PASS-THROUGH APPLICATION OF ENBRIDGE GAS UTAH FOR AN ADJUSTMENT IN RATES AND CHARGES FOR NATURAL GAS SERVICE IN UTAH	)))))	 Docket No. 24-057-16 VERIFIED APPLICATION

All communications with respect to
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APPLICATION
AND
EXHIBITS

October 1, 2024

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- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

PASS-THROUGH APPLICATION	)	
OF ENBRIDGE GAS UTAH FOR	)	Docket No. 24-057-16
AN ADJUSTMENT IN RATES AND	)	
CHARGES FOR NATURAL GAS	)	
SERVICE IN UTAH	)	VERIFIED APPLICATION

Questar Gas Company dba Enbridge Gas Utah ("Enbridge Gas" the "Company") respectfully requests Utah Public Service Commission ("Commission") approval of this Verified Application ("Application") for a decrease of $39,563,164 in its Utah natural gas rates. The driving force behind the price decrease requested in this Application is lower commodity prices for the test period. The information contained in this Application reflects Utah gas costs of $608,417,569. Therefore, a typical residential customer using 70 dekatherms per year will see a decrease in their total annual bill of $22.82 (or 3.45%).

In support of this Application, Enbridge Gas states:

1. Enbridge Gas Operations. Enbridge Gas, a Utah corporation, is a public utility engaged in the distribution of natural gas primarily to customers in the states of Utah and Wyoming. Its Utah public utility activities are regulated by the Utah Public Service Commission, and the Company's rates, charges, and general conditions for natural gas service in Utah are set forth in the Company's Utah Natural Gas Tariff No. 700 ("Tariff"). Copies of the Company's Articles of Incorporation are on file with the Commission. In addition, the Company serves

customers in Franklin County, Idaho. The rates for these Idaho customers are determined by the Utah Commission pursuant to an agreement between the Commission and the Idaho Public Utilities Commission. Volumes for these customers have been included in the Utah volumes.

2. Applicable Statutes. The Commission may grant relief requested in this case pursuant to its general authority pursuant to Utah Code Ann. § 54-4-1 and the energy balancing account authority embodied in Utah Code Ann. § 54-7-13.5 (2023).

3. Tariff Provision. The Commission has authorized Enbridge Gas to implement Account No. 191 of the Uniform System of Accounts to balance its gas costs with revenues. This filing is made under §2.06 of the Tariff, pages 2-9 through 2-14, which sets forth procedures for recovering gas costs shown in Account No. 191 by means of periodic and special adjustments to rates and an amortization of that account over one year. Pursuant to the Order Approving Dominion Energy's Modifications to Tariff Section 2.06 in Docket No. 19-057-T01, this Application categorizes costs based upon updated definitions of Supplier Non-Gas ("SNG") and Commodity costs.

4. Test Year. The test year for this Application is based on expected sales transportation, and storage for the 12 months ending October 31, 2025. EGU Exhibit 1.01 page 2 allocates system-wide costs to Utah and Wyoming jurisdictions on the basis of either peak-day demand or commodity sales, as appropriate. The Company's Liquified Natural Gas facility (LNG facility) will only serve the Utah jurisdiction, and therefore costs associated with the LNG facility are directly assigned to Utah. The result of all of the allocations discussed in this paragraph is $608,417,569 in gas costs for Utah (EGU Exhibit 1.01 page 2, line 21).

5. Cost-of-Service Production. EGU Exhibit 1.02 page 1 shows the expected test-year costs for gas produced for Enbridge Gas by Wexpro Company ("Wexpro") under the Wexpro I and Wexpro II Agreements. System-wide, total costs for this production are expected to be $255,330,302, as shown on line 13. These costs comprise the following elements:

a. Royalty Payments. During the test year, Enbridge Gas will make royalty payments of $22,506,569 (EGU Exhibit 1.02, page 1, line 3) on Company-owned gas produced under Wexpro I and royalty payments of $12,246,306 (EGU Exhibit 1.02, page 1, line 8) on Wexpro II production. These royalty payments are based on projected well head volumes for the test year and the price forecast for the test year explained below in paragraph 11.

b. Operator Service Fee. Enbridge Gas pays Wexpro an operator service fee for operating cost-of-service wells pursuant to the Wexpro I and Wexpro II agreements and applicable settlement agreements. The Wexpro I operator service fee for gas produced from productive gas wells for Enbridge Gas by Wexpro is expected to be $149,594,906 (EGU Exhibit 1.02, page 1, line 4). The operator service fee for Wexpro II is expected to be $70,982,520 (EGU Exhibit 1.02, page 1, line 9).

c. EGU Exhibit 1.02, page 2, shows other revenues that are treated as direct credits to gas costs, as required by the Commission in its Order in Docket No. 80-057-10 and as revised by Commission Order in Docket No. 01-057-14. Other revenues of $26,637,530 are the forecasted amounts for the 12 months of the test year as shown on EGU Exhibit 1.02, page 2, line 21. There are no anticipated credits for sales of gas under the Wexpro II Trail Unit Stipulation[1] in this test period (line 20).

