NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2023-2024
COST OF GAS FILING

PREFILED TESTIMONY OF
<u>FRANCIS X. WELLS</u>

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. What is your relationship with Northern Utilities, Inc.?

A. I am employed by Unitil Service Corp. (the "Service Company") as Manager of Energy Planning. The Service Company provides professional services to Northern Utilities, Inc.

Q. Please briefly describe your educational and business experience.

A. I earned my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined the Service Company in September 1996 and have worked primarily in the Energy Contracts department. My primary responsibilities involve gas supply planning and acquisition.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I have testified as Northern's gas supply witness before the Commission in Northern's Cost of Gas ("COG") proceedings.

Q. Please summarize your prepared direct testimony in this proceeding.

A. The purpose of my testimony is to present and support Northern's gas supply cost forecast, which was used for the calculation of the proposed COG.

The 2023-2024 fixed, annual demand cost estimates are 10% lower than the fixed, annual demand cost estimates provided for the prior 2022-2023 Winter Period CGF filing. The major reasons for this decrease are lower peaking supply demand costs and higher asset management agreement revenue, partially offset by higher pipeline transportation charges due mostly to the addition of new capacity to Northern's portfolio, effective April 1, 2024.

This capacity was acquired via open seasons on TransCanada and PNGTS pipelines and will be discussed in more detail later in my testimony. The cost of this new capacity has been included in this Annual Period 2023-2024 COG Filing. However, Northern plans to separately file a request for approval by the Commission of this long-term capacity commitment.

Estimated average delivered commodity rates for the 2023-2024 Winter Period are 41% lower than the average delivered commodity rates estimated for the 2022-2023 Winter Period COG. The major reason for this increase is lower NYMEX supply costs, partially offset by higher delivered peaking supply costs. Estimated average delivery commodity rates for the 2024 Summer Period are 50% lower than the average delivered commodity rates estimated for the 2023 Summer Period COG. Lower NYMEX supply costs are the major reason for this decrease.

Northern projects combined sales service and delivery service distribution deliveries to be 8,519,593 Dth in the New Hampshire Division for the 2023-2024 Annual Period, which is 3.1% higher than the 2022-2023 Annual Period weather-normalized distribution deliveries and 3.4% higher than the 2021-2022 Annual Period weather-normalized distribution deliveries. Of the 8,519,593 Dth of projected distribution system deliveries, Northern projects that 4,004,657 Dth will be supplied by the Company through Sales Service. In order to supply 4,004,657 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,033,701 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 131,139 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,164,840 Dth for the upcoming year. The details behind these estimates are contained in Attachments NUI-FXW-1 and -2.

Northern's portfolio has 142,844 Dth maximum daily quantity of Pipeline, Storage and Peaking Capacity (each of these Capacity terms as defined in the Company's New Hampshire Division Delivery Service Terms and Conditions). I review the portfolio in more detail in the body of my testimony. Details of this portfolio are provided in Attachment NUI-FXW-4. I review the portfolio in more detail in the body of my testimony, including updates to the portfolio that have occurred since the 2022-2023 Annual Period COG Filing as well as an update on Northern's implementation of its Price Risk Mitigation Plan.

I project Northern's total company (including both the Maine and New Hampshire Divisions) demand cost for the November 2023 through October 2024 gas year to be $37,271,543. (*See* Attachment NUI-FXW-5). Mr. Chris Kahl, who is also testifying in this proceeding, presents the allocation of the total annual demand cost to Northern's New Hampshire Division and the portion of that allocation of annual demand costs between the Winter and Summer COG recoveries. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $6,228,246. (*See* Attachment NUI-FXW-6). I also discuss the updated Capacity Allocators and Capacity Ratio pursuant to the New Hampshire Division capacity assignment program, which are provided as Attachment NUI-FXW-7.

I project that Northern's total company (including both the Maine and New Hampshire Divisions) commodity cost to provide sales service during the 2023-2024 Winter Period will be $47,125,083 at an average rate equal to $5.159 per Dth. (*See* Attachment NUI-FXW-8). 2024 Summer Period commodity cost to provide sales service are projected to be $6,088,689 at an average rate equal to $2.490 per Dth.

Finally, I provide the proposed Re-entry Rate, applicable to Capacity Assigned Delivery Service customers who switch to Northern's Sales Service, and the proposed Conversion Rates, applicable to Capacity Exempt Delivery Service customers who switch to Northern's Sales Service. I also provide the supporting calculations for these proposed rates. These calculations are provided in Attachment NUI-FXW-11.

II. SALES AND SENDOUT FORECAST

Q. Please describe the Company's forecasts sales.

A. The sales forecast for the residential, regular general, and large rate classes are developed by independently forecasting meter growth and usage per meter. The forecasted usage per meter assumes 'normal' weather which is the average of the actual degree days over the last 15 years. In addition, Business Development personnel are consulted for comments on significant usage changes for the Company's large customers which, when necessary, are included in the sales forecast. The forecast seeks to limit subjectivity and typically relies on historical trends, while the regression utilizes econometric or demographic variables when possible.

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. I have prepared Table 1, below, which provides a summary of the company's forecast of total billed distribution deliveries (Dth) for the upcoming 2023-2024 Annual Period.

Table 1. 2023-2024 Annual New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years

Month	2023-2024 Forecast	2022-2023 Weather-Normalized Actual	2023-2024 minus 2022-2023	Percent Change	2021-2022 Weather-Normalized Actual	2023-2024 minus 2021-2022	Percent Change
Nov	653,194	626,546	26,648	4.3%	635,156	18,037	2.8%
Dec	980,617	912,920	67,697	7.4%	913,062	67,555	7.4%
Jan	1,235,746	1,199,299	36,446	3.0%	1,199,657	36,089	3.0%
Feb	1,230,569	1,179,694	50,875	4.3%	1,187,575	42,994	3.6%
Mar	1,089,940	1,061,045	28,896	2.7%	1,073,134	16,807	1.6%
Apr	805,992	775,012	30,980	4.0%	760,014	45,977	6.0%
May	568,006	552,584	15,422	2.8%	545,040	22,966	4.2%
Jun	405,488	405,800	-312	-0.1%	395,165	10,323	2.6%
Jul	363,497	364,133	-636	-0.2%	344,188	19,309	5.6%
Aug	363,059	363,658	-599	-0.2%	360,910	2,149	0.6%
Sep	378,071	378,705	-633	-0.2%	378,022	50	0.0%
Oct	445,414	445,802	-388	-0.1%	449,022	-3,608	-0.8%
Winter	5,996,057	5,754,516	241,542	4.2%	5,768,598	227,459	3.9%
Summer	2,523,535	2,510,682	12,853	0.5%	2,472,347	51,188	2.1%
Annual	8,519,593	8,265,197	254,395	3.1%	8,240,945	278,647	3.4%

Forecast distribution deliveries are projected to increase 3.1% compared to the 2022-2023 weather-normalized actual sales. Page 1 of Attachment NUI-FXW-1 shows that the increase in sales is explained by a 3.4% projected increase in meter counts and a 1.0% increase in projected average use per meter.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2023-2024 Annual Period in Attachment NUI-FXW-1. Page 1 of Attachment NUI-FXW-1 provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2023-2024 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2022-2023 and 2021-2022 Annual Periods. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment NUI-FXW-1 provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. How does the Company allocate total distribution deliveries between Sales Service and Delivery Service deliveries?

A. For each rate class, the Company calculated the percentage of total distribution deliveries that were attributable to Sales Service for the 12-month period May 2022 through April 2023. These percentages were used to estimate the percentage of billed sales that would be supplied by the Company under Sales Service. Delivery Service sales were allocated between Capacity Assigned and Capacity Exempt based on monthly percentage of weather-normalized deliveries by rate class over the same 12-month period.

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. I have prepared Table 2, below, which provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries, Company Managed Deliveries and City-Gate Receipts[1] for the upcoming Winter Period.

[1] When I use the term "City-Gate Receipts", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary

Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Company Managed Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-23	849,755	432,947	24,450	460,537
Dec-23	1,086,379	633,307	26,159	664,059
Jan-24	1,234,028	737,366	31,248	773,962
Feb-24	1,103,757	640,550	24,172	669,368
Mar-24	1,001,592	544,062	25,110	573,117
Apr-24	720,546	310,993	0	313,248
May-24	467,590	152,103	0	153,206
Jun-24	387,909	98,430	0	99,144
Jul-24	378,656	84,103	0	84,713
Aug-24	381,579	85,031	0	85,648
Sep-24	394,795	94,863	0	95,551
Oct-24	513,006	190,903	0	192,287
Winter	5,996,057	3,299,225	131,139	3,454,291
Summer	2,523,535	705,432	0	710,549
Annual	8,519,593	4,004,657	131,139	4,164,840

The detailed calculations can be found in Attachment NUI-FXW-2. On Pages 1 and 2 of Attachment NUI-FXW-2, I present calendar month and billed sales service deliveries by rate class. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire Division. An annual summary of the impact of migration by rate class can be found in Attachment NUI-FXW-19.

On Page 3 of Attachment NUI-FXW-2, I present my calculations of the city-gate receipts. First, I estimated Company Gas Allowance by multiplying the forecast Sales Service Deliveries and the Company Gas Allowance percentage. Company Gas Allowance includes both Company Use and Lost and Unaccounted For. The Company Gas Allowance Percentage was based on the recent history of actual data, which are presented in Attachment NUI-FXW-3. Finally, I added Northern's projection of Company Managed Sales pursuant to the New Hampshire Division's capacity assignment program.

Q. What are Company Managed Sales?

A. Company Managed Sales are a form of Capacity Assignment. Capacity Assignment is a means of transferring the demand cost responsibility for capacity contracts from Northern to the retail marketers on its system. Whenever a retail marketer enrolls a customer, who is "capacity assigned," the retail marketer assumes cost and benefits of a pro-rated portion of the capacity contracts entered into by Northern, subject to the capacity assignment provisions of each division. These capacity contracts can include interstate pipeline contracts, underground storage contracts and on-site peaking facilities. Such transfer may be achieved by releasing capacity directly to the retail marketer ("Capacity Release"), who may then purchase their own supplies and utilize the released contracts to deliver supplies to their customers. Pursuant to Northern's Delivery Service Terms and Conditions for its New Hampshire Division, all upstream pipeline and underground storage capacity that delivers to Northern's system is assigned via Capacity Release except for upstream pipeline and storage capacity resources that require the Bay State Exchange Agreement. These excepted pipeline and storage resources are assigned via Company Managed Supply. On-system peaking capacity, such as Northern's Lewiston LNG plant, is also assigned via Company Managed Supply. Under the Company Managed Supply form of capacity assignment, Northern bills the retail marketer for a pro-rated portion of these capacity resources at their respective actual costs and offers a city-gate delivered supply service. Such city-gate supplies are priced in accordance with the capacity assignment provisions of each division. Such arrangements are known as "Company Managed Sales."

Q. Please explain the process used to project Company Managed Sales.

A. Company Managed resources for the New Hampshire Division include pipeline (specifically Iroquois Receipts and Algonquin Receipts capacity paths) and on-system peaking resources (Lewiston LNG plant). The maximum daily volume of each Company managed resource was estimated based on the allocations presented in Attachment NUI-FXW-6. Northern allows marketers to nominate their peaking Company managed resources on a daily basis. In addition, marketers are required to purchase pipeline baseload supplies that are associated with the Company Managed pipeline resources. The Company Managed Sales forecast assumes that marketers will utilize all Pipeline and Peaking Company-managed supply available to them under the capacity assignment program.

III. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its Sales Service customers and meet Company Managed Supply obligations.

A. I have prepared Table 3, below, which provides an overview of the sources of supply available to Northern through its portfolio of contracts, including transportation contracts, storage contracts, baseload and peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table 3. Northern Capacity Summary (Dth/Day)

Pipeline Capacity Paths	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	30,621
Storage Capacity Paths	
Tennessee Firm Storage	2,644
Dawn Hub Storage	59,793
Total Storage Capacity	62,437
Peaking Capacity Paths	
LNG - On-System	6,500
Peaking Contract 1	29,895
Peaking Contract 2	9,965
Additional Granite Capacity	3,426
Total Peaking Capacity	49,786
Total Design Day Capacity	142,844
Empress Capacity Effective April 1, 2024	12,456

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2023-2024 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above.

