From Prior Year (Dth)**
Historical 12 Months Ended December 2024	96.61	
Projected 12 Months Ended December 2025	96.25	(0.36)
Projected 12 Months Ended December 2026	96.67	0.42

The projected usage-per-customer is 96.25 Dth in 2025 and 96.67 in 2026. These figures were derived from forecasted demand and customer levels within the GS class. Mr. Summers has based his cost allocation and rate design in this docket upon the same forecast. Holding revenue requirement constant, higher projected usage results in lower rates, while lower projected usage results in higher rates. Projecting total volumetric usage can be challenging, and the Company often sees volatility in customer usage outside of expectations. Recognizing this volumetric volatility exists, the CET mechanism addresses the Company's earnings from customer usage and pegs the amount of revenue the Company can recognize to the allowed-revenue-per-customer. Variations between volumetric revenue and allowed revenue under the CET are booked to the CET balancing account and amortized through the CET surcredit or surcharge.

B. General Related Other Revenue

Q. Line 7 of EGU Exhibit 4.02 also is a line item for "General Related Other Revenue" ("Other Revenue"). How does this line item impact the revenue requirement in this case?

A. Other Revenue is made up of revenues the Company receives for activities not directly related to distributing natural gas. For example, these include interest on past due accounts, equipment lease revenues, and capacity release revenues. These revenues reduce the revenue requirement the Company must collect from customers in base distribution-non gas rates.

Q. How did you estimate Other Revenue for the 2026 test period?

A. Other Revenue tends to be consistent from year to year. Because the most recent historical year represents a reasonable expectation for annual revenues going forward, I used the 2024 base period revenue amounts for the 2026 test period revenue requirement calculation. That said, as discussed below, I also adjusted other revenue by $5.1 million to reduce the revenue requirement for the expected Excess Deferred Income Tax accrual during the test period.

C. Excess Deferred Income Tax Adjustment

Q. Please explain this Excess Deferred Income Taxes ("EDIT") adjustment in more detail.

A. The amortization of Excess Deferred Income Taxes impacts both income and rate base accounts each year. These EDIT amounts are the result of the changes in corporate tax rates enacted through H.R.1-An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018 ("2018 Tax Reconciliation Act"). The income component is passed through to customers as a reduction to the revenue requirement, and I have reflected this benefit by increasing Other Revenue in the test period. As this annual amortization occurs, the EDIT balance included in the 254 account is also reduced accordingly. As approved in Docket No. 19-057-02, Plant-Related EDIT amortization is recognized using the ARAM method while Other Non-Plant Related EDIT is amortized over a 12-year period. Based on this methodology, the Company has included an annual pre-tax EDIT Amortization of $3.968 million, of which $3.876 million is Utah related, as follows:

	2026 EDIT		
Description	EDIT Pre-Tax Amortization	Tax Gross Up	Total
EDIT Amortiziation - Plant Protected and Unprotected (ARAM)	3,054,855	988,756	4,043,611
EDIT Amortization - Non-Plant Related (12 Year)	912,940	295,489	1,208,429
Total EDIT Amortization	3,967,795	1,284,245	5,252,040
Description	Utah Pre-Tax Amortization	Utah Gross Up	Utah Total
UT EDIT Amortiziation - Plant Protected and Unprotected (ARAM)	2,963,209	959,093	3,922,302
UT EDIT Amortization - Non-Plant Related (12 Year)	912,940	295,489	1,208,429
UT Total EDIT Amortization	3,876,149	1,254,582	5,130,731

This results in a revenue requirement reduction of $5.13 million in the 2026 test period after grossing up for taxes. Rate base is also adjusted for 2025 and 2026 based on the annual pre-tax amounts.

Q. Is this EDIT adjustment consistent with prior rate case EDIT treatment?

A. Yes. In Docket Nos. 19-057-02 and 22-057-03, the annual EDIT amortization benefit was passed to customers as an adjustment to Other Revenue, which resulted in a reduced revenue requirement. The rate base balance in the 254 account was also adjusted accordingly as I have described.

IV. TEST PERIOD EXPENSES

Q. EGU Exhibit 4.02, Rows 9 – 13 show historical gas purchase expenses, but these expenses are not included in the test period column (column F). Why have these expenses been excluded?

A. These expenses are incurred to purchase natural gas supplies and transport those supplies to a Company receipt point. Because these types of costs are recovered through the Company's Gas Balancing Account Adjustment Provision detailed in Section 2.06 of the Company's Utah Natural Gas Tariff No. 700 ("Pass-Through Account"), I have excluded them from the test period calculation in this case.

A. Operating and Maintenance Expenses

Q. EGU Exhibit 4.02, Rows 14-21 show operating and maintenance (O&M) expenses. Please summarize what the Company is including in the test period for operating and maintenance ("O&M") expenses.