6. Summary of Gas-Related Gas Costs. EGU Exhibit 1.02, page 3 summarizes Enbridge Gas Wexpro's total gas costs by component. The total forecasted costs and volumes for Wexpro I, Wexpro II, and in total are shown on lines 8, 13, and 20, respectively.

a. Gathering Charges. Gathering charges are computed on the basis of forecasted production and gathering volumes for the test period. A portion of Wexpro I gathering services and the costs of that gathering continue to be provided under the terms of the 1993 system-wide gathering agreement as amended ("Gathering Agreement"). Other gathering charges associated with Wexpro I are $1,404,939 (EGU Exhibit 1.02, page 3, line 6). Wexpro II volumes are gathered under a separate agreement and are estimated to be $350,475 (EGU Exhibit 1.02, page 3, line 12). Wexpro acquired the majority of the Wexpro II gathering system in November 2021. Charges for the use of these systems had previously been included and shown as gathering

[1] The Commission approved the Wexpro II Trail Unit Stipulation in Docket No. 13-057-13.

charges. Costs associated with the gathering systems are now included in the Wexpro II operator service fee.

7. Purchased Gas Costs. Enbridge Gas' total purchased gas costs are calculated to be $307,862,545 as shown in EGU Exhibit 1.02, page 4, line 6. For this test year, purchased gas costs are projected to average $4.35353. These costs are based on projected gas purchase volumes, existing contract terms, projected contracts, and a forecast of gas prices. In this case, the Company has used an average of gas-price forecasts from the S&P Global Platts Forecast and Platts NYMEX Forward Curve. These purchased gas costs comprise the following elements:

a. Enbridge Gas currently expects to purchase 38,033,000 Dths through purchase contracts at a total cost of $205,318,900 as shown in EGU Exhibit 1.02, page 4, line 3.

b. In addition to purchase contracts, Enbridge Gas anticipates buying 29,635,626 Dths on the spot market at a total estimated cost of $92,818,465 (EGU Exhibit 1.02, page 4, line 4).

c. Also, Enbridge Gas expects to contract in the future for an additional 3,046,946 Dths at a total estimated cost of $9,725,180 as shown on EGU Exhibit 1.02, page 4, line 5.

8. Storage Adjustment. EGU Exhibit 1.02, page 5, line 3 shows an adjustment that is made to commodity prices due to the temporary difference between when gas is injected into and withdrawn from storage. This adjustment fluctuates due to seasonal timing of injections and withdrawals, along with the seasonal costs of gas going into and out of storage.

9. Working Storage Gas. The return on working storage gas for the most recent 12 months is $3,096,258 (EGU Exhibit 1.02, page 5, line 17).

10. LNG. The Company's voluntary request for pre-approval of its resource decision to construct the LNG facility was approved by the Commission in an Order in Docket No. 19-057-13. The LNG facility will provide additional gas supply reliability in the 2024-2025 winter heating season. The costs related to the LNG facility will be recovered by the General Service (GS) and Firm Sales Service (FS) customers in general rates. The commodity-related LNG costs

will be recovered from GS and FS customers in this Application and comprise the following elements:

a. LNG Purchased Gas. The LNG tank will be filled in the test period for a total cost of $688,631 as shown in EGU Exhibit 1.02, page 6, line 1.

b. LNG Storage Adjustment. EGU Exhibit 1.02, page 6, line 4 shows an adjustment that is made to commodity prices due to the temporary difference between when gas is injected into and subsequently withdrawn from the LNG tank for a total adjustment of $414,399 as shown in EGU Exhibit 1.02, page 6, line 4. This adjustment fluctuates due to seasonal timing of injections and withdrawals, along with the seasonal costs of gas going into and out of storage. The withdrawals shown are for 15% of the tank volume that must be vaporized each year to cycle the tank to ensure the heat content of the LNG remains within the Company's Wobbe limit.

c. LNG Working Storage Gas Charges. The return on working storage gas balance is estimated to total for the test period $388,478 (EGU Exhibit 1.02, page 6, line 18).