Table 3 can also be found on page 1 of Attachment NUI-FXW-4. Subsequent pages of Attachment NUI-FXW-4 include capacity path diagrams and capacity path details for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Capacity listed for each source of supply.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Maritimes & Northeast Pipelines, L.L.C. ("MNUS" or "Maritimes"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited

(“TransCanada”), Enbridge Gas, Inc. (“Enbridge” or “Union”)[2], Algonquin Gas Transmission Company (“Algonquin”), Iroquois Gas Transmission System, L.P. (“Iroquois”) and Texas Eastern Transmission System, L.P. (“Texas Eastern” or “TETCO”). The gas supply portfolio also includes long-term storage contracts with Enbridge and Tennessee. Northern’s gas supply portfolio for 2023-2024 includes two single-year peaking contracts, Peaking Contract 1 and Peaking Contract 2. Each contract was procured via an RFP process that concluded in May 2023. Northern also owns and operates a Liquefied Natural Gas (“LNG”) facility in Lewiston, ME, which Northern relies on to produce 6,500 Dth per day with a storage capacity of approximately 12,000 Dth of LNG. Also through an RFP Northern has procured an LNG Contract for up to 3,000 Dth per day with an annual contract quantity of up to 75,000 Dth beginning November 2023 and ending May 2024 in order to supply this facility. The gas supply portfolio includes an exchange agreement with Bay State Gas Company (“BSG Exchange” or “Bay State Exchange Agreement”), which is needed to bring the Iroquois Receipts, Leidy Hub Supply and Transco Zone 6, non-NY capacity path supplies into Northern’s system, as the delivery points on these capacity paths are on the Bay State Gas Company system.

The capacity path diagrams and capacity path details in Attachment NUI-FXW-4 show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, to move natural gas supplies from the sources of supply listed in Table 3 to Northern’s distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path

[2] Enbridge Gas, Inc. was formed on January 1, 2019 with the amalgamation of Enbridge Gas Distribution and Union Gas Limited.

diagrams show how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Q. Please describe the Company's process for procuring its gas supply commodity supplies.

A. Northern's practice is to secure most of its gas supply and asset management services through an annual RFP for terms beginning April 1 and running through March 31 each year. In March Northern completed its annual RFP for the delivery period of April 1, 2023 through March 31, 2024. Northern has entered into asset management agreements for the Atlantic Bridge Ramapo, Iroquois Receipts, Algonquin Receipts, Niagara, Tennessee Zone 0/L, PXP Dawn Hub, WXP Dawn Hub and Dawn Hub Storage capacity paths. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for LNG supplies for the upcoming winter.

Q. Please describe any changes in Northern's portfolio for the upcoming 2023-2024 Annual Period compared to the portfolio relied upon for the 2022-2023 Annual Period.

A. The following changes have been made to Northern's portfolio for the 2023-2024 Annual Period.

1. The Empress Capacity Path is expected to commence April 1, 2024. The contract term for the TCPL and PNGTS contracts of the Empress Capacity Path

are 30 years. This will provide Northern with an additional 12,456 Dth of capacity from its system back to Empress, Alberta, accessing Western Canadian Sedimentary Basin ("WCSB") supplies. Northern plans to separately file a request for approval from the Commission for this capacity.

2. Both Peaking Contract 1 and Peaking Contract 2 are short-term off-system peaking supply contacts that have been added to the portfolio this year. Peaking Contract 1 provides up to 30,000 Dth per Day and 600,000 Dth from November 2023 through March 2024. Peaking Contract 1 requires that Northern utilize all 600,000 Dth. Peaking Contract 2 provides up to 10,000 Dth per Day and up to 50,000 Dth from November through March 2024.
3. Effective April 1, 2023, Northern increased the maximum storage balance of its Enbridge Dawn Storage from 4,000,000 Dth to 6,000,000 Dth. The new storage contract (Contract No. LST155) has a five-year term. PXP Dawn Hub and WXP Dawn Hub Capacity Paths are now included as part of the Dawn Hub Storage Capacity Path.
4. Consistent with Northern's Price Risk Mitigation Plan, Northern has a target ratio of 75 percent of its November through March projected sendout requirements protected from volatility in NYMEX pricing. Due to higher fixed price peaking volumes (discussed in 2 above) and higher storage volumes (discussed in 3 above), lower volumes of fixed pipeline supplies are required to meet the target ratio. As of the initial filing in this proceeding, Northern has completed three of four fixed price blocks. The final fixed price blocks will be completed prior to the end of September.

Q. Please explain why Northern has secured the new Empress Capacity.

A. The purchase of this Empress Capacity is intended to reduce Northern's reliance on imported LNG. Generally, Northern is concerned with the current and future availability and pricing of imported LNG into New England. When New England natural gas demand exceeds the capacity of the pipeline system connecting New England to North American supplies, supply must be supplemented by imported LNG to meet all demand. New England as a whole, including Northern, is reliant upon imported LNG to reliably meet demand for natural gas during periods of cold weather. Therefore, peaking supply contracts (including those in Northern's portfolio) are sourced on imported LNG. In spite of their respective importance to the region for energy supply reliability, the operators of the major LNG importers into the New England energy market have uncertain futures. The Everett Marine Terminal, which is owned and operated by Constellation, is in the final year of a cost of service agreement with ISO New England. At the FERC 2023 New England Winter Gas-Electric Forum on June 20, 2023, Constellation warned that it was still looking for "sufficient bilateral contract support for the facility."[3] The Saint John LNG facility is owned and operated by Repsol. At the same forum, Repsol indicated that any "out of market solution favoring Everett" would ultimately "threaten the participation of existing electric and natural gas assets in those markets."[4]

Northern plans to file a more complete explanation of this purchase in its request for approval of the Empress Capacity.

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[3] 2023 New England Winter Gas-Electric Forum Transcript, Page 38, lines 18 and 19.
[4] 2023 New England Winter Gas-Electric Forum Transcript, Page 38, lines 18 through 25.

IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Kahl to calculate the 2023-2024 Winter and 2024 Summer COG rates.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2023 through October 2024, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities
- New Hampshire Division Capacity Assignment program demand revenues
- Northern's commodity costs

The allocation of Northern's supply costs to the New Hampshire Division was performed by Mr. Kahl. The figures I present in my testimony relate to total company costs, inclusive of both the Maine and New Hampshire Divisions.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 4, below, titled, "Estimated Gas Supply Demand Costs."

Table 4. Estimated Gas Supply Demand Costs
November 1, 2023 through October 31, 2024

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 18,101,384	Att NUI-FXW-5, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 32,519,306	Att NUI-FXW-5, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 5,098,273	Att NUI-FXW-5, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 3,492,781	Att NUI-FXW-5, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 4,034,000	Att NUI-FXW-5, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (25,974,200)	Att NUI-FXW-5, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 37,271,543	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Attachment NUI-FXW-5. Page 1 of Attachment NUI-FXW-5 provides the summary data presented here in Table 4. On page 2 of Attachment NUI-FXW-5, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Attachment NUI-FXW-5, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 4 and 5 of Attachment NUI-FXW-5 provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Attachment NUI-FXW-5, I forecast the capacity release and asset management revenue the Company expects to receive. Support for the transportation, storage and supply demand rates used in Attachment NUI-FXW-5 are found in the Attachment NUI-FXW-10, Supplier Prices.

Q. How does the 2023-2024 Winter COG forecasted annual demand cost compare with the 2022-2023 Winter COG forecasted annual demand cost?

A. 2022-2023 Winter CGF forecasted annual demand costs were equal to $41,345,857. 2023-2024 Winter CGF forecasted annual demand costs are equal to $37,271,543, reflecting a decrease in forecasted annual demand costs equal to $4,074,314 or 10%.

This majority of the change in projected demand cost is explained by the following.

1. <u>Increase in projected Asset Management Agreement revenue by $5,039,600.</u> Higher AMA revenue reflects the results of Northern's annual request-for-proposals process, reflecting higher overall value obtained through asset management agreements.
2. <u>Decrease in projected Peaking Supply Demand Costs by $7,394,417.</u> A multi-year peaking contract, which expired after last winter, was priced with demand and commodity components. There is no demand component in the pricing for the largest of the current Peaking Contracts, resulting in a significant decrease in demand costs and a corresponding increase in commodity costs.

3. <u>These decreases in demand costs are partially offset by increases in Pipeline and Storage costs equal to $8,359,703.</u> Pipeline capacity contract cost estimates increased $7,468,036 due mostly to the addition of Empress capacity contracts and an anticipated increase in Granite demand rates. Higher Storage capacity contract cost estimates increased $891,667 due to a full year of the higher Enbridge Dawn Hub storage volumes and demand rates in the new storage contract that began on April 1, 2023.

Q. Please provide Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of the demand revenues from capacity assignment in Attachment NUI-FXW-6. On page 1 of Attachment NUI-FXW-6, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Attachment NUI-FXW-6, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Attachment NUI-FXW-6. The 2023-2024 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $6,228,246.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2023 through April 2024?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 6 of Attachment NUI-FXW-6. The proposed Peaking Service Demand Charge is equal to $94.46 per Dth, as shown in Attachment NUI-FXW-6 and presented in the proposed revised Appendix A to the Delivery Service Terms and Conditions. Please note that the Peaking Service Demand Charge applies only to capacity assignment pertaining to the on-system LNG plant.

Q. Please provide the Capacity Allocation Factors to be used for Capacity Assignment under the current New Hampshire Division Delivery Service tariff for effect November 1, 2023.

A. The Capacity Allocation Factors are provided in the proposed tariff sheet, Appendix C to the New Hampshire Division's Delivery Service Terms and Conditions. My calculations are provided in Attachment NUI-FXW-7. These Capacity Allocation Factors reflect a Capacity Ratio equal to 0.985, which is equal to Total Design Day Capacity of 142,844 Dth divided by the Total Design Day Planning Load (inclusive of both Maine and New Hampshire) of 144,953 Dth.

Q. Please describe Northern's process for forecasting commodity costs.

A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts for sales service customers, which I calculated in Attachment NUI-FXW-2, and the supply sources available to Northern, which I presented in Attachment NUI-FXW-4. I forecast supply prices at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. To the extent that Northern's supply contract for a particular supply source provides for a fixed adder to the NYMEX Last Day Settlement, the contract prices are used to forecast the adder. If Northern's supply contract for a particular supply source does not provide for a fixed adder to the NYMEX Last Day Settlement, an estimate of the adder is based on the basis futures prices, through the Intercontinental Exchange ("ICE"). I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. Then, I utilized the

PLEXOS® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.[5]

As discussed previously, Northern has completed NYMEX price locks on 4 monthly blocks to achieve a target ratio of hedged NYMEX supplies to total supplies of 75 percent (the "Target Ratio"). The effect of these price locks were accounted for after the PLEXOS® model run was completed.

Q. Please present the Company's commodity cost forecast for the 2021-2022 Annual Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter and Summer Period in Tables 5 and 6, respectively.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes
November 2023 through April 2024

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Base Pipeline Resources	$ 19,950,169	4,922,393	$ 4.053
Storage Resources	$ 9,390,022	3,617,047	$ 2.596
Peaking Resources	$ 17,784,892	595,751	$ 29.853
Total Commodity Costs	$ 47,125,083	9,135,191	$ 5.159

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2024 through October 2024

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Base Pipeline Resources	$ 5,941,862	2,433,916	$ 2.441
Storage Resources	$ -	-	
Peaking Resources	$ 146,827	11,040	$ 13.300
Total Commodity Costs	$ 6,088,689	2,444,956	$ 2.490

[5] PLEXOS is an energy optimization software package, which was developed by Energy Exemplar.

In summary, Winter Period net projected delivered commodity costs equal approximately $47.1 million at an average delivered rate of $5.159 per Dth, and Summer Period net projected delivered commodity costs equal approximately $6.1 million at an average delivered rate of $2.490 per Dth. In support of this forecast, I prepared Attachment NUI-FXW-8 to show the monthly forecasted commodity cost by supply option. Page 1 of Attachment NUI-FXW-8 provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Attachment NUI-FXW-8 provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources. Attachment NUI-FXW-12 provides a seasonal summary of each supply source for Winter and Summer Periods, ranked by average delivered commodity cost.

The detailed calculations of the delivered commodity cost are found in Attachment NUI-FXW-9. For each supply source, I have provided the detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by Northern to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support of the supply prices and variable transportation charges found in Attachment NUI-FXW-9 are found in the Attachment NUI-FXW-10, Supplier Prices.

Q. How do forecasted commodity costs for the 2023-2024 Winter Period (November through April) compare with the forecasted commodity costs presented for the 2022-2023 Winter Period COG?