A. As shown in column B, line 21 of EGU Exhibit 4.02, the Company recognized a total of $179.04 million in O&M during the base period of 2024. This amount includes Energy Efficiency and STEP O&M expense. I have taken a series of steps to adjust historical O&M to a total of $170.7 million for the 2026 test period, as shown in Column F, as follows:

- Beginning with historical unadjusted 2024 expenses, I factored in the cost of inflation to reflect expected levels of expense by FERC account.
- I included an adjustment for corporate allocations for the latter half of the base period as Dominion Energy Services stopped allocating typical corporate costs in June of 2024, and Enbridge did not begin allocating corporate charges during the base period.
- I removed non-applicable expenses that are handled in separate dockets – specifically Energy Efficiency and STEP program expenses.

- I made several other established regulatory adjustments from prior rate cases.

Q. What approach did you use to inflate historical, unadjusted O&M expenses to the appropriate test period O&M level?

A. I followed the same methodology used in the Company's prior general rate case. First, I separated base period O&M into labor and non-labor categories. I then forecasted labor and non-labor expenses separately to arrive at the unadjusted 2026 test period O&M amount. EGU Exhibit 4.05 provides total unadjusted O&M by Federal Energy Regulatory Commission ("FERC") account for the 2024 base period, 2025 forecast, and 2026 forecasted test period, categorized by labor and non-labor expense. Labor and labor overhead make up a total of $95.9 million in unadjusted O&M expense (EGU Exhibit 4.05, column H, line 42), while non-labor O&M expenses make up the remaining $97.7 million.

Q. How did you forecast the labor and labor overhead O&M expenses?

A. Projected amounts for labor and labor overhead O&M expenses were based on the percentage increase the Company expects to pay for labor and labor overhead in 2025 and 2026 as calculated and shown in EGU Exhibit 4.06. Total forecasted labor expense is driven primarily by employee headcount and anticipated wage increases to remain competitively aligned with the labor market.

Q. How did you forecast the non-labor O&M expenses, excluding the LNG Facility?

A. The basis for the forecasted non-labor O&M expenses was the historical O&M expenses from January 2024 through December 2024. I increased or decreased the historical expenses using the 2025 inflation factors from the S&P Global Power Planner report attached as EGU Exhibit 4.07. The 2025 non-labor O&M expense and associated inflation factors are shown in EGU Exhibit 4.05, columns F and G. I then increased or decreased these 2025 expenses using the S&P Global inflation factors for 2026 to calculate the total

2026 expenses. The 2026 non-labor O&M expense and associated inflation factors are shown in columns I and J.

Q. Has the Company previously followed these steps to forecast future period O&M?

A. Yes. The approach I have outlined has been used in several of the Company's prior general rate cases, including the most recent rate case Docket No. 22-057-03. In addition, the Company uses this approach in forecasted results of operations models that are filed annually with the Commission. I have compiled forecasted O&M from these models over the past five years compared to the actual O&M for the same period in EGU Exhibit 4.08. As shown, the results of this method have slightly underestimated actual expense, with actuals averaging 102.2% of forecasted amounts from 2020-2024.

Q. Regarding corporate costs, did the sale to Enbridge during 2024 impact corporate costs allocated to the Company during the base period?

A. Yes. During the 2024 base period, the Company was sold by Dominion Energy Inc. (Dominion Energy) to an affiliate of Enbridge Energy Inc. At that time, a large portion of shared services charges from Dominion Energy dropped off, as shown in the following table:

Summary of Corporate Charges					
	2020	**2021**	**2022**	**2023**	**2024***
Q1	$12,412,196	$11,620,146	$12,358,361	$12,969,819	$12,612,943
Q2	11,193,246	10,856,932	10,921,071	11,985,509	12,051,365
Q3	10,118,132	10,819,948	11,093,215	11,875,825	7,557,504
Q4	12,038,235	12,430,479	11,872,953	12,723,242	7,122,491
Total	**$45,761,809**	**$45,727,506**	**$46,245,600**	**$49,554,395**	**$39,344,303**

*Includes departments transferred from Dominion to EGU in June 2024.

Q. Did Enbridge Inc. allocate corporate costs to EGU in 2024 when the Dominion Energy allocation ceased?

A. No. Enbridge Inc. and its affiliates did not begin to allocate corporate costs to its newly acquired distribution companies during 2024. Corporate allocations from Enbridge will begin during 2025. Because of this timing gap, the 2024 base period costs are artificially low and an adjustment is necessary to reflect a normal ongoing level that will exist during the rate-effective period.

Q. How have you adjusted corporate costs in this case?

A. I asked Enbridge Inc. to calculate the total amount of corporate allocations that would have been charged to EGU in 2024 had it pushed corporate charges down to the newly acquired distribution companies. The result is shown in EGU Exhibit 4.09, and totals $6.04 million for the 2024 base period, or $6.13 million after inflation to arrive at the 2026 test period adjustment amount. This adjustment increases the total corporate allocated costs to $46.81 million in the 2026 test period. This amount compares favorably to historical levels and represents a $4.2 million savings compared to estimated 2026 test period corporate costs that would have existed absent the sale to Enbridge.