11. Forecasted Gas Cost Comparison. EGU Confidential Exhibit 1.03 provides a comparison of the gas price forecasts, as well as the average of the forecasts, for the test year.

12. Transportation. Enbridge Gas incurs system-wide charges for transportation of gas to its distribution system. The transportation, storage, and peak hour service costs are based on upstream pipelines' rates. These costs are calculated to be $73,976,636, as shown in EGU Exhibit 1.04, page 1, line 30. These costs include the following elements:

a. MountainWest Pipeline (MWP), MountainWest Overthrust Pipeline (MWOP), and Kern River Gas Transmission Company (Kern River) Demand Rates. Annual transportation demand charges to transport produced and purchased gas are calculated to be $68,078,255 system-wide (EGU Exhibit 1.04, page 1, line 15). This includes a capacity release credit of $2,871,023 (EGU Exhibit 1.04, page 1, line 5). The Company's contract with MWOP totals $154,269 (EGU Exhibit 1.04, page 1, line 7). This contract extends the path of capacity on an existing contract with MWP. This contract allows the Company to purchase gas at a more convenient location and transport it to the receipt point on a MWP contract.

b. MWP, MWOP, and Kern River Commodity Rates. The transportation volumes in this Application reflect the level of Wexpro I and Wexpro II production and purchased-contract gas transported during the test year and current FERC approved rates. Transportation commodity charges are calculated to be $597,457 (EGU Exhibit 1.04, page 1, line 25).

c. Peak Hour Service. Peak-hour demand is the demand occurring during the hours during the day when total customer usage is at its highest. Design-Day demand calculates the total usage flowed during a 24-hour period (day), while the peak-hour demand is the maximum flow rate during that day. The upstream pipelines that serve the Company can only meet those usage levels above the Design-Day Demand on an operationally available (interruptible) basis. To guarantee firm service during peak-hour, Enbridge Gas' most recent agreement with Kern River provides peak-hour services for a cost of $1,388,457 (EGU Exhibit 1.04, page 1, line 27). Enbridge Gas' most recent agreement with MWP provides peak-hour services for a cost of $1,630,162 (EGU Exhibit 1.04, page 2, line 28).

13. Storage Charges. Dominion Energy also incurs system-wide storage and working gas charges for gas to be delivered during the winter heating season. These costs are $19,255,950 as shown in DEU Exhibit 1.04, page 2, line 13. The components of these costs are the following:

a. Storage Demand. The demand component of storage is calculated to be $18,825,058 (DEU Exhibit 1.04, page 2, line 5).

b. Storage Commodity. The charges during the test year for injections to and withdrawals from aquifer peaking, Spire, and Clay Basin storage fields are calculated to be $430,892 (EGU Exhibit 1.04, page 2, line 12).

14. LNG Storage-Related Electricity Costs. The process of liquifying natural gas requires electricity. Electric costs will fluctuate with the liquefaction of natural gas for storage into the LNG tank. Because these costs are directly related to the amount of gas that needs to be liquified each year, they could be highly variable from year to year. Additionally, the rate paid for these electricity costs could also fluctuate from year to year. These costs will be included in the 191 Account as stated in the July 28, 2022, Order in Docket No. 22-057-08. For the test year,

electricity costs of the LNG plant are estimated to be $2,535,680 (EGU Exhibit 1.04, page 2, line 14). This number is calculated using actual electric costs for the historical year.

15. Supplier Non-Gas Cost Class Allocation. In the Report and Order dated February 25, 2020 in Docket No. 19-057-02, the Commission approved a new method for allocating supplier non-gas costs to customers. This method allocates peak hour contract costs to transportation customers. EGU Exhibit 1.04, page 3, shows the allocation of SNG costs to all classes, as approved in that order.

16. Unit Commodity Cost in Rates. EGU Exhibit 1.05, page 1, shows the derivation of gas commodity unit costs to be reflected in Enbridge Gas' rate schedules. The portion of expected test-year gas costs to be recovered on a commodity basis is $513,886,408 (EGU Exhibit 1.05, page 1, line 1) and LNG Costs to be recovered by the GS and FS rate classes on a commodity basis is $1,491,508 (EGU Exhibit 1.05, page 1, line 2). The corresponding unit cost of gas applicable to Utah rates for GS and FS customers is $4.25170/Dth (EGU Exhibit 1.05, page 1, line 8). The unit cost of gas for Interruptible Sales (IS) and Natural Gas Vehicle (NGV) customers is $4.23935 (EGU Exhibit 1.05, page 1, line 11 and 14).