A. As show in Table 5, above, the 2021-2022 Winter Period COG forecasted commodity costs are equal to $47,125,083 at an average delivered rate of $5.159 per Dth. The 2022-2023 Winter Period COG forecasted commodity costs were equal to $84,546,814 an average delivered rate of $8.772 per Dth. Overall, 2023-2024 forecasted Winter Period commodity costs are 44% lower than 2022-2023 forecasted Winter Period costs due primarily to a 41% decrease in projected average unit cost. The 2023-2024 projected delivered volume is 5% lower than was projected in 2022-2023. Projected NYMEX prices are 54% lower at the time of this 2023-2024 Annual Period COG filing (averaging $3.36 per Dth), compared to projected NYMEX prices at the time of last year's 2022-2023 Annual Period COG filing (averaging $7.32 per Dth). The Company's unit cost forecast reflects these lower NYMEX prices. The projected average unit cost also reflects an increase in peaking supply commodity costs due to higher volumes due to the must-take provision of Peaking Contract 1.

Q. Please provide a summary of Northern's Price Risk Mitigation Plan.

A. Figure 1, below, provides a summary of Northern's Price Risk Mitigation Plan, which has been in effect since the 2022-2023 Winter Period.

Figure 1. Summary of Price Risk Mitigation Plan

Goals and Objectives:	Northern's objective is to mitigate the risk of significant mid-Winter Period Cost of Gas increases and to provide improved price certainty for customers during the Winter Season when usage is highest, while maintaining a high level of portfolio flexibility to respond to changes in demand due to weather, retail choice and other factors.
Target Ratio:	Northern plans to hedge 75 percent ("Target Ratio") of November through March projected volumes against increases in NYMEX prices. The Target Volume will be determined by multiplying Northern's projected sales service volumes times the Target Ratio.
Contracting Process:	Northern plans to utilize physical gas purchases to implement NYMEX hedges, in the form of underground storage and physical gas purchases under which the NYMEX portion of the price is fixed in advance of the Winter Season The volume of physical gas purchases with fixed NYMEX pricing will be determined by subtracting underground storage deliverability from the Target Volume.

Timing:	Northern plans no changes to its current underground storage injection practices[6]. NYMEX price locks under the Plan for baseload pipeline supplies would be implemented in 4 monthly blocks during June through September.
New England Spot Price Exposure:	Northern will limit exposure to daily New England spot prices, including the Algonquin city-gates and Tennessee Zone 6 daily index prices.

Q. Please provide a summary of Northern's projected hedge ratio relative to the Target Ratio in Northern's Price Risk Mitigation Plan.

A. Northern's projected supply volume for November 2023 through March 2024 is 8,164,760 Dth. Available supplies that will not be subject to NYMEX fluctuations during this period total 6,382,363 Dth, which is 78%, slightly higher than the 75% Target Ratio. Fixed supplies are comprised of 4,822,363 Dth of available underground storage fixed price supplies, 910,000 Dth of NYMEX hedged baseload supplies and 650,000 Dth (Peaking Contracts 1 and 2) of fixed peaking supplies. Of the 910,000 Dth of NYMEX hedged baseload supplies, 682,500 Dth are currently locked. The difference is the final block, which Northern intends to lock during the months of September in accordance with its Price Risk Mitigation Plan.

Q. Please summarize the NYMEX price locks executed under the Price Risk Mitigation Plan for the 2023-2024 Winter Period to date.

A. Table 7, below, summarizes the price locks that have been entered to date. These prices will not change, regardless of the movement in NYMEX pricing. The goal and

[6] Enbridge Dawn storage injection occurs April through September. Tennessee FS-MA storage injection occurs April through October.

objectives of the Price Risk Mitigation Plan are to provide greater cost certainty while maintaining flexibility needed to meet customer demands in a reliable fashion.

Table 7. NYMEX Price Locks

Item	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24
Block 1 Nov-Mar NYMEX Lock Volume	-	-	-	-	-
Block 1 Nov-Mar NYMEX Lock Price					
Block 1 Nov-Mar NYMEX Lock Cost	$ -	$ -	$ -	$ -	$ -
Block 1 Dec-Feb NYMEX Lock Volume		77,500	77,500	72,500	
Block 1 Dec-Feb NYMEX Lock Price		$ 3.675	$ 3.675	$ 3.675	
Block 1 Dec-Feb NYMEX Lock Cost		$ 284,813	$ 284,813	$ 266,438	
Block 2 Nov-Mar NYMEX Lock Volume	-	-	-	-	-
Block 2 Nov-Mar NYMEX Lock Price					
Block 2 Nov-Mar NYMEX Lock Cost	$ -	$ -	$ -	$ -	$ -
Block 2 Dec-Feb NYMEX Lock Volume		77,500	77,500	72,500	
Block 2 Dec-Feb NYMEX Lock Price		$ 3.750	$ 3.750	$ 3.750	
Block 2 Dec-Feb NYMEX Lock Cost		$ 290,625	$ 290,625	$ 271,875	
Block 3 Nov-Mar NYMEX Lock Volume	-	-	-	-	-
Block 3 Nov-Mar NYMEX Lock Price					
Block 3 Nov-Mar NYMEX Lock Cost	$ -	$ -	$ -	$ -	$ -
Block 3 Dec-Feb NYMEX Lock Volume		77,500	77,500	72,500	
Block 3 Dec-Feb NYMEX Lock Price		$ 3.887	$ 3.887	$ 3.887	
Block 3 Dec-Feb NYMEX Lock Cost		$ 301,243	$ 301,243	$ 281,808	
Block 4 Nov-Mar NYMEX Lock Volume	-	-	-	-	-
Block 4 Nov-Mar NYMEX Lock Price					
Block 4 Nov-Mar NYMEX Lock Cost	$ -	$ -	$ -	$ -	$ -
Block 4 Dec-Feb NYMEX Lock Volume		-	-	-	
Block 4 Dec-Feb NYMEX Lock Price					
Block 4 Dec-Feb NYMEX Lock Cost		$ -	$ -	$ -	
Total NYMEX Lock Volume	-	232,500	232,500	217,500	-
Weighted Average NYMEX Lock Price	$ -	$ 3.771	$ 3.771	$ 3.771	$ -
Total NYMEX Lock Cost	$ -	$ 876,680	$ 876,680	$ 820,120	$ -
Current NYMEX	$ 2.991	$ 3.453	$ 3.706	$ 3.634	$ 3.328
Hedging Impact on Cost of Gas	$ -	$ 73,858	$ 15,035	$ 29,725	$ -

Since these fixed price NYMEX hedges are incorporated into Northern's physical supply contracts, these overall block purchases are allocated to individual contracts. Specifically, the Tennessee Long-Haul supply contract has been amended to reflect these NYMEX hedge prices. Details of the allocations can be seen in Attachment NUI-FXW-9 for these individual supplies.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2022 through October 2023.

A. Please refer to Attachment NUI-CAK-7. This attachment is based upon the Company's PLEXOS® analysis, which I provided to Mr. Kahl.

Q. How do forecasted commodity costs for the 2024 Summer Period (May through October) compare with the forecasted commodity costs presented for the 2023 Summer Period COG?

A. As show in Table 6, above, the 2024 Summer Period COG forecasted commodity costs are equal to $6,088,689 at an average delivered rate of $2.490 per Dth. The 2023 Summer Period COG forecasted commodity costs were equal to $13,507,267 at an average delivered rate of $4.940 per Dth. Overall, 2024 forecasted Summer Period commodity costs at the time of this 2023-2024 Annual Period COG Filing are 55% lower than 2023 forecasted Summer Period costs at the time of last year's 2022-2023 Annual Period COG Filing due to a 50% decrease in projected average unit cost and a 11% decrease in projected delivered volumes. Projected NYMEX prices are 39% lower for the 2024 Summer Period (averaging $3.25 per Dth), compared to projected NYMEX for the 2022 Summer Period (averaging $5.33 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices.

Q. Please provide a summary of capacity utilization by supply source projected for the upcoming year.

A. Please refer to Attachments NUI-FXW-13, -14, -15 and -16. Attachment NUI-FXW-13 provides monthly supply volumes for Northern's normal year weather scenario. The data in Attachment NUI-FXW-13 is also found in Attachment NUI-FXW-8. Attachment NUI-FXW-14 provides monthly supply volumes for Northern's design cold year weather scenario. Attachment NUI-FXW-15 calculates the capacity utilization of all supply resources under the normal weather scenario. Attachment NUI-FXW-16 calculates the capacity utilization of all supply resources under the design cold weather scenario.

Q. Please provide Northern's Design Day Report for the upcoming Winter Period.

A. Northern's Design Day Report is found in Attachment NUI-FXW-17.

Q. Please provide Northern's 7-Day Cold Snap Analysis for the upcoming Winter Period.

A. Northern's 7-Day Cold Snap Analysis is found in Attachment NUI-FXW-18.

V. PROPOSED RE-ENTRY AND CONVERSION SURCHARGES

Q. Please describe the Re-entry Surcharge and the Conversion Surcharge.

A. The Re-entry Surcharge is applicable to all Capacity Assigned Delivery Service customers who switch from a retail marketer to Northern's Sales Service, and the Conversion Surcharge is applicable to all Capacity Exempt Delivery Service customers who switch from a retail marketer to Northern's Sales Service. I have prepared proposed updated Re-entry and Conversion Surcharges to be effective for the 2023-2024 Winter Period. Customers electing to migrate and purchase their supply from Northern shall be required to continue purchasing Northern's Sales Service until April 30, 2024. After this time, such customers may elect to either switch to a retail marketer or continue purchasing Sales Service from Northern under the normal cost of gas rates.

Q. Please provide the proposed Re-entry Surcharge and the proposed Conversion Surcharge.

A. Proposed Appendix D to the Delivery Service Terms and Conditions, provides the Re-entry Surcharge and the Conversion Surcharge. The Re-entry Surcharge and

Conversion Surcharge will be applied as a surcharge in addition to the normal cost of gas rates. These surcharges shall only be applicable to customers switching from Delivery Service to Sales Service.

Q. Please provide your calculations for the Re-entry Surcharge and the Conversion Surcharges.

A. Please refer to Attachment NUI-FXW-11. Page 1 shows the Re-entry Surcharge and Conversion Surcharge calculations. The Re-entry surcharge reflects the removal of any prior period credits, such as an over-recovery due to incumbent Sales Service Customers. The Conversion Surcharge reflects the removal of prior period credits due to incumbent Sales Service customers plus the incremental cost to serve the customers, based on estimated incremental commodity prices. Conversion customers will have a floor price equal to the COG for Low Load Factor customers, removing prior period credits.

Page 2 is the Incremental Commodity Price Worksheet. Pages 3 through 9 are the Load Shape Price Factor Worksheet. Page 10 is the projected city-gate sendout forecast of Delivery Service loads that are not currently subject to Capacity Assignment.

Q. Does this conclude your testimony?

A. Yes it does.

TransCanada PipeLines Limited
Mainline Tolls - effective January 1, 2022 to December 31, 2026 (CER Order TG-014-2020)
Abandonment Surcharges - effective January 1, 2023 to December 31, 2023 (CER Order TG-008-2022)
Rate Riders - effective January 1, 2023 to December 31, 2023 (CER Order TG-007-2022)

Notes: (i) Aggregate charges for Mainline transportation service will include the applicable transportation toll, abandonment surcharge, delivery pressure toll (if applicable), rate rider (if applicable) and Dawn receipt surcharge (if applicable) pursuant to the Mainline Tariff.
(ii) Any transportation with a Union Dawn receipt point is subject to a Union Dawn Receipt Point Surcharge. Transport under FT, FT-NR, FT-SN and EMB service is subject to the monthly surcharge toll, and other transportation services are subject to the daily equivalent toll. Refer to page 2 for the Union Dawn Receipt Point Surcharge tolls.
(iii) Transportation with receipt points from delivery areas or Spruce is for STFT and IT service only.
(iv) The following delivery points are subject to an additional charge for delivery pressure: Emerson 1 & 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa, and East Hereford. Refer to page 2 for the delivery pressure toll.
(v) The following transportation services are subject to the Abandonment Surcharges: FT, FT-NR, STS, STS-L, FT-SN, MFP, EMB, Herbert LTFP, Dawn LTFP, NBJ LTFP, MDS, IT, STFT, and ST-SN. The Daily Equivalent Abandonment Surcharge is only applicable to IT, STFT, ST-SN, ARPs, Diversions, and STS Overrun.
vi) The following transportation services are subject to rate riders: FT, FT-NR, FT-SN, STS, STS-L, and EMB.