Q. How are you calculating the $4.2 million savings figure?

A. EGU Exhibit 4.10 provides the calculation of the $4.2 million savings. I annualized the first two quarters of 2024, which represent the going level of corporate charges before the sale to Enbridge. The first two quarters of corporate charges totaled $24.66 million. This implies an annual total of $49.33 million ($24.66 X 2), which is shown in column C of Exhibit 4.10. In a hypothetical scenario where no sale took place, total corporate charges would likely have totaled this approximate amount. Adjusting for inflation, the 2026 test period would have been $51 million (Column D.), which is $4.2 million higher than the $46.81 million I have included in the test period in this docket (Column E, line 8).

Q. You mentioned previously that you also removed non-applicable expenses that are handled in separate dockets – specifically Energy Efficiency and STEP program expenses. Can you summarize this adjustment?

A. Yes. The Energy Efficiency and STEP program revenues are collected from customers through the demand-side-management and STEP amortization rates. When revenues are collected, an offsetting expense is made to the 908007 expense account. *See* Enbridge Gas

Utah's Utah Natural Gas Tariff No. 700 ("Tariff") Sections 2.09 and 2.18. These revenues are not collected through DNG rates and are not included in the 2026 projected revenue calculation. Therefore, the 2026 Energy Efficiency and STEP expenses should be removed as well. EGU Exhibit 4.11, line 13 and 26, shows the removal of these expenses.

Q. You also mentioned a series of additional adjustments based on prior rate cases. Can you specify what those adjustments are?

A. Yes. Consistent with orders in prior rate cases, I have adjusted test period O&M expense in the following ways:

- Bad debt expense was adjusted to a three-year average of DNG-related bad debt.
- As part of a dues and donations adjustment, government relations expenses were removed.
- Reserve accrual was adjusted to a five-year average payout amount.
- Pipeline Integrity Management Expense was adjusted.
- Pension related items were removed.

Q. Please explain the adjustment for bad-debt expense.

A. Bad debt expense is broken out into three components: bad debt related to DNG revenue, bad debt related to supplier non-gas revenue, and bad debt related to commodity revenue. To adjust for bad debt expense, I annualized the DNG portion of bad-debt expense forecasted to occur for the 12 months ended December 2026 to the 3-year average level of bad-debt expense. The Division of Public Utilities originally proposed this methodology in the Company's 1995 general rate case[3], and it has been the approach used in each general rate case since, including the most recent in Docket No. 22-057-03.

The calculation of this adjustment is shown on EGU Exhibit 4.12, lines 18 through 47. I divided net charge-offs for each year (line 25) by booked system revenues (line 27) to calculate a bad-debt ratio (line 30). I then used the resulting ratios for 2022, 2023 and 2024,

3 Docket No. 95-057-02

respectively, to calculate the three-year average of 0.28% in column I, line 30. After doing this, I multiplied Test-Period Utah DNG revenue of $564,113,646 (column J, line 35) by the adjusted three-year average of 0.28% (line 37) to calculate an allowed Utah DNG bad debt of $1,599,769 (line 38). The base-period system Utah DNG bad-debt expense is $3,358,239 (line 41). The base-period bad debt expense is based on booked 2024 bad debt. The resulting adjustment is a decrease to Utah expenses of $1,758,470 (line 45).

In addition to adjusting the DNG portion of bad debt as described above, I also removed the bad debt related to supplier non-gas shown on line 7 and commodity revenue on line 12 because they are accounted for in the Pass-Through Account.

Q. Please explain the governmental affairs adjustment for dues and donation.

A. In the order in Docket No. 93-057-01, the Commission prescribed the types of donations and memberships that are recoverable in rates. In the 2024 base period, the Company incurred $182,865 for government relations that was booked above the line. I updated this amount for inflation and removed it from 2026 expenses, as shown in EGU Exhibit 4.13, page 1, line 5.

Q. Please explain the insurance reserve accrual adjustment.

A. The reserve accrual includes legal liabilities associated with the Company's self-insurance program. In Docket No. 07-057-13, the Commission approved a stipulation of the parties that the allowed reserve accrual amount was to be based on the five-year average of actual payments made by the Company. Line 7 of EGU Exhibit 4.14 shows the five-year average, and line 8 reflects the actual accruals made, adjusted for inflation. The adjustment on line 10 decreases Utah expense by $74,440 for the 2026 test period amount.

Q. Please provide the background on the pipeline integrity expense.

A. On April 21, 2004, in Docket No. 04-057-03, Enbridge Gas filed with the Commission an application for a deferral accounting order authorizing it to establish an account for costs the Company would incur to remain in compliance with the new federal requirements of the Pipeline Safety Improvement Act of 2002, and the Final Rule regarding "Pipeline

Integrity Management in High Consequence Areas." On June 24, 2004, the Commission approved the application and authorized Enbridge Gas to defer the incremental gas transmission line safety compliance costs incurred on or after January 1, 2004. On June 1, 2006 in Docket No. 05-057-T01, the Commission approved the Settlement Stipulation that allowed Enbridge Gas to begin expensing a fixed amount of pipeline integrity costs. In Docket Nos. 07-057-13, 09-057-16, and 13-057-05, the Commission approved continued recovery of transmission integrity management costs.