17. Amortization of Commodity Portion of 191 Account Balance. In the first pass through filing of 2024, Docket No. 24-057-09, the Company removed the amortization and reset the amortization rate to $0.00000 (EGU Exhibit 1.05, page 1, lines 9, 12, and 15, column E). The actual August 31, 2024 191 Account commodity portion is over-collected by $37,902,568. The Company would usually amortize this balance by implementing a credit amortization rate. However, due to unpredictable pricing events happening more frequently in recent years, instead of establishing a credit amortization, the Company is proposing to keep the amortization rate set at $0.00000 to help avoid unnecessary rate volatility and increase rate stabilization. The Tariff states in Section 2.06, Surcharge Rate Determination, "No less frequently than annually, the Company will file with the Commission an application for establishment of a surcharge rate (positive or negative) to amortize both the commodity cost balance and supplier non-gas cost balance portions of the unrecovered purchased gas costs in Account 191.1." Therefore, the

Company is proposing to continue the amortization rate at $0.00000 established in the previous pass-through case (EGU Exhibit 1.05, page 1, lines 9, 12, and 15, column D). The Company will continue to monitor the balance and file for an adjustment to the commodity amortization prior to the typical spring pass-through filing if circumstances deem appropriate. The Company will also continue to pay customers interest on the over-collected balance.

18. Net Unit Commodity Cost. The net result of the changes in gas costs, summarized in paragraph 16, and the 191 Account amortization discussed in paragraph 17 yields a unit commodity cost of $4.25170/Dth for GS and FS customers, a decrease of $0.34003/Dth (EGU Exhibit 1.05, page 1, line 10). Since IS customers do not pay for LNG costs, the unit commodity rate for the IS class is $4.23935/Dth, a decrease of $0.34184/Dth (EGU Exhibit 1.05, page 1, line 13).

19. RIN (Renewable Identification Numbers) Proceeds from CNG. The Order issued on October 30, 2020, in Docket No. 20-057-14 directed the Company "to continue to evaluate other methods to more transparently account for the NGV RIN credit in the 191 Account model, rather than the method it used in this case in which it recognized the credit through the commodity portion of the test year forecast." The Company has evaluated and changed the method of handling the RIN proceeds to be recognized in the amortization rate rather than the commodity rate. This treats the RIN proceeds similar to other known, or historical costs. In Docket No. 24-057-09, RIN proceeds were generated through RNG (renewable natural gas) sales at the Company's CNG Stations. The RIN proceeds totaled $263,699 (EGU Exhibit 1.05, page 1, footnote 4). A total of $69,974 is expected to be amortized by November 1, 2024 with an amount of $193,725 remaining to be amortized. In addition, new RIN proceeds have been received from May to August 2024 totaling $74,383. The sum of remaining RIN proceeds and new RIN proceeds results in a total of $268,108 of RIN proceeds ($193,725 + $74,383) to be amortized over the test period. A credit of $1.34766 will reduce the commodity cost for NGV customers yielding a unit commodity cost of $2.89169 (EGU Exhibit 1.05, page 6, line 10, column B).

20. Supplier Non-Gas Costs. Since mid-1984, Enbridge Gas' rate structure has incorporated a supplier non-gas component that reflects suppliers' non-gas costs billed to Enbridge Gas. The Company has been tracking this supplier non-gas component of its Account No. 191 pursuant to the terms of its Tariff. The base test-year supplier non-gas costs are $93,039,653 (EGU Exhibit 1.05, page 2, line 1).

a. Net Unit SNG Cost. Current rates, including the amortization, are estimated to recover $76,590,510 in supplier non-gas costs (EGU Exhibit 1.05, page 2, line 6). Enbridge Gas has provided a calculation of the SNG rates at EGU Exhibit 1.05 page 3. The GS and FS Summer/Winter differentials are also shown on pages 4 and 5 of EGU Exhibit 1.05.

b. Supplier Non-Gas Amortization. Consistent with the Division of Public Utilities' recommendation in Docket No. 11-057-08, the Company began amortizing the balance in the SNG portion of the 191 account annually instead of semi-annually. The change was meant to reduce volatility and interest costs by limiting the swings in the SNG account due to the changes in the definitions of commodity and SNG costs determined in Docket No. 19-057-T01. The Company now estimates that the SNG balance should swing between $14,000,000 over-collected and $14,000,000 under-collected. Therefore, the Company is proposing to continue amortizing the $14,775,163 over-collected portion of this balance established in the previous pass-through case, Docket No. 24-0574-09, using the forecasted volumes in this docket. The credit amortizations are shown on EGU Exhibit 1.05 page 3, lines 17-19.