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/Month)	Daily Equivalent FT for IT / STFT ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)	Rate Rider ($/GJ/Month)	Daily Equivalent Rate Rider ($/GJ)
1	Empress	Empress	2.53979	0.0835	0.03042	0.0010	-0.47754	-0.0157
2	Empress	TransGas SSDA	6.12592	0.2014	0.47146	0.0155	-1.22883	-0.0404
3	Empress	Centram SSDA	8.70221	0.2861	0.78475	0.0258	-1.76721	-0.0581
4	Empress	Centram MDA	11.25417	0.3700	1.09804	0.0361	-2.30254	-0.0757
5	Empress	Centrat MDA	12.63813	0.4155	1.26838	0.0417	-2.59150	-0.0852
6	Empress	Union WDA	17.65079	0.5803	1.88279	0.0619	-3.64088	-0.1197
7	Empress	Nipigon WDA	19.22638	0.6321	2.07442	0.0682	-3.96938	-0.1305
8	Empress	Union NDA	27.32938	0.8985	3.06904	0.1009	-5.66663	-0.1863
9	Empress	Calstock NDA	22.56004	0.7417	2.48504	0.0817	-4.66896	-0.1535
10	Empress	Tunis NDA	25.18196	0.8279	2.80442	0.0922	-5.21646	-0.1715
11	Empress	Energir NDA	27.80083	0.9140	3.12683	0.1028	-5.76700	-0.1896
12	Empress	Union SSMDA	24.39417	0.8020	2.71013	0.0891	-5.05221	-0.1661
13	Empress	Union NCDA	34.87271	1.1465	3.43100	0.1128	-5.92213	-0.1947
14	Empress	Union CDA	36.30838	1.1937	3.52529	0.1159	-5.94038	-0.1953
15	Empress	Union ECDA	37.05967	1.2184	3.57092	0.1174	-5.94038	-0.1953
16	Empress	Union EDA	40.97733	1.3472	3.81121	0.1253	-5.92213	-0.1947
17	Empress	Union Parkway Belt	36.52433	1.2008	3.53746	0.1163	-5.94038	-0.1953
18	Empress	Enbridge CDA	37.69233	1.2392	3.61046	0.1187	-5.94038	-0.1953
19	Empress	Enbridge Parkway CDA	36.52433	1.2008	3.53746	0.1163	-5.94038	-0.1953
20	Empress	Enbridge EDA	39.27400	1.2912	3.70475	0.1218	-5.92213	-0.1947
21	Empress	KPUC EDA	42.26700	1.3896	3.89029	0.1279	-5.92213	-0.1947
22	Empress	Energir EDA	44.09200	1.4496	4.00588	0.1317	-5.92213	-0.1947
23	Empress	Enbridge SWDA	32.02875	1.0530	3.25763	0.1071	-5.94038	-0.1953
24	Empress	Union SWDA	31.98617	1.0516	3.25458	0.1070	-5.94038	-0.1953
25	Empress	Chippawa	38.02083	1.2500	3.63175	0.1194	-5.94038	-0.1953
26	Empress	Cornwall	40.67013	1.3371	3.79296	0.1247	-5.92213	-0.1947
27	Empress	East Hereford	47.72679	1.5691	4.23096	0.1391	-5.92213	-0.1947
28	Empress	Emerson 1	12.85104	0.4225	1.29575	0.0426	-2.63713	-0.0867
29	Empress	Emerson 2	12.85104	0.4225	1.29575	0.0426	-2.63713	-0.0867
30	Empress	Iroquois	40.01313	1.3155	3.75038	0.1233	-5.92213	-0.1947
31	Empress	Kirkwall	35.76696	1.1759	3.49183	0.1148	-5.94038	-0.1953
32	Empress	Napierville	43.71483	1.4372	3.98154	0.1309	-5.92213	-0.1947
33	Empress	Niagara Falls	37.97217	1.2484	3.62871	0.1193	-5.94038	-0.1953
34	Empress	North Bay Junction	28.55517	0.9388	3.21808	0.1058	-5.92213	-0.1947
35	Empress	Philipsburg	44.06158	1.4486	4.00283	0.1316	-5.92213	-0.1947
36	Empress	Spruce	12.63813	0.4155	1.26838	0.0417	-2.59150	-0.0852
37	Empress	St. Clair	28.63425	0.9414	3.23025	0.1062	-5.94038	-0.1953
38	Empress	Welwyn	8.70221	0.2861	0.78475	0.0258	-1.76721	-0.0581
39	Empress	Dawn Export	32.02875	1.0530	3.25763	0.1071	-5.94038	-0.1953
40	Bayhurst 1	Empress	2.84396	0.0935	0.06692	0.0022	-0.54142	-0.0178
41	Bayhurst 1	TransGas SSDA	5.81871	0.1913	0.43192	0.0142	-1.16496	-0.0383
42	Bayhurst 1	Centram SSDA	8.39804	0.2761	0.74825	0.0246	-1.70333	-0.0560
43	Bayhurst 1	Centram MDA	10.95000	0.3600	1.06154	0.0349	-2.23867	-0.0736
44	Bayhurst 1	Centrat MDA	12.33396	0.4055	1.23188	0.0405	-2.52763	-0.0831

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/Month)	Daily Equivalent FT for IT / STFT ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)	Rate Rider ($/GJ/Month)	Daily Equivalent Rate Rider ($/GJ)
1	Union NDA	Enbridge EDA	-	0.4769	-	0.0220	-	-0.0242
2	Union NDA	KPUC EDA	-	0.5748	-	0.0281	-	-0.0242
3	Union NDA	Energir EDA	-	0.6348	-	0.0318	-	-0.0242
4	Union NDA	Enbridge SWDA	-	0.6014	-	0.0298	-	-0.0242
5	Union NDA	Union SWDA	-	0.6029	-	0.0298	-	-0.0242
6	Union NDA	Chippawa	-	0.5417	-	0.0260	-	-0.0242
7	Union NDA	Cornwall	-	0.5224	-	0.0248	-	-0.0242
8	Union NDA	East Hereford	-	0.7544	-	0.0393	-	-0.0242
9	Union NDA	Emerson 1	-	0.6135	-	0.0660	-	-0.1267
10	Union NDA	Emerson 2	-	0.6135	-	0.0660	-	-0.1267
11	Union NDA	Iroquois	-	0.5008	-	0.0235	-	-0.0242
12	Union NDA	Kirkwall	-	0.4785	-	0.0221	-	-0.0242
13	Union NDA	Napierville	-	0.6225	-	0.0311	-	-0.0242
14	Union NDA	Niagara Falls	-	0.5401	-	0.0259	-	-0.0242
15	Union NDA	North Bay Junction	-	0.1241	-	0.0060	-	-0.0242
16	Union NDA	Philipsburg	-	0.6339	-	0.0318	-	-0.0242
17	Union NDA	Spruce	-	0.5665	-	0.0602	-	-0.1168
18	Union NDA	St. Clair	-	0.6170	-	0.0307	-	-0.0242
19	Union NDA	Welwyn	-	0.6959	-	0.0761	-	-0.1439
20	Union NDA	Dawn Export	-	0.6014	-	0.0298	-	-0.0242
21	Union Parkway Belt	Empress	36.52433	1.2008	3.53746	0.1163	-5.94038	-0.1953
22	Union Parkway Belt	TransGas SSDA	32.93821	1.0829	3.09946	0.1019	-5.18908	-0.1706
23	Union Parkway Belt	Centram SSDA	30.35888	0.9981	2.78313	0.0915	-4.65071	-0.1529
24	Union Parkway Belt	Centram MDA	27.81908	0.9146	2.47288	0.0813	-4.11842	-0.1354
25	Union Parkway Belt	Centrat MDA	28.49738	0.9369	2.42421	0.0797	-3.80817	-0.1252
26	Union Parkway Belt	Union WDA	23.89229	0.7855	1.86150	0.0612	-2.84700	-0.0936
27	Union Parkway Belt	Nipigon WDA	21.91217	0.7204	1.61817	0.0532	-2.43029	-0.0799
28	Union Parkway Belt	Union NDA	13.80004	0.4537	0.62354	0.0205	-0.73608	-0.0242
29	Union Parkway Belt	Calstock NDA	18.57850	0.6108	1.21058	0.0398	-1.73375	-0.0570
30	Union Parkway Belt	Tunis NDA	15.95354	0.5245	0.88817	0.0292	-1.18321	-0.0389
31	Union Parkway Belt	Energir NDA	13.73008	0.4514	0.61442	0.0202	-0.71783	-0.0236
32	Union Parkway Belt	Union SSMDA	16.31854	0.5365	1.06154	0.0349	-1.71246	-0.0563
33	Union Parkway Belt	Union NCDA	6.64604	0.2185	0.26158	0.0086	0.00000	0.0000
34	Union Parkway Belt	Union CDA	4.16100	0.1368	0.10950	0.0036	0.00000	0.0000
35	Union Parkway Belt	Union ECDA	3.47358	0.1142	0.06388	0.0021	0.00000	0.0000
36	Union Parkway Belt	Union EDA	9.02158	0.2966	0.41063	0.0135	0.00000	0.0000
37	Union Parkway Belt	Union Parkway Belt	2.92000	0.0960	0.03042	0.0010	0.00000	0.0000
38	Union Parkway Belt	Enbridge CDA	4.55946	0.1499	0.13383	0.0044	0.00000	0.0000
39	Union Parkway Belt	Enbridge Parkway CDA	2.92000	0.0960	0.03042	0.0010	0.00000	0.0000
40	Union Parkway Belt	Enbridge EDA	12.02067	0.3952	0.59921	0.0197	0.00000	0.0000
41	Union Parkway Belt	KPUC EDA	8.94250	0.2940	0.40758	0.0134	0.00000	0.0000
42	Union Parkway Belt	Energir EDA	15.63721	0.5141	0.82429	0.0271	0.00000	0.0000
43	Union Parkway Belt	Enbridge SWDA	7.41558	0.2438	0.31025	0.0102	0.00000	0.0000
44	Union Parkway Belt	Union SWDA	7.45817	0.2452	0.31329	0.0103	0.00000	0.0000
45	Union Parkway Belt	Chippawa	5.59667	0.1840	0.19771	0.0065	0.00000	0.0000
46	Union Parkway Belt	Cornwall	12.21838	0.4017	0.61138	0.0201	0.00000	0.0000
47	Union Parkway Belt	East Hereford	19.27504	0.6337	1.04938	0.0345	0.00000	0.0000
48	Union Parkway Belt	Emerson 1	26.21004	0.8617	2.27517	0.0748	-3.78079	-0.1243
49	Union Parkway Belt	Emerson 2	26.21004	0.8617	2.27517	0.0748	-3.78079	-0.1243
50	Union Parkway Belt	Iroquois	11.37888	0.3741	0.55663	0.0183	0.00000	0.0000
51	Union Parkway Belt	Kirkwall	3.67738	0.1209	0.07908	0.0026	0.00000	0.0000
52	Union Parkway Belt	Napierville	15.26004	0.5017	0.79996	0.0263	0.00000	0.0000
53	Union Parkway Belt	Niagara Falls	5.55104	0.1825	0.19467	0.0064	0.00000	0.0000
54	Union Parkway Belt	North Bay Junction	10.04358	0.3302	0.47450	0.0156	0.00000	0.0000
55	Union Parkway Belt	Philipsburg	15.60679	0.5131	0.82125	0.0270	0.00000	0.0000
56	Union Parkway Belt	Spruce	28.49738	0.9369	2.42421	0.0797	-3.80817	-0.1252
57	Union Parkway Belt	St. Clair	7.88704	0.2593	0.34067	0.0112	0.00000	0.0000
58	Union Parkway Belt	Welwyn	30.35888	0.9981	2.78313	0.0915	-4.65071	-0.1529
59	Union Parkway Belt	Dawn Export	7.41558	0.2438	0.31025	0.0102	0.00000	0.0000

Effective
2023-07-01
Rate M12
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ENBRIDGE GAS INC.
UNION SOUTH
TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

Applicable Points
Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).
Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Parkway facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically.
Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charges (applied to daily contract demand)	Fuel and Commodity Charges			
		Union Supplied Fuel	Shipper Supplied Fuel		
		Fuel and Commodity Charge	Fuel		Commodity Charge
	Rate/GJ	Rate/GJ	Ratio %	AND	Rate/GJ
Firm Transportation (1), (5)					
Dawn to Parkway	$3.760	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$3.190				
Kirkwall to Parkway	$0.570				
M12-X Firm Transportation					
Between Dawn, Kirkwall and Parkway	$4.648	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)					
Dawn to Parkway – Maximum	$9.024	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$9.024				
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.173%		
Carbon Charge (applied to all quantities transported)					
Facility Carbon Charge		$0.004			$0.004

BANK OF CANADA
BANQUE DU CANADA

Daily exchange rates: Lookup tool

Search and download exchange rate data.