Q. Please explain what the distribution integrity management program ("DIMP") costs are and how they are treated?

A. In Docket No. 09-057-16, the Commission approved a stipulation allowing for the deferral of the Company's DIMP costs.

The Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the Department of Transportation ("DOT") have published a rule establishing integrity management requirements for gas distribution pipeline systems. Like the Federal Pipeline Safety Regulations, this rule requires operators of gas distribution pipelines to develop and implement integrity management programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. The integrity management programs required by the rule are similar to those currently required for gas transmission pipelines, but tailored to reflect the differences in and among distribution systems. The final DIMP rule was published on December 4, 2009 and became effective February 12, 2010. Like the 2002 Pipeline Safety Act, the DIMP was federally mandated and has resulted in incremental costs.

Q. Please summarize the proposed pipeline integrity expenses going forward?

A. The amount of pipeline integrity expense included in the test period is made up of two components: 1) the anticipated level of incurred pipeline integrity expenses going forward, and 2) the amortization of the balance in the deferral account, which represents past pipeline integrity expenses that remain uncollected. The proposed ongoing expense amount is based on the actual pipeline integrity costs incurred in 2024 The following table summarizes the proposed level of expense in column C, and the change relative to the expense approved in Docket No. 22-057-03.

		A	B	C	D
		Actual 2024 Amounts	**Proposed Expense**	**Previously Approved** Docket No. 22-057-03	**Change from Previous Approved**
1	Current Expense	$11,020,687	$11,020,687	$9,431,582	$1,589,105
2	Amortization	$2,645,601	$1,745,296	$2,645,601	-$900,305
3	Total	$13,666,288	$12,765,982	$12,077,183	$688,799

As shown in column A, actual costs in 2024 were $11.02 million. The Company proposes that this be set as the current portion of amortization expense, as shown in column B. This amount is $1.59 million higher than the prior amount approved in Docket No. 22-057-03.

As of December 2024, the deferred balance was $5,235,886. This balance represents the cumulative amount that actual expenditures for pipeline integrity have exceeded the allowed annual expense level over the life of the deferred account. I am proposing that this balance be amortized over a three-year period, resulting in a $1,745,296 amortization per year, for a decrease of $900,305, as shown on row 2. The net effect of this change results in a $688,799 increase to pipeline integrity expense.

Q. What will be the accounting treatment if the Company does not incur the full amount of ongoing expenses in a given year?

A. To the extent actual ongoing expenses are less than $11.02 million per year, the difference will continue to be credited to the deferred account.[4] To the extent actual ongoing expenses

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4 In Docket No. 04-057-03, the Commission approved the application and authorized Enbridge Gas Utah to defer the incremental gas transmission line safety compliance costs incurred on or after January 1, 2004. In Docket No. 09-057-16, the Commission approved a stipulation allowing for the deferral of the Company's DIMP costs.

are greater than $11.02 million, the difference will continue to be debited to the deferred account.

Q. Is the Company proposing changes to the way Pension related activity is treated in the revenue requirement?

A. No. In Docket No. 19-057-02, the Commission approved the exclusion of certain pension-related items from the Company's revenue requirement. This includes the pension asset in account 186, the pension-related deferred income tax amount in account 282, and the corresponding pension credit in O&M expense. I have removed these items from the 2026 test period. The total adjustments are shown in EGU Exhibit 4.15.

Q. Did you make any additional adjustments to test period expense that have not yet been discussed?

A. No. That said, I would like to note that in prior cases the Company has adjusted expenses for sporting event tickets and advertising. I'd like to briefly explain each of these.

Pursuant to the Commission order in Docket No. 99-057-20, the Company has historically removed from its test period the portion of expense for sporting event tickets that are not used for employee recognition. In 2024, all sporting event expenditures were used for employee recognition, and as such no adjustment has been made.

Related to advertising expenses, consistent with the Commission order in Docket No. 93-057-01, and in general rate cases since 1993, the Company has consistently decreased expenses in the test period by removing advertising expenses related to promotional and institutional advertising. In the 2024 base period, there was no promotional or institutional advertising expense incurred by EGU or allocated to EGU from its parent Company. As a result there were no promotional or institutional advertising expenses in the test period. Thus, no adjustment was necessary to account for such expenses.

Finally, in prior cases dating back to Docket No. 93-057-01, the Company has removed the financial portion of incentive expense from the test period. In this docket, I have elected not to remove this expense and propose that the full incentive remain in rates.

Q. Why should the Company's full annual incentive program be recoverable in rates?

A. Dating back to the early 1990s, the Company has removed, for ratemaking purposes, incentive-compensation expenses related earnings goals either paid directly by Enbridge Gas or allocated from corporate affiliates for incentive payouts. To the best of my knowledge, the underlying rationale behind this treatment for the Company has not been thoroughly reviewed or discussed in general rate case proceedings since that time. Conditions have changed considerably over the last three decades, as I will discuss further below. As currently constituted, the EGU incentive plans included in the 2026 test period are just, reasonable, and in the public interest and should remain in the Company's revenue requirement calculation.