c. In Docket No. 14-057-31, the Commission approved the Company's request to charge transportation customers for SNG costs associated with the services they use. The Company began charging these customers a "Transportation Imbalance Charge" in February 2016 and began collecting from customers in March 2016. A total of $302,489 was collected from transportation customers from May to August 2024 and included in the SNG balance used to calculate the credit amortizations. The Company is submitting an application concurrently with this Application to review and update the Transportation Imbalance Charge based on the most recent 12 months of data. See Docket No. 24-057-17 for more information.

21. Change in Typical Customer's Bill. The annualized consolidated change in rates calculated in this Application is a 3.45% decrease, or a decrease of $22.82 per year for a typical GS residential customer using 70 dekatherms per year. The projected month-by-month changes in rates are shown in EGU Exhibit 1.06.

22. Proposed Tariff Sheets. Enbridge Gas' proposed Utah Tariff sheets reflect the commodity costs, and of the changes in supplier non-gas costs allocable to Utah customers (EGU Exhibit 1.07 and 1.08).

23. Combined Tariff Sheets. In addition to this Pass-Through Application, the Company is also concurrently filing an Application for an adjustment to the Daily Transportation Imbalance Charge in Docket No. 24-057-17, an Application to adjust the Energy Efficiency rate in Docket No. 24-057-18, an Application to adjust the Conservation Enabling Tariff in Docket No. 24-057-19, an Application to adjust Low Income/Energy Assistance rate in Docket No. 24-057-20, and an Application to change the Infrastructure Rate Adjustment in Docket No. 24-057-21. EGU Exhibit 1.09 and 1.10 shows the proposed rate schedules that reflect the Tariff sheets that will be effective should the Commission approve all applications.

24. Effect on Earnings. Because the rate sought in this Application is a pass through of the direct costs of gas that Enbridge Gas obtains for its customers, there will be no change in the Company's rate of return. Net profits are also unaffected except for the return on the changed amount of working storage gas which was approved by the Commission in Docket No. 22-057-03.

25. Exhibits. Enbridge Gas submits the following Enbridge Gas Exhibits in support of its request for an adjustment in its rates for natural gas service in Utah:

EGU Exhibit 1.01 Summary of Pass-Through Costs

EGU Exhibit 1.02 Test-Year Commodity Costs

EGU Confidential Exhibit 1.03 Comparison of Natural Gas Price Forecasts

EGU Exhibit 1.04 Test-Year SNG Costs

EGU Exhibit 1.05 Calculation of Commodity and SNG Rates

EGU Exhibit 1.06 Effect on GS Typical Customer

EGU Exhibit 1.07 Legislative Tariff Sheets

EGU Exhibit 1.08 Proposed Tariff Sheets

EGU Exhibit 1.09 Combined Legislative Tariff Sheets

EGU Exhibit 1.10 Combined Proposed Tariff Sheets

EGU Exhibit 1.11 Pass Through Model

WHEREFORE, Enbridge Gas respectfully requests that the Commission, in accordance with its authority, rules and procedures and the Company's Tariff:

1. Enter an order authorizing Enbridge Gas to implement a decrease in rates and charges applicable to its Utah natural gas service that reflect annualized gas costs of $608,417,569 as adjusted in EGU Exhibit 1.05 and as more fully set out in this Application and in EGU Exhibit 1.07 and 1.08.

2. Authorize Enbridge Gas to implement the revised rates effective November 1, 2024 on an interim basis.

DATED the 1st day of October 2024.

Respectfully submitted,

ENBRIDGE GAS UTAH

Jenniffer Nelson Clark

Jenniffer Nelson Clark
Attorney for Enbridge Gas Utah

VERIFICATION

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

Kelly Mendenhall, being first duly sworn upon oath, deposes and states: he is the Director, Regulatory and Pricing of Enbridge Gas Utah; he has direct personal knowledge of the matters addressed herein; he has read the foregoing Application; and the statements made in the Application are true and correct to the best of his knowledge, information and belief. The documents attached thereto are true and correct copies of the documents they purport to be.

Kelly Mendenhall
Director, Regulatory and Pricing

Subscribed and sworn to before me this 1 day of October 2024.

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

CERTIFICATE OF SERVICE

This is to certify that a true and correct copy of the Verified Application was served upon the following persons by e-mail on October 1, 2024:

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