All Bank of Canada exchange rates are indicative rates only, obtained from averages of aggregated price quotes from financial institutions. For details, please read our full **Terms and Conditions**.

US dollar (USD)

Date	USD → CAD	CAD → USD
2023-07-28	1.3232	0.7557

Month	Historic TCPL Fuel Rates Parkway to East Hereford	Empress to East Hereford
May-22	1.48%	5.40%
Jun-22	1.46%	5.41%
Jul-22	1.56%	5.76%
Aug-22	1.57%	5.73%
Sep-22	1.40%	5.56%
Oct-22	1.55%	5.62%
Nov-22	1.42%	4.77%
Dec-22	1.58%	4.90%
Jan-23	2.01%	7.27%
Feb-23	1.56%	5.48%
Mar-23	1.48%	4.46%
Apr-23	1.26%	3.64%
Nov-Mar	1.61%	5.38%
Apr-Oct	1.47%	5.30%

SCHEDULE "C"

ENBRIDGE GAS INC.
Union South
M12 Monthly Transportation Fuel Ratios and Fuel Rates
Firm or Interruptible Transportation Commodity
Effective July 1, 2023

Month	VT1 Easterly Dawn to Parkway (TCPL), Parkway (EGT) With Dawn Compression Fuel Ratio (%)	Fuel Rate ($/GJ)	VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression Fuel Ratio (%)	Fuel Rate ($/GJ)	M12-X Westerly Kirkwall to Dawn Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.957	0.035	0.598	0.022	0.173	0.005
May	0.681	0.024	0.408	0.014	0.173	0.005
June	0.568	0.021	0.300	0.011	0.173	0.005
July	0.552	0.020	0.286	0.010	0.173	0.005
August	0.440	0.015	0.174	0.006	0.173	0.005
September	0.435	0.015	0.174	0.006	0.173	0.005
October	0.818	0.029	0.506	0.018	0.173	0.005
November	0.975	0.035	0.683	0.024	0.173	0.005
December	1.104	0.040	0.811	0.030	0.173	0.005
January	1.271	0.045	0.962	0.035	0.173	0.005
February	1.207	0.043	0.907	0.033	0.173	0.005
March	1.127	0.041	0.812	0.030	0.173	0.005

Month	M12-X Easterly Kirkwall to Parkway (TCPL), Parkway (EGT) Fuel Ratio (%)	Fuel Rate ($/GJ)	M12-X Easterly Kirkwall to Lisgar, Parkway (Consumers) Fuel Ratio (%)	Fuel Rate ($/GJ)	M12-X Westerly Parkway to Kirkwall, Dawn Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.532	0.019	0.173	0.005	0.327	0.011
May	0.446	0.015	0.173	0.005	0.327	0.011
June	0.440	0.015	0.173	0.005	0.327	0.011
July	0.439	0.016	0.173	0.005	0.327	0.011
August	0.439	0.016	0.173	0.005	0.327	0.011
September	0.434	0.016	0.173	0.005	0.327	0.011
October	0.485	0.018	0.173	0.005	0.327	0.011
November	0.465	0.017	0.173	0.005	0.173	0.005
December	0.466	0.017	0.173	0.005	0.173	0.005
January	0.482	0.017	0.173	0.005	0.173	0.005
February	0.473	0.017	0.173	0.005	0.173	0.005
March	0.488	0.018	0.173	0.005	0.173	0.005

SCHEDULE 2
Page 1 of 1
Contract No. LST155

PRICING PROVISIONS

Shipper agrees to pay Enbridge the following for the Storage Services:

(a) **Monthly Demand Charge:** A monthly demand charge of $415,000.00 US for the period of April, 2023 to March, 2028, inclusive.

(b) **Demand Charge Escalation:** *Intentionally blank*

(c) **Variable Storage Charges:**

(i) Firm: For each GJ of gas withdrawn from or injected into the Storage Account on a firm basis, a charge equal to $0.006 CDN/GJ;

(ii) Interruptible: For each GJ of gas withdrawn from or injected into the Storage Account on an interruptible basis, a charge equal to the price set out under the heading 'If Shipper supplies fuel Commodity Charge Price/GJ' in the 'Storage Services' section under '(C) Pricing' in the MPSS (currently $0.041CDN/GJ);

(iii) Authorized Overrun: For each GJ of gas withdrawn from or injected into the Storage Account on an authorized overrun basis, a charge equal to the price set out under the heading 'If Shipper supplies fuel Commodity Charge Price/GJ' in the 'Authorized Overrun' section under '(C) Pricing' in the MPSS (currently $0.041CDN/GJ);

(iv) Dehydration Charge: Not Applicable.

(d) **Fuel:**

(i) Firm and Interruptible: For each GJ of gas withdrawn from or injected into the Storage Account on a firm or interruptible basis, an amount of fuel in kind equal to the fuel ratio set out under the heading of 'If Shipper supplies fuel' in the 'Storage Services' section under '(C) Pricing' in the MPSS (currently 0.600%).

(ii) Authorized Overrun: For each GJ of gas withdrawn from or injected into the Storage Account on an authorized overrun basis, an amount of fuel in kind equal to the fuel ratio set out under the heading of 'If Shipper supplies fuel' in the 'Authorized Overrun' section under '(C) Pricing' in the MPSS (currently 1.03%).

(e) **Late Season Balance Charge and Early Season Balance Charge:** *Intentionally blank*

(f) **Shortfall Charge:** *Intentionally blank*

(g) **Other Charges:** Any and all other charges as may be set out in this Contract, and any charges relating to Unauthorized Overrun, Drafted Storage Balance and Overrun of Maximum Storage Balance as set out in the MPSS.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2023 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
July 27, 2023

The annual charges unit charge (ACA) to be applied to in fiscal year 2024 for recovery of FY 2023 Current year and 2022 True-Up is **$0.0014** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2023.

The following calculations were used to determine the FY 2023 unit charge:

2023 CURRENT:

Estimated Program Cost $97,675,000 divided by 67,029,494,482 Dth	=	0.0014571943

2022 TRUE-UP:

Debit/Credit Cost -$1,034,580 divided by 62,791,351,082 Dth	=	(0.0000164765)
TOTAL UNIT CHARGE	=	0.0014407179

If you have any questions, please contact Raven A. Rodriguez at (202)502-6276 or e-mail at Raven.Rodriguez@ferc.gov.

PUBLIC

4.2 Rate Schedule FT-NN
Firm Transportation Service
Currently Effective Rates

	$/Dth	
	Base Tariff Rate	ACA Adj.
Reservation Charge:		
Maximum	$7.0013	N/A
Minimum	$0.0000	N/A
Commodity Charge:		
Maximum	$0.0000	a/
Minimum	$0.0000	a/
Authorized Overrun Commodity Charge:		
Maximum	$0.2302	a/
Minimum	$0.0000	a/
Fuel and Losses Percentage	0.35%	N/A
Volumetric Reservation Charge		
Maximum	$0.2302	a/
Minimum	$0.0000	a/

a/ The ACA Adj. Surcharge is revised annually and posted on the FERC website at the web address http://www.ferc.gov on the Annual Charges page of the Natural Gas Section. The ACA Adj. Surcharge is incorporated by reference in the Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Section 6.17 of the General Terms and Conditions.

Iroquois Gas Transmission System, L.P.
FERC Gas Tariff
Second Revised Volume No. 1

Fifth Revised Sheet No. 4
Superseding
Fourth Revised Sheet No. 4

---------- NON-EASTCHESTER RATES (All in $ Per Dth) ----------

	Minimum	RP19-445 Rates Maximum 1/	RP22-1065 Rates Maximum		
		Effective 4/1/2020	Effective 9/1/2022	Effective 9/1/2023	Effective 9/1/2024
RTS DEMAND (Monthly):					
Zone 1	$0.0000	$5.2357	$4.8393	$4.5655	$4.2918
Zone 2	$0.0000	$4.4878	$4.3344	$4.1823	$4.0302
Inter-Zone	$0.0000	$8.2304	$7.4217	$7.2240	$7.0567
RTS COMMODITY (Daily):					
Zone 1	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034
Zone 2	$0.0022	$0.0022	$0.0022	$0.0022	$0.0022
Inter-Zone	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056
ITS COMMODITY (Daily):					
Zone 1	$0.0034	$0.1755	$0.1625	$0.1535	$0.1445
Zone 2	$0.0022	$0.1497	$0.1447	$0.1397	$0.1347
Inter-Zone	$0.0056	$0.2762	$0.2496	$0.2431	$0.2376
VOLUMETRIC CAPACITY RELEASE (Daily) 2/:					
Zone 1	$0.0000	$0.1721	$0.1591	$0.1501	$0.1411
Zone 2	$0.0000	$0.1475	$0.1425	$0.1375	$0.1325
Inter-Zone	$0.0000	$0.2706	$0.2440	$0.2375	$0.2320

**SEE SHEET NOS. 4A, 4B, AND 4C FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

____

1/ The RP19-445 Rates that became effective 4/1/2020 shall be applicable to any Contesting Party to the Settlement dated July 27, 2022, pursuant to Section 13.3 of that Settlement.
2/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

Historic Iroquois Zone 1 Fuel Rates	
May-22	0.10%
Jun-22	0.10%
Jul-22	0.10%
Aug-22	0.20%
Sep-22	0.10%
Oct-22	0.00%
Nov-22	0.10%
Dec-22	0.20%
Jan-23	0.30%
Feb-23	0.10%
Mar-23	-0.50%
Apr-23	-1.00%
Nov-Mar	0.04%
Apr-Oct	-0.06%

STATEMENT OF NEGOTIATED RATES 1/2/4/6/

Customer Name: Northern Utilities, Inc. d/b/a Unitil

Service Agreement: 210371

Rate Schedule: MN365

Reservation Rate: Customer shall pay a negotiated reservation rate of $13.3833 per Dth, per month (equivalent to $0.44 per Dth, per Day) of Customer's MDTQ under Contract No. 210371 during the Term of Negotiated Rate.

Usage Rate and Other Charges: 3/

Term of Negotiated Rate: The term of this negotiated rate commences on January 1, 2021 and extends through December 31, 2035. 5/

Quantity ("MDTQ"): 7,500 Dth/d

Primary Receipt Point:

Beverly – Essex Co., MA (Meter No. 30035) - 7,500 Dth/d

Primary Delivery Points:

Northern Utilities – Cotton Rd – Androscoggin Co, ME (Meter No. 30028)– 7,500 Dth/d

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Pipeline's Statement of Rates for Rate Schedule MN365 at the applicable time.

FOOTNOTES:

1/ This negotiated rate transaction does not deviate in any material respect from the form of service agreement set forth in Pipeline's FERC Gas Tariff.

2/ This Negotiated Rate shall apply only to transportation service under Contract No. 210371, up to Customer's specified MDTQ, using the Primary Receipt Point and Primary Delivery Point designated herein, and any secondary receipt and delivery points available under Rate Schedule MN365.

3/ Customer shall pay: (i) a commodity charge which shall be zero for the quantity of gas, in Dekatherms, delivered during the applicable Day under Pipeline's Rate Schedule MN365; (ii) the applicable Fuel Reimbursement Quantity ("FRQ") under Pipeline's Rate Schedule MN365; (iii) the applicable Annual Charge Adjustment and all other charges and surcharges applicable to Rate Schedule MN365; and (iv) any future surcharge or additional usage charge pursuant to any FERC-approved cost recovery mechanism of general applicability implemented in a generic proceeding or in a Pipeline specific proceeding, which mechanism recovers cost components not reflected in Pipeline's recourse rate(s) applicable to service under Pipeline's Rate Schedule MN365.

4/ Pipeline and Customer agree that Contract No. 210371 is a ROFR Agreement.

5/ If the term of Contract No. 210371 renews for one or more twelve (12) month evergreen period(s) at the negotiated reservation rate, then the term of this Negotiated Rate Agreement shall be extended for such evergreen period(s).