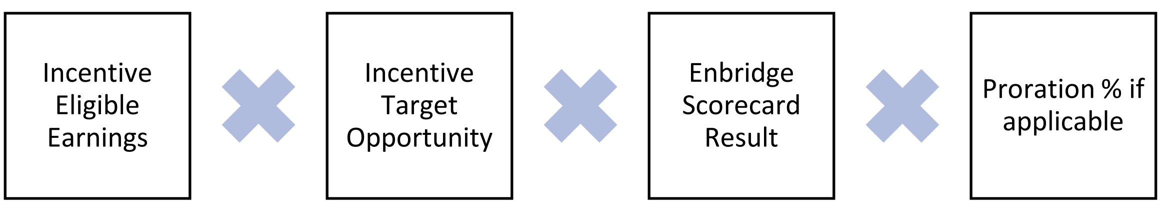
Q. Why do current conditions merit a change in the treatment of incentive expenses?

A. Today, the Company's incentive plans are a critical part of an overall compensation package that, in the aggregate, are aligned with the labor market and allows the Company to attract and retain employees. They also serve to foster engagement and high performance. As currently designed, the Enbridge incentive plan effectively sets a portion of the market-based compensation package to an "at-risk" status. This means that if employees achieve the designed targets, then overall compensation including the incentive payments would be aligned with market based compensation amounts. If performance falls below targets, then the compensation would reflect that as the at-risk portion of compensation shrinks accordingly. The plan also includes an opportunity for employees to exceed expectations, in which case an employee's compensation can exceed the market.

Q. Please provide more detail regarding the Enbridge plan.

A. Attached as EGU Exhibit 4.16 is the 2024 and 2025 short-term incentive plans for Enbridge. Page one of these documents provides an overview of the plan and the scorecard measures for performance. As described under the plan overview, the incentive opportunity for each, referred to as the "target incentive opportunity", is role-based and expressed as a percentage of base pay. It is also market based, explained as follows: "These incentive targets are set to ensure your total cash compensation (base pay + incentive) is competitive to support Enbridge as an employer of choice. This means, when we hit our targets, your pay is aligned to what you would receive at a competitor organization with the same results. Higher performance results in higher total cash compensation resulting in better than market pay and supports our pay for performance philosophy."

Page two provides the scorecard for that year, and the weighting assigned to each measure. As shown, measures include Enterprise Financial, Safety, Project Performance, Emissions, Cyber Security, and Business Unit Earnings. The Enterprise Financial measure uses Distributable Cash Flow, and the Business Unit Earnings measure uses Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). As noted under the scorecard on page 2, each measure has a defined minimum (0.00x), target (1.00x), and maximum (2.00x) performance goals tied to achievement levels. Page 3 provides each employees incentive calculation as follows:



Q. **In the labor forecast for the 2026 test period, do the amounts assume that performance and incentive compensation will be on target?**

A. Yes. The labor forecast assumes that future period incentive payments will be on target, meaning that the test period includes a market based compensation for total labor. If employees exceed expectations and earnings increase above the target, then any additional incentive payments that exceed the market based average are effectively excluded from rates and are shareholder funded.

Q. Are the financial portion of incentive payments consistent with customer interests?

A. Yes. As the Company's plans are currently designed and especially in the current environment in which it operates, the measure benefits both the Company and customers. Attracting and retaining high quality employees is an essential part of operating a safe and reliable utility service. Including in rates the market-based compensation package that allows the Company to operate, while excluding the "above market" earning potential from the 2026 test period, strikes an appropriate balance.

In addition, the way the Company earns income today is significantly different from the early 1990s. Today the Company's revenues are decoupled from customer usage. Company earnings are no longer impacted by a throughput maximizing mentality. In today's environment, the best way to attain earnings is to operate efficiently, find ways to control costs, and be responsive and agile in meeting service requests from new customers. These interests align well with the public interest overall. As stated on the bottom of page one of the incentive plans in EGU Exhibit 4.16: "Not all roles directly affect revenue generation, but all roles can affect expenses. For example, taking advantage of early booking travel discounts or video conferencing reduces business travel expense." In the case of Enbridge Gas Utah, one effect of revenue decoupling is that operating efficiently and controlling costs are the primary ways that employees can impact earnings in a given year, something that benefits customers in the form of reduced O&M in general rate case proceedings.

Q. Please provide more detail on how the financial metrics are achieved by controlling costs due to decoupling.

A. During the 1990s, the net income for the Company could be driven by increasing sales. If throughput at the utility increased, revenue and net income would also increase, benefitting shareholders. While one could make the case that an indirect benefit existed for customers as more volumes reduced the per-unit cost of natural gas on the system, this indirect benefit was largely viewed as inadequate to justify rate recovery for net-income related goals.

Because of the CET and revenue decoupling, net income is no longer impacted by increasing throughput at the utility. The link between throughput and net income is broken, as explained in the Direct Testimony of Kelly B Mendenhall. Now, the sole lever available to employees to achieve a net-income goal is to prudently manage costs and operate efficiently. This is an entirely new paradigm that didn't exist when the incentive adjustment was initially adopted. In today's environment, the incentive aligns with interests of both customers and the Company.

B. Depreciation Expense

Q. Is the Company recommending changes to the depreciation rates in this case based on an updated depreciation study?

A. Yes. In the Revenue Requirement Stipulation in Docket No. 07-057-13, the Company agreed to perform a new depreciation study every five years on a going-forward basis. In Docket No. 19-057-03, the Company submitted a study performed by the third-party depreciation consultant Gannett Fleming based on 2017 plant balances. On June 26, 2019, parties filed a Settlement Stipulation with changes to the originally proposed depreciation rates. In this case, the Company submits a new depreciation study conducted by Gannett Fleming based on 2022 plant balances. This is attached as EGU Exhibit 4.17.

Q. Is the Company recommending that these new depreciation rates be incorporated into base rates and become effective January 1, 2026?

A. Yes.

Q. Please explain the depreciation adjustment.

A. I have prepared a comparison of 2026 depreciation expense under the current depreciation rates and the proposed update to depreciation rates, provided as EGU Exhibit 4.18.

Columns B-C show the depreciation rates and expense based on the approved 2017 depreciation study. Columns D-E show the proposed depreciation rates and expense that would be incurred under the new 2022 depreciation study. Column F provides the total change in depreciation expense by FERC account as a result of the change in depreciation rates. As shown on line 140, total depreciation expense changes by approximately $25 million in the 2026 test period. A thorough analysis and discussion of this proposed change is included in the study conducted by Gannett Flemming and attached as EGU Exhibit 4.17.

C. Other Operating Expenses

Q. EGU Exhibit 4.02, row 24, includes Taxes Other Than Income Taxes. How did the Company forecast Taxes Other Than Income Taxes?

A. The detail for this forecast is shown in EGU Exhibit 4.19. Total other taxes for 2026 are expected to be approximately $38.2 million, mainly made up of property taxes (line 1). EGU's assessed property valuation has increased due to increased capital additions. Other taxes in this category include gross receipts taxes, payroll taxes, utility revenue franchise taxes, and other taxes as shown on rows 2 through 5.

Q. EGU Exhibit 4.02, row 25, includes Income Taxes. How are test period income taxes calculated?

A. Consistent with prior rate case dockets, I have imputed the appropriate income tax amount based on current state and federal income tax rates. EGU Exhibit 4.20 shows three methods the Company has consistently utilized to calculate the appropriate income tax amount to collect in the revenue requirement. The three methods are the algebraic method, the rate base method, and the operating income method. Each of the three methods result in an imputed income tax of $30.7 million for the 2026 test period.

V. TEST PERIOD RATE BASE

A. Net Plant-in-Service

Q. EGU Exhibit 4.02, rows 30 – 37, provides net plant balances. Please explain how this portion of rate base was projected for the test period.

A. I calculated the projected Gas Plant in Service (Accounts 101/106) balances starting with actual December 2024 balances (EGU Exhibit 4.21, column A), as this is the most recently available actual annual data. I then added the net 2025 capital additions (column B) to calculate the projected December 2025 balance (column C). I then added the 2026 net additions (column D) to the December 2025 balance to calculate the December 2026 balance (column E).

EGU Exhibit 4.22, page 1, shows the calculation of the net additions for 2025. I took the $389 million capital budget by FERC account for 2025 (EGU Exhibit 4.22, page 1, column A), and I removed the retirements expected to occur during 2025 (column B). Last, I added the amounts in the Construction Work in Progress (Account 107) and Completed Construction Not Classified (Account 106) at the end of 2024 that will be closed in 2025 (column C) and removed the 2025 expenditures expected to be in Construction Work in Progress at the end of the year (column D). The sum of columns A through D is the 2025 net additions, shown in column E. After doing this, I added the 2025 net additions to the 2024 plant balances by FERC account to arrive at a December 2025 balance. I took the same steps in EGU Exhibit 4.22, page 2, columns A through E, to arrive at December 31, 2026 Gas Plant in Service balances.

I have also projected that the Accumulated Depreciation, Amortization, and Asset Retirement Cost (Accounts 108, 111, and 254) will increase by $208.2 million between December 2024 and December 2026 resulting in an ending balance of $1.3 billion for the test year (EGU Exhibit 4.23, column E, line 12). This increase is due primarily to annual depreciation expense, which increases each year as plant-in-service increases. I have also adjusted the 108 account balance for anticipated retirements, proceeds, and dismantling activity through 2026. Account 254 – Other Regulatory Liabilities has amounts associated with depreciation expense of future removal costs and will also change as assets are depreciated. The total depreciation expense booked to the 254 account is shown on line 11 of EGU Exhibit 4.23.