6/ Customer will be eligible to receive reservation charge adjustments under this Negotiated Rate Agreement in accordance with Pipeline's FERC Gas Tariff.

FUEL RETAINAGE PERCENTAGES

FUEL RETAINAGE PERCENTAGE: PURSUANT TO SECTION 20 OF THE GT&C

Winter Period (November 1 - March 31)	0.81%
Non-Winter Period (April 1 - October 31)	0.98%

SCHEDULE 1

Receipt Point(s):	01-0100 Pittsburg, NH
Delivery Point(s):	05-0850 Newington Granite State
Maximum Daily Quantity:	40003 Dth/day
Maximum Contract Demand:	219176437 Dth
Effective Service Period:	April 1, 2018 through November 30, 2032

Rate Provision(s) (check if applicable rate):

__ ___ Discounted Rate

__x ___ Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

$0.6000/Dth/day

Additional Terms: Shipper shall have the right to deliver, on a secondary basis, to the following meters, at the Negotiated Rate of $0.60/Dth/day. Delivery to all other secondary delivery points on this Negotiated Rate contract shall be priced at the Maximum Recourse Rate.

Meter #	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-0725	Eliot	Granite State
05-0750	Eliot CNG	XPress Natural Gas
02-0775	Newington	Essential Power
02-0900	Newington	Eversource
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1025	Haverhill	National Grid
05-1050	Methuen	M&NE
05-1150	Dracut	Tennessee Gas Pipeline

Revision No. 2

SCHEDULE 1

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
11/1/2020	10/31/2040	10100	Pittsburg (East Hereford)	0 (Phase I Quantity) plus 0 (Phase II Quantity) plus 10,000 (Phase III Quantity)

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
11/1/2020	10/31/2040	50850	Newington Granite State	0 (Phase I Quantity) plus 0 (Phase II Quantity) plus 10,000 (Phase III Quantity)

Maximum Contract Demand	0 Dth (Phase I Quantity)
plus	0 Dth (Phase II Quantity)
plus	10,000 Dth (Phase III Quantity)
Total Maximum Contract Demand	10,000 Dth (Phase I, II and III Quantities)

Effective Service Period 1/ to 1/

Rate Provision(s) (check if applicable rate):

_______ Discounted Rate
_____X__ Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

For the period of November 1, 2020 through October 31, 2021, for volumes received at the primary receipt point and delivered to the primary delivery point, the reservation charge shall be $0.7500/Dth/day (the "Negotiated Daily Demand Rate"). For the period of November 1, 2021 through October 31, 2040, for volumes received at the primary receipt point and delivered to the primary delivery point, the Negotiated Daily Demand Rate shall be $0.7448/Dth/day.

For volumes received at the primary receipt point and delivered to any of the following secondary delivery points, the reservation charge shall be the Negotiated Daily Demand Rate: Westbrook M&NE, Westbrook Granite State, Eliot Granite State, Dracut and Haverhill Tennessee Gas. Deliveries to any other secondary delivery point(s) will be at the Recourse Reservation Rate.

Shipper shall have secondary receipt point access for delivery to any delivery point at the Recourse Reservation Rate.

In addition to the applicable reservation rate stated above, Shipper shall pay or furnish, as applicable, all maximum applicable demand and commodity surcharges, unit charges, Measurement Variance Quantities, and other fuel requirements and charges, as specified in the Tariff, in addition to any charges associated with mandated compliance with new or revised regulations or legislation (i.e. environmental, modernization and safety), which may change from time to time, and any other amounts contemplated under Article IV of this Contract.

PNGTS Construction Cost Sharing:

Shipper's Negotiated Daily Demand Rate for PNGTS reflected above shall be adjusted as follows:

To the extent Actual PNGTS Construction Costs (defined below) exceed Estimated PNGTS Construction Costs (defined below), Shipper's Negotiated Daily Demand Rate shall be multiplied by the Capital Cost Overrun Factor ("CCO Factor"). The CCO Factor shall be equal to 1 + [(CCO/EPCC) X 50%]. In no event shall the CCO Factor exceed 1.0667.

To the extent Actual PNGTS Construction Costs, as defined below, are less than Estimated PNGTS Construction Costs as defined below, Shipper's Negotiated Daily Demand Rate shall be multiplied by the Capital Cost Underrun Factor ("CCU Factor"). The CCU Factor shall be equal to 1 - [(CCU/EPCC) X 50%]. In no event shall the CCU Factor be less than 0.9333.

Any such adjustment to Shipper's Negotiated Daily Demand Rate for PNGTS shall be subject to a rate adjustment cap of +/- US$0.05 per Dth (overruns/ underruns). Such adjustment shall be effective on the actual in-service date for Phase III based on the final costs estimated by PNGTS at such time, and subsequently adjusted, if necessary, as soon as administratively feasible based on the Phase III final cost report filed with the FERC, to keep the applicable Parties financially whole as if the actual costs were known as of the actual in-service date of Phase III. Any subsequent adjustment shall not be later than the first anniversary date of the actual in-service date of Phase III and shall remain in effect for the balance of the Initial Term.

"Actual PNGTS Construction Costs" or "APCC" shall mean the amount filed by PNGTS with the FERC following completion of construction of the facilities associated with PXP Phase III (such construction shall be referred to herein as "PNGTS Construction"). PNGTS shall maintain books and records reasonably necessary for Shipper to verify the APCC.

"Capital Cost Overrun" or "CCO" shall be an amount in U.S. dollars equal to the difference between the Actual PNGTS Construction Costs and the Estimated PNGTS Construction Costs, if Actual PNGTS Construction Costs exceed Estimated Project Costs.

“Capital Cost Underrun” or “CCU” shall be an amount in U.S. dollars equal to the difference between the Actual PNGTS Construction Costs and the Estimated PNGTS Construction Costs, if Actual PNGTS Construction Costs are less than Estimated PNGTS Construction Costs.

“Estimated PNGTS Construction Costs” or “EPCC” shall mean all costs and expenses that are projected to be incurred by PNGTS to complete the PNGTS Construction in the manner contemplated by this Agreement as filed with the FERC in its Section 7 of the Natural Gas Act certificate application for Phase III.

Shipper shall have one-time audit right to be exercised no later than thirteen (13) months after the actual in-service date for Phase III, at Shipper’s sole cost and expense, to review PNGTS’s books and records as reasonably necessary to verify costs associated with Phase III of the PNGTS Construction for purposes of this provision.

Historic PNGTS Measurement Variance Rates

May-22	-0.30%
Jun-22	-0.10%
Jul-22	0.70%
Aug-22	0.20%
Sep-22	0.40%
Oct-22	-0.60%
Nov-22	-0.50%
Dec-22	0.70%
Jan-23	-0.10%
Feb-23	-0.30%
Mar-23	0.00%
Apr-23	0.30%
Annual	0.03%
Projected (Greater of Annual Average or 0%)	0.03%
PXP Project Fuel Rate	0.28%
WXP Project Fuel Rate	1.336%

PNGTS
Docket No. CP18-____-000
Exhibit Z-2
Page 1 of 3

Portland Natural Gas Transmission System
Portland XPress Project (PXP) Phase III
Project Fuel Study

M&N Operating Company, LLC, the operator of the Joint Facilities between Westbrook and Dracut, estimated the daily fuel consumption for PXP. The result of the study is shown on Line 3 below. The proposed initial Fuel Rate was calculated by dividing the total estimated daily fuel consumption by the estimated daily volume to be transported on the Joint Facilities.

Once in service, the Fuel Rate will be adjusted monthly pursuant to proposed Section 6.2.26 of the General Terms & Conditions of PNGTS's FERC Gas Tariff, Third Revised Volume No. 1, so that the Fuel Rate is based upon actual fuel usage and transportation activity. Currently, the PNGTS system has no compression facilities and therefore shippers only pay a charge related to Lost And Unaccounted For Gas.

Line No.	Description		
1	Installed Horsepower	6,300	hp
2	PXP Volume Transported on both Northern Facilities and Joint Facilities	119,378	Dth/d
3	Estimated Fuel	296.2	Dth/d
4	Assumed Load Factor	90%	
5	Initial Compressor Fuel Rate	0.28%	

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/
FT	Recourse Reservation Rate		
	-- Maximum	$25.9843	---------
	-- Minimum	$00.0000	---------
	Seasonal Recourse Reservation Rate		
	-- Maximum	$49.3701	---------
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$00.0000	2/
	-- Minimum	$00.0000	2/
	-- PXP Project	$00.0091	
FT-FLEX	Recourse Reservation Rate		
	--Maximum	$17.4406	---------
	--Minimum	$00.0000	---------
	Recourse Usage Rate		
	--Maximum	$00.2809	2/
	--Minimum	$00.0000	2/

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE FACTOR-LAUF:

Minimum down to -1.00%
Maximum up to +1.00%

MEASUREMENT VARIANCE FACTOR-FUEL 3/

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

2/ The currently effective ACA unit charge as published on the Commission’s website (www.ferc.gov) is incorporated herein by reference.

3/ Measurement Variance Factor-Fuel shall be calculated in accordance with Section 6.2.26 herein and shall apply to Rate Schedule FT-Firm Transportation Service PXP contracts with primary point rights on the Joint Facilities, and Phase II and Phase III Rate Schedule FT-Firm Transportation Service WXP contracts, as applicable.

Revision No. 0

SCHEDULE 1

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
1/	1/	10100	PITTSBURG (EAST HEREFORD)	10,000

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
1/	1/	51150	DRACUT, MASSACHUSETTTS	10,000

Maximum Contract Demand 10,000 Dth

Effective Service Period 1/ to 1/

Rate Provision(s) (check if applicable rate):

___X___ Discounted Rate
_______ Negotiated Rate

Shipper's charges and fees shall be calculated as follows:
For ___1/_____ to __1/______, shipper agrees to pay a fixed discounted daily demand rate of $0.8200 per Dth ("Discounted Daily Demand Rate") multiplied by the sum of the Maximum Daily Quantity during such term.

Other terms and conditions:

In addition to the Discounted Daily Demand Rate, Shipper shall pay all maximum applicable demand and commodity surcharges, including but not limited to measurement variance and unit charges, specified under Rate Schedule FT set forth in the Tariff, in addition to any charges associated with mandated compliance with new or revised regulations or legislation (i.e. environmental, modernization and safety) (collectively, the "Project Rate").

If during the term in Article VII, Transporter's maximum recourse rate under Rate Schedule FT set forth in the Tariff for a route from the Primary Receipt Point to the Primary Delivery Point is, or is expected to be, lower than the fixed $0.8200/Dth/day then Transporter may, at its discretion, require Shipper to convert its Discounted Daily Demand Rate to a fixed negotiated daily reservation rate equal to $0.8200/Dth/day (the "Converted Negotiated Demand Rate"), and Shipper would continue to pay all other components of the Project Rate without modification thereto. The Parties expressly agree that if a conversion to the Converted Negotiated Demand Rate occurs, it shall not make Shipper responsible for any charges or surcharges above and beyond the Project Rate which it otherwise would not be responsible for prior to such conversion. If during the term in Article VII and after Transporter requires Shipper to convert its Discounted Daily Demand Rate to the Converted Negotiated Demand Rate, the maximum Tariff recourse rate under Rate Schedule FT set forth in the Tariff for a route from Primary Receipt Point to the Primary Delivery Point is, or is expected to be, greater than the Discounted Daily Demand Rate was prior to such conversion, Transporter may, at its discretion, require Shipper to convert is Converted Negotiated Demand Rate back to Discounted Daily Demand Rate.

Secondary Receipt Points:

Shipper shall have secondary receipt point access on Transporter's system pursuant to the terms and conditions of Transporter's Tariff, at the Project Rate.

Secondary Delivery Points:

Shipper shall have secondary delivery point access on Transporter's system pursuant to the terms and conditions of Transporter's Tariff at the Project Rate.

1/ Pursuant to Article VII of the Contract.

Portland Natural Gas Transmission System
Westbrook XPress (WXP) Phase II and III
Project Measurement Variance Factor-Fuel Study

Line No.	Description			
1	Installed Horsepower		15,900	hp
2	WXP Incremental Project Capacity	1/	80,998	Mcf/d
3	Assumed Load Factor Range		75% to 100%	
4	Estimated Fuel Usage Range		0 to 1,082	Mcf/d
5	WXP Project Measurement Variance Factor-Fuel Rate Range	2/	0.000% to 1.336%	

Notes:

1/ See page 1 of the Application for a Certificate of Public Convenience and Necessity; 80,998 Mcf/d represents the requested increase to certificated capacity on PNGTS's wholly-owned north system from Pittsburg, New Hampshire, to Westbrook, Maine.