Q. How did you estimate the impact of retirements, proceeds, and dismantling costs in the 108 account?

A. For retirements, I used the 5-year average historical retirement amounts as an estimate for ongoing annual retirements to occur in 2025 and 2026. Proceeds and dismantling, or net salvage, are related to retirements. To estimate proceeds and dismantling amounts, I calculated a five-year average ratio over total retirement dollars through 2024. I then applied that ratio to the anticipated 2025 and 2026 retirement dollars to derive estimated proceeds and dismantling costs.

Q. You stated that you used the capital budget to forecast the plant for the year ended December 2026. How accurate have the Company's capital budget forecasts been in the past?

A. EGU Exhibit 4.24 shows the capital budget for the last five years compared to actual expenditures. As shown on line 6 of the exhibit, actual capital expenditures have been 2.7% above budget on average, with 2023 seeing the largest variance. The variance that year was largely driven by a timing mismatch between capital contributions and capital expenditures. Laying aside 2023, the Company's budget has been within 1% on average.

Q. What type of activity makes up the capital budgets in 2025 and 2026?

A. EGU Exhibit 4.25 provides a high-level capital budget summary for 2025 and 2026. EGU Exhibit 4.26 provides a detailed schedule of capital projects. A large portion of the capital budget is made up of ongoing required programs. These include items such as new or replaced mains, service lines, risers (the connection from a service line to a meter), valves and meters.

With over one million customers and a sprawling network of mains and services spread across the state, many of these capital activities are not specified to individual projects or customers, but are rather tracked as a program with total costs in a year budgeted using historical data, expected customer growth, and consultation with procurement, construction managers, etc. These are ongoing annual capital budget programs that do not lend themselves to a specific project or location but are more broadly undertaken across the Company's service territory as required to serve new customers and ensure a safe and reliable system.

The capital budget also includes larger individual projects which are included in EGU Exhibit 4.26. The 2026 budget is based on 2025 activity, with adjustments for known changes between 2025 and 2026. For example, the amount of 2026 spending on feeder line projects is reduced because a large phase of the Company's southern system reinforcement project will be completed in 2025. Total spending on meter and meter installation projects are also expected to decrease as large industrial meter installation investment is completed in 2025. Other categories and projects are largely consistent with the 2025 budget and reflect anticipated ongoing capital requirements. All told, the 2026 capital budget falls from $389M in 2025 to $332.6M in 2026 (see EGU Exhibit 4.25).

B. Other Rate Base Accounts

Q. EGU Exhibit 4.02, rows 38-51, provide various other rate base accounts. Please explain how these items were projected for the test period.

A. Several of the 2026 balances in this category are carried forward from historical base period 2024 amounts. This is the case for the 154, 190008, 190009, 235-1, and 252 account balances.

I calculated the deferred income taxes account balances (Account 282) for 2025 and 2026 by taking projected investment, depreciation, and tax amounts and projecting their impact on deferred income taxes, consistent with the Company's methodology in Docket No. 19-057-02 and with Commission precedent (see EGU Exhibit 4.27, line 5).

I removed all pension related rate base items from the test period as discussed previously in my testimony and consistent with the Commission order in Docket No. 19-057-02.

Finally, I included a rate base adjustment for cash working capital that reflects the amount of cash required by the Company to meet daily cash operating needs. The methodology of calculating this rate base item is consistent with prior rate cases and relies on a lead-lag factor supported by a detailed lead-lag study.

Q. In Docket No. 22-057-03, the Company used a Lead-Lag study based on 2021 data. Have you updated your Lead-Lag study in this case?

A. Yes. The Company is using an updated Lead-Lag study based on 2023 data. I have attached the updated study as EGU Exhibit 4.28. The Commission-approved stipulation in Docket No. 07-057-13 requires the Company to use a lead-lag study in which the end date of the period used for the study is not more than three years old at the time of the filing. The end date of the 2023 study will be less than three years old at the time of this filing.

Q. Did the Company make any changes to the Lead-Lag methodology between the 2023 study and the previous study?

A. The Company used the methodology approved by the Commission in its order in Docket No. 19-052-02. Most notably, the Company excluded depreciation and deferred income tax items from the study consistent with the Commission's directive in that final order. The remaining components of the study remain consistent with prior lead-lag studies.

Q. Please explain how the Lead-Lag study affects cash working capital.

A. Cash working capital is defined as the amount of cash needed on hand by a utility to pay its daily operating expenses for the period between the time it provides services to its customers and the time it receives payment for those services. If, on average, the time to collect revenues for services exceeds the time to pay the expenses for those services, the utility is experiencing a positive "net revenue lag," which requires cash on hand. If, on the other hand, the lag to pay expenses is longer than the lag to collect revenues, it is experiencing a negative "net revenue lag."

Q. Please summarize the results of the 2023 lead lag study?

A. The study shows that revenue was collected 45.807 days from the time of recognition. Expenses were paid approximately 38.294 days following recognition, for an overall net lag calculation of 7.513 days. This is a decrease from the 8.35 that was approved in the last general rate case. The use of this calculated lag results in a test-year cash working capital requirement of $23.96 million (EGU Exhibit 4.02, column F, line 50).

Q. Did you make any additional adjustments to rate base that have not yet been discussed?

A. Yes. Consistent with prior rate case orders, I have made adjustments related to gas stored underground and the Wexpro production plant balances.

Q. Please explain the adjustment for Gas Stored Underground.

A. Pursuant to the final order in Docket No. 93-057-01, Account 164, Gas Stored Underground - Current, is to be accounted for in the Company's Pass-Through Account cases and excluded from test-year rate base. This is accomplished in Pass-Through Account cases by allowing a return on the actual average balance in this account to be entered as a gas cost in the 191 Account. This adjustment removes the total balance of Account 164 from the rate-base calculation. EGU Exhibit 4.29 summarizes this adjustment.

Q. Please explain the adjustment for Wexpro investment.

A. In accordance with the Wexpro Agreement, Wexpro adds 6.3% of EGU's production plant to the Wexpro investment as a general plant allowance when calculating the Wexpro service fee charged to EGU. The Wexpro Agreement also provides that the production plant component in each EGU's rate base plant account should be reduced by 6.3%. This adjustment will continue to decrease over time as this plant fully depreciates. EGU Exhibit 4.30 summarizes this adjustment.

Q. You have discussed numerous adjustments to 2024 historical revenue, expense, and rate base amounts to calculate 2026 test period conditions. Have you prepared a summary of adjustments?

A. Yes. Attached as EGU Exhibit 4.31 is a summary of each adjustment I have made to historical 2024 amounts to arrive at test period 2026 amounts. Each adjustment is shown in its own column, with the total of all adjustments shown in the last column. The total of all adjustments on this summary matches the adjustment amount shown in column C of EGU Exhibit 4.02.

VI. COST OF CAPTIAL

Q. What is the cost of debt included in the average 2026 test period?

A. The Company has included a cost of debt of 4.25% in the 2026 test period. The 2026 cost of debt is based on current rates of outstanding issuances of debt. EGU Exhibit 4.32 provides a more detailed breakdown of the components of debt and the cost of debt for the 2023 and 2024 average historical years (columns A and B), and the average 2026 test period (column C).

Q. What is the cost of equity included in the average 2026 test period?

A. The Company has included a cost of equity of 10.6% in the 2026 test period. This is discussed more thoroughly in the Direct Testimony of Company witness Jennifer Nelson.

Q. Please provide the capital structure and total cost of capital EGU is proposing for the 2026 test period.

A. The Company is proposing an average capital structure for 2026 that consists of 53% equity and 47% debt. This forecasted capital structure is lower than the actual historical capital structure the Company has experienced over the last couple of years. At a cost of equity of 10.6% and cost of debt at 4.25%, this results in a weighted average cost-of-capital of 7.61%, as shown in the following table:

	AVG CAP STR DEC 26		Weighted
	Weight	Cost	Cost
Long Term Debt	47.00%	4.25%	2.00%
Common Equity	53.00%	10.60%	5.62%
	100.00%		7.61%

The proposed capital structure is discussed more thoroughly in the Direct Testimony of Warren Reinisch.

VII. PROJECTED DEFICIENCY AND REVENUE REQUIREMENT

Q. Have you calculated a total revenue requirement for this case?

A. Yes. Based on the projected capital structure and a 10.6% return on equity incorporated together with the forecasted data and regulatory adjustments, I calculated the total Utah revenue requirement to be $656.6 million. (EGU Exhibit 4.02, column H, line 3).

Q. Using the current allowed revenue per customer, what is the projected revenue deficiency for the test period?

A. EGU Exhibit 4.02 shows that, for the proposed test period, the Utah operations of the Company would be expected to earn 5.55% return on equity. This results in a revenue deficiency of $114.7 million (column G, line 3).

Q. Have you made a similar calculation of the revenue deficiency using volumetric revenues for the GS class instead of the allowed revenue-per-customer?

A. Yes. EGU Exhibit 4.33 shows that, for the test year, the Utah operations of the Company would be expected to earn 5.58% return on equity during the rate-effective period, absent rate relief in this docket. This amounts to a revenue deficiency of $114.1 million.

Q. Does the difference cause the total revenue requirement to change?

A. No. The allowed revenue requirement does not change. A summary of the two calculations is shown in the following table:

	Current Revenue	Deficiency	Revenue Requirement
CET Allowed Revenue	$542.0 Million	$114.7 Million	$656.6 Million
Volumetric Revenue	$542.5 Million	$114.1 Million	$656.6 Million

Rates will be set on the total revenue requirement, not the deficiency, thus, the end results will be the same regardless of how one calculates revenue deficiency.

Q. Does that conclude your testimony?

A. Yes.

State of Utah)
) ss.
County of Salt Lake)

I, Jordan K. Stephenson, 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.

Jordan K. Stephenson

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