2/ (Ln. 4 x 365) / (Ln. 2 x Ln. 3 x 365). The low value of the range was calculated utilizing a 75% load factor, and the high value of the range utilized a 100% load factor. PNGTS anticipates an initial WXP Project fuel rate within the reflected range. Subsequent monthly fuel rates will be adjusted in accordance with the PNGTS fuel mechanism as proposed in this certificate application, and are intended to keep Phase II and III WXP Project shippers and PNGTS whole on a rolling monthly basis.

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, EIGHTH REVISED VOLUME NO. 1

FT-1
RESERVATION
CHARGES

Pursuant to Sections 3.2(A), 3.3(A), and 3.5 of Rate Schedule FT-1:

	FT-1 RESERVATION CHARGE* $/dth		FT-1 RESERVATION CHARGE ADJUSTMENT $/dth	
ACCESS AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
STX-AAB	10.0130	0.0000	0.3292	0.0000
WLA-AAB	4.7580	0.0000	0.1564	0.0000
ELA-AAB	2.9490	0.0000	0.0969	0.0000
ETX-AAB	3.1710	0.0000	0.1042	0.0000
STX-STX	6.3800	0.0000	0.2097	0.0000
STX-WLA	8.0880	0.0000	0.2659	0.0000
STX-ELA	9.5210	0.0000	0.3131	0.0000
STX-ETX	9.5210	0.0000	0.3130	0.0000
WLA-WLA	3.1510	0.0000	0.1036	0.0000
WLA-ELA	4.5830	0.0000	0.1506	0.0000
WLA-ETX	4.5270	0.0000	0.1488	0.0000
ELA-ELA	2.8740	0.0000	0.0945	0.0000
ETX-ETX	3.0850	0.0000	0.1015	0.0000
ETX-ELA	2.8780	0.0000	0.0946	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.5710	0.0000	0.1175	0.0000
M1-M2	8.6180	0.0000	0.2833	0.0000
M1-M3	16.6770	0.0000	0.5483	0.0000
M2-M2	6.4890	0.0000	0.2133	0.0000
M2-M3	14.5480	0.0000	0.4783	0.0000
M3-M3	9.5020	0.0000	0.3124	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, EIGHTH REVISED VOLUME NO. 1

FT-1
USAGE
CHARGES

ZONE RATE
$/dth

Pursuant to Sections 3.2(A) and 3.3(A) of Rate Schedule FT-1:

	STX	WLA	ELA	ETX	M1	M2	M3
USAGE-1 - MAXIMUM							
from STX	0.0219	0.0254	0.0424	0.0424	0.0642	0.1088	0.1788
from WLA	0.0254	0.0098	0.0274	0.0274	0.0492	0.0938	0.1638
from ELA	0.0424	0.0274	0.0212	0.0212	0.0430	0.0876	0.1576
from ETX	0.0424	0.0274	0.0212	0.0212	0.0430	0.0876	0.1576
from M1	0.0642	0.0492	0.0430	0.0430	0.0218	0.0664	0.1363
from M2	0.1088	0.0938	0.0876	0.0876	0.0664	0.0475	0.1180
from M3	0.1788	0.1638	0.1576	0.1576	0.1363	0.1180	0.0735
USAGE-1 - MINIMUM							
from STX	0.0189	0.0224	0.0394	0.0394	0.0582	0.1028	0.1728
from WLA	0.0224	0.0068	0.0245	0.0245	0.0433	0.0879	0.1579
from ELA	0.0394	0.0245	0.0183	0.0183	0.0371	0.0817	0.1517
from ETX	0.0394	0.0245	0.0183	0.0183	0.0371	0.0817	0.1517
from M1	0.0582	0.0433	0.0371	0.0371	0.0188	0.0634	0.1333
from M2	0.1028	0.0879	0.0817	0.0817	0.0634	0.0445	0.1150
from M3	0.1728	0.1579	0.1517	0.1517	0.1333	0.1150	0.0705
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0205						
from WLA		0.0093					
from ELA			0.0199				
from ETX				0.0199			
from M1				0.0422	0.0210		
from M2				0.0849	0.0637	0.0456	
from M3						0.1128	0.0702
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0175						
from WLA		0.0063					
from ELA			0.0170				
from ETX				0.0170			
from M1				0.0363	0.0180		
from M2				0.0790	0.0607	0.0426	
from M3						0.1098	0.0672
USAGE-2	0.2209	0.2209	0.2209	0.2209	0.3601	0.5706	0.9055

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: December 1 through March 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	1.09	1.25	2.12	2.12	3.08	4.70	5.81
Base	from WLA	0.50	0.50	1.38	1.38	2.34	3.96	5.07
Applicable	from ELA	1.05	1.05	1.05	1.05	2.01	3.63	4.74
Shrinkage	from ETX	1.09	1.05	1.05	1.05	2.01	3.63	4.74
Percentage	from M1	3.08	2.34	2.01	2.01	0.96	2.58	3.69
|	from M2	4.70	3.96	3.63	3.63	2.58	1.80	2.90
|	from M3	5.81	5.07	4.74	4.74	3.69	2.90	1.28
|	from STX	-0.93	-1.06	-1.78	-1.78	-2.57	-3.8	-4.29
Applicable	from WLA	-0.31	-0.44	-1.14	-1.14	-1.93	-3.16	-3.65
Shrinkage	from ELA	-0.71	-0.81	-0.77	-0.77	-1.56	-2.79	-3.28
Adjustment	from ETX	-0.75	-0.81	-0.77	-0.77	-1.56	-2.79	-3.28
Percentage	from M1	-2.57	-1.93	-1.56	-1.56	-0.79	-2.02	-2.51
|	from M2	-3.80	-3.16	-2.79	-2.79	-2.02	-1.41	-1.88
|	from M3	-4.29	-3.65	-3.28	-3.28	-2.51	-1.88	-0.65
|	from STX	0.16	0.19	0.34	0.34	0.51	0.90	1.52
Applicable	from WLA	0.19	0.06	0.24	0.24	0.41	0.80	1.42
Shrinkage	from ELA	0.34	0.24	0.28	0.28	0.45	0.84	1.46
Percentage	from ETX	0.34	0.24	0.28	0.28	0.45	0.84	1.46
|	from M1	0.51	0.41	0.45	0.45	0.17	0.56	1.18
|	from M2	0.90	0.80	0.84	0.84	0.56	0.39	1.02
|	from M3	1.52	1.42	1.46	1.46	1.18	1.02	0.63

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				0.28			
Percentage	from M1				0.28	0.00		
|	from M2				0.28	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				0.28			
|	from M1				0.28	0.00		
|	from M2				0.28	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.86 %	-1.99 %	0.87 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.20 %	0.56 %
Monthly Injections	1.76 %	-1.20 %	0.56 %
Monthly Inventory Level	0.08 %	-0.03 %	0.05 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Spring, Summer and Fall Periods: April 1 through November 30

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
Base Applicable Shrinkage Percentage	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
Applicable Shrinkage Adjustment Percentage	from STX	-0.81	-0.90	-1.39	-1.39	-2.12	-2.92	-3.20
	from WLA	-0.39	-0.48	-0.95	-0.95	-1.68	-2.48	-2.76
	from ELA	-0.66	-0.73	-0.70	-0.70	-1.43	-2.23	-2.51
	from ETX	-0.68	-0.73	-0.70	-0.70	-1.43	-2.23	-2.51
	from M1	-2.12	-1.68	-1.43	-1.43	-0.73	-1.53	-1.81
	from M2	-2.92	-2.48	-2.23	-2.23	-1.53	-1.12	-1.41
	from M3	-3.20	-2.76	-2.51	-2.51	-1.81	-1.41	-0.60
Applicable Shrinkage Percentage	from STX	0.12	0.14	0.25	0.25	0.37	0.67	1.14
	from WLA	0.14	0.05	0.18	0.18	0.30	0.60	1.07
	from ELA	0.25	0.18	0.21	0.21	0.33	0.63	1.10
	from ETX	0.25	0.18	0.21	0.21	0.33	0.63	1.10
	from M1	0.37	0.30	0.33	0.33	0.12	0.42	0.89
	from M2	0.67	0.60	0.63	0.63	0.42	0.30	0.76
	from M3	1.14	1.07	1.10	1.10	0.89	0.76	0.47

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
Base Applicable Shrinkage Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				0.00			
	from M1				0.00	0.00		
	from M2				0.00	0.00	0.00	
	from M3						0.00	0.00
Applicable Shrinkage Adjustment Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				0.21			
	from M1				0.21	0.00		
	from M2				0.21	0.00	0.00	
	from M3						0.00	0.00
Applicable Shrinkage Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				0.21			
	from M1				0.21	0.00		
	from M2				0.21	0.00	0.00	
	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-1.91 %	0.79 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.20 %	0.56 %
Monthly Injections	1.76 %	-1.20 %	0.56 %
Monthly Inventory Level	0.08 %	-0.03 %	0.05 %

Footnote: Due to the bidirectional flow patterns of Pipeline’s Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Twenty First Revised Sheet No. 14
Superseding
Twentieth Revised Sheet No. 14

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base
Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.6943		$9.80960	$13.1952	$13.4288	$14.7555	$15.6623	$19.6507
L		$4.1674						
1	$7.0668		$6.7741	$9.0149	$12.7706	$12.5770	$14.1840	$17.4413
2	$13.1953		$8.9608	$4.6605	$4.3567	$5.5746	$7.6672	$9.8974
3	$13.4288		$7.0978	$4.6982	$3.3894	$5.2064	$9.4162	$10.8807
4	$17.0500		$15.7186	$5.9901	$9.1033	$4.4560	$4.8190	$6.8844
5	$20.3297		$14.2853	$6.2836	$7.6032	$4.9501	$4.6433	$6.0448
6	$23.5176		$16.4078	$11.2924	$12.4403	$8.7873	$4.6228	$4.0017

Daily Base
Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1543		$0.3225	$0.4338	$0.4415	$0.4851	$0.5149	$0.6461
L		$0.1370						
1	$0.2323		$0.2227	$0.2964	$0.4199	$0.4135	$0.4663	$0.5734
2	$0.4338		$0.2946	$0.1532	$0.1432	$0.1833	$0.2521	$0.3254
3	$0.4415		$0.2334	$0.1545	$0.1114	$0.1712	$0.3096	$0.3577
4	$0.5605		$0.5168	$0.1969	$0.2993	$0.1465	$0.1584	$0.2263
5	$0.6684		$0.4697	$0.2066	$0.2500	$0.1627	$0.1527	$0.1987
6	$0.7732		$0.5394	$0.3713	$0.4090	$0.2889	$0.1520	$0.1316

Maximum Reservation
Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.7400		$9.8553	$13.2409	$13.4745	$14.8012	$15.7080	$19.6964
L		$4.2131						
1	$7.1125		$6.8198	$9.0606	$12.8163	$12.6227	$14.2297	$17.4870
2	$13.2410		$9.0065	$4.7062	$4.4024	$5.6203	$7.7129	$9.9431
3	$13.4745		$7.1435	$4.7439	$3.4351	$5.2521	$9.4619	$10.9264
4	$17.0957		$15.7643	$6.0358	$9.1490	$4.5017	$4.8647	$6.9301
5	$20.3754		$14.3310	$6.3293	$7.6489	$4.9958	$4.6890	$6.0905
6	$23.5633		$16.4535	$11.3381	$12.4860	$8.8330	$4.6685	$4.0474

Notes:

1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0457.

Issued: September 27, 2022
Effective: November 1, 2022

Docket No. RP22-1245-000
Accepted: October 20, 2022

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Twenty Third Revised Sheet No. 15
Superseding
Twenty Second Revised Sheet No. 15

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2260	$0.2157	$0.2567
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.1922	$0.1960	$0.2238
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0622	$0.0997	$0.1105
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0831	$0.1150	$0.1256
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0385	$0.0544	$0.0881
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0541	$0.0536	$0.0666
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0833	$0.0452	$0.0274

Minimum Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Maximum Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.2278	$0.2175	$0.2585
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.1940	$0.1978	$0.2256
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0640	$0.1015	$0.1123
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.0849	$0.1168	$0.1274
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0403	$0.0562	$0.0899
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0559	$0.0554	$0.0684
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.0851	$0.0470	$0.0292

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0018.

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.43%		1.41%	2.12%	2.67%	3.21%	3.51%	4.17%
L		0.20%						
1	0.55%		1.01%	1.78%	2.15%	2.63%	3.19%	3.64%
2	2.16%		1.08%	0.19%	0.39%	0.75%	1.30%	1.78%
3	2.67%		2.15%	0.39%	0.08%	1.06%	1.53%	2.04%
4	3.11%		2.44%	1.08%	1.29%	0.40%	0.64%	1.13%
5	3.63%		3.19%	1.32%	1.55%	0.63%	0.63%	0.81%
6	4.34%		3.77%	1.78%	2.04%	1.05%	0.49%	0.23%

Broad Run Expansion Project – Market Component (Z3-Z1): 5/ 6.50%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0041		$0.0158	$0.0245	$0.0304	$0.0368	$0.0418	$0.0502
L		$0.0014						
1	$0.0055		$0.0111	$0.0203	$0.0248	$0.0308	$0.0377	$0.0433
2	$0.0245		$0.0119	$0.0013	$0.0036	$0.0080	$0.0146	$0.0199
3	$0.0304		$0.0248	$0.0036	$0.0000	$0.0116	$0.0173	$0.0230
4	$0.0368		$0.0284	$0.0118	$0.0144	$0.0038	$0.0066	$0.0124
5	$0.0418		$0.0377	$0.0146	$0.0173	$0.0065	$0.0065	$0.0086
6	$0.0502		$0.0433	$0.0199	$0.0230	$0.0116	$0.0049	$0.0018

Broad Run Expansion Project – Market Component (Z3-Z1): 5/ $0.0828

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.04%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.04%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
5/ The incremental F&LR and EPCR set forth above are applicable to a Shipper(s) utilizing capacity on the Broad Run Expansion Project – Market Component facilities, from any receipt point(s) to any delivery point(s) located on the project's transportation path. Any service provided to a Shipper(s) outside the project's transportation path shall be subject to the greater of the incremental F&LR and EPCR for the project or the applicable F&LR and EPCR for the applicable receipt(s) and delivery point(s) as shown in the rate matrices above. Included in the above F&LR is the Losses component of the F&LR equal to 0.04%.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$1.7226	$1.7226 1/		
Space Rate	$0.0175	$0.0175 1/		
Injection Rate	$0.0073	$0.0073	1.29%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.2067	$0.2067 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.2655	$1.2655 1/		
Space Rate	$0.0173	$0.0173 1/		
Injection Rate	$0.0087	$0.0087	1.29%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1519	$0.1519 1/		

Notes:

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to -0.06%.

Winter Period Re-Entry Surcharge Calculation
(Applicable to Capacity Assigned Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	**Weighted Average**	Reference
1	Winter Demand Cost of Gas Rate	$ 0.1706	$ 0.2275	$ 0.2191	See Summary, Winter Demand Cost of Gas Rate for HLF and LLF, respectively
2	Winter Commodity Cost of Gas Rate	$ 0.5040	$ 0.5286	$ 0.5250	See Summary, Winter Commodity Cost of Gas Rate for HLF and LLF, respectively
3	Winter Indirect Cost of Gas	$ 0.0272	$ 0.0272	$ 0.0272	See Summary, Winter Indirect Cost of Gas Rate, Less Prior Period Credits
4	Winter Cost of Gas Rate (Exclusive of Credits)	$ 0.7018	$ 0.7833	$ 0.7713	Sum Lines 1 through 3
5	Winter Cost of Gas Rate for Incumbent Sales Customers	$ 0.6587	$ 0.7402	$ 0.7282	See Summary, Winter Total Cost of Gas Rate for HLF and LLF, respectively
6	**Winter Re-Entry Surcharge**	$ 0.0431	$ 0.0431	**$ 0.0431**	**Positive Difference between Line 4 and Line 5**
7	Projected Sales (therms)	2,480,131	14,311,515	16,791,646	See Summary, Winter Projected Prorated Sales for HLF and LLF, respectively

Summer Period Re-Entry Surcharge & Conversion Surcharge Calculation
(Applicable to Capacity Assigned & Capacity Exempt Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	**Weighted Average**	Reference
8	Summer Demand Cost of Gas Rate	$ 0.1381	$ 0.2560	$ 0.2386	See Summary, Summer Demand Cost of Gas Rate for HLF and LLF, respectively
9	Summer Commodity Cost of Gas Rate	$ 0.2510	$ 0.2510	$ 0.2510	See Summary, Summer Commodity Cost of Gas Rate for HLF and LLF, respectively
10	Summer Indirect Cost of Gas	$ 0.0552	$ 0.0552	$ 0.0552	See Summary, Summer Indirect Cost of Gas Rate, Less Prior Period Credits
11	Summer Cost of Gas Rate (Exclusive of Credits)	$ 0.4443	$ 0.5622	$ 0.5448	Sum Lines 8 through 10
12	Summer Cost of Gas Rate for Incumbent Sales Customers	$ 0.4443	$ 0.5622	$ 0.5448	Lines 91 and 111 of Summary
13	**Summer Re-Entry Surcharge**	$ -	$ -	**$ 0.0000**	**Positive Difference between Line 11 and Line 12**
14	Projected Sales (therms)	1,861,021	2,486,344	4,347,365	See Summary, Summer Projected Prorated Sales for HLF and LLF, respectively

Winter Period Conversion Surcharge Calculation
(Applicable to Capacity Exempt Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Reference
1	LLF Winter Demand Cost of Gas Rate	$ 0.2275	$ 0.2275	See Summary, Winter Demand Cost of Gas Rate for LLF
2	LLF Winter Commodity Cost of Gas Rate	$ 0.5286	$ 0.5286	See Summary, Winter Commodity Cost of Gas Rate for LLF
3	LLF Winter Indirect Cost of Gas	$ 0.0272	$ 0.0272	See Summary, Winter Indirect Cost of Gas Rate, Less Prior Period Credits
4	Floor Price (LLF Winter Cost of Gas Rate, Exclusive of Credits)	$ 0.7833	$ 0.7833	Sum Lines 1 through 3.
5	Total Incremental Cost	$ 1.2277	$ 1.2277	See Line 15 of Incremental Commodity Price Worksheet
6	Total Conversion Rate	$ 1.2277	$ 1.2277	Maximum of Line 4 and Line 5
7	Winter Gas Adjustment Factor for Incumbent Sales Customers	$ 0.6587	$ 0.7402	See Summary, Winter Total Cost of Gas Rate for HLF and LLF, respectively
8	**Conversion Surcharge**	**$ 0.5690**	**$ 0.4875**	**Positive Difference between Line 6 and Line 7**

Incremental Commodity Price Worksheet

Line	Month	9/5/2023 NYMEX Settlement	Projected PNGTS Delivered Basis (7/31/2023 Algonquin Basis plus $0.75 per Dth)	Projected FOM Index	Projected Non-Capacity Assigned Delivery Service Loads	Comments
1	Nov-23	$ 2.991	$ 2.950	$ 5.941	215,092	
2	Dec-23	$ 3.453	$ 9.090	$ 12.543	225,487	
3	Jan-24	$ 3.706	$ 13.280	$ 16.986	244,130	
4	Feb-24	$ 3.634	$ 12.000	$ 15.634	229,129	
5	Mar-24	$ 3.328	$ 4.958	$ 8.286	225,467	
6	Apr-24	$ 3.052	$ 1.593	$ 4.645	215,177	
7	Winter Period Weigthed Average Baseload Price ($/Dth)			$ 10.855	1,354,482	Average, Weighted by Loads, Lines 1 through 6
8	Load Shape Price Factor			1.030		See Load Shape Price Factor Worksheet
9	Winter Period Incremental Load Shape Price ($/Dth)			$ 11.181		Line 7 times Line 8
10	Granite Fuel			0.35%		Granite Tariff
11	Granite Variable Transport ($/Dth)			$ 0.2316		Granite Tariff (IT Daily Rate plus ACA)
12	Northern City-Gate Price ($/Dth)			$ 11.452		Line 9 times (1 plus Line 10) plus Line 11
13	New Hampshire Division City-Gate Sendout to Sales Ratio			1.0720		1 plus Company Gas Allowance, FXW-3
14	Northern Retail Meter Price ($/Dth)			$ 12.277		Line 12 times Line 13
15	Northern Retail Meter Price ($/therm)			$ 1.2277		Line 14 divided by 10

Load Shape Price Factor Worksheet

Month	Date	Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
		Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Nov-22	11/1/2022	4,039	7,494	11,533	-	7,494	7,494	$ 3.870	$ 29,002
Nov-22	11/2/2022	4,836	8,049	12,885	-	8,049	8,049	$ 3.515	$ 28,292
Nov-22	11/3/2022	4,652	6,958	11,610	-	6,958	6,958	$ 3.685	$ 25,640
Nov-22	11/4/2022	3,182	6,693	9,875	-	6,693	6,693	$ 2.420	$ 16,197
Nov-22	11/5/2022	2,507	6,033	8,540	-	6,033	6,033	$ 0.735	$ 4,434
Nov-22	11/6/2022	2,687	6,087	8,774	-	6,087	6,087	$ 0.735	$ 4,474
Nov-22	11/7/2022	4,333	6,979	11,312	-	6,979	6,979	$ 0.735	$ 5,130
Nov-22	11/8/2022	6,684	7,982	14,666	-	7,982	7,982	$ 3.860	$ 30,811
Nov-22	11/9/2022	6,274	8,037	14,311	-	8,037	8,037	$ 3.460	$ 27,808
Nov-22	11/10/2022	3,865	7,625	11,490	-	7,625	7,625	$ 2.320	$ 17,690
Nov-22	11/11/2022	2,769	6,517	9,286	-	6,517	6,517	$ 4.110	$ 26,785
Nov-22	11/12/2022	3,328	5,260	8,588	-	5,260	5,260	$ 4.110	$ 21,619
Nov-22	11/13/2022	6,420	6,639	13,059	-	6,639	6,639	$ 4.110	$ 27,286
Nov-22	11/14/2022	7,877	8,609	16,486	-	8,609	8,609	$ 4.110	$ 35,383
Nov-22	11/15/2022	6,898	8,127	15,025	-	8,127	8,127	$ 6.535	$ 53,110
Nov-22	11/16/2022	6,864	7,935	14,799	-	7,935	7,935	$ 6.445	$ 51,141
Nov-22	11/17/2022	7,561	8,472	16,033	-	8,472	8,472	$ 7.575	$ 64,175
Nov-22	11/18/2022	7,332	8,185	15,517	-	8,185	8,185	$ 8.205	$ 67,158
Nov-22	11/19/2022	7,206	7,162	14,368	-	7,162	7,162	$ 11.600	$ 83,079
Nov-22	11/20/2022	8,518	7,769	16,287	-	7,769	7,769	$ 11.600	$ 90,120
Nov-22	11/21/2022	7,690	8,469	16,159	-	8,469	8,469	$ 11.600	$ 98,240
Nov-22	11/22/2022	6,950	8,461	15,411	-	8,461	8,461	$ 10.795	$ 91,336
Nov-22	11/23/2022	6,714	6,520	13,234	-	6,520	6,520	$ 8.655	$ 56,431
Nov-22	11/24/2022	5,443	4,731	10,174	-	4,731	4,731	$ 6.800	$ 32,171
Nov-22	11/25/2022	4,671	4,703	9,374	-	4,703	4,703	$ 6.800	$ 31,980
Nov-22	11/26/2022	4,900	6,400	11,300	-	6,400	6,400	$ 6.800	$ 43,520
Nov-22	11/27/2022	4,663	6,392	11,055	-	6,392	6,392	$ 6.800	$ 43,466
Nov-22	11/28/2022	6,746	8,551	15,297	-	8,551	8,551	$ 6.800	$ 58,147
Nov-22	11/29/2022	6,712	8,945	15,657	-	8,945	8,945	$ 5.855	$ 52,373

Load Shape Price Factor Worksheet

Month	Date	Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
		Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Nov-22	11/30/2022	6,170	7,896	14,066	-	7,896	7,896	$ 6.560	$ 51,798
Dec-22	12/1/2022	7,676	8,993	16,669	-	8,993	8,993	$ 9.905	$ 89,076
Dec-22	12/2/2022	6,374	7,798	14,172	-	7,798	7,798	$ 6.225	$ 48,543
Dec-22	12/3/2022	5,397	6,603	12,000	-	6,603	6,603	$ 5.990	$ 39,552
Dec-22	12/4/2022	7,788	7,593	15,381	-	7,593	7,593	$ 5.990	$ 45,482
Dec-22	12/5/2022	6,873	8,222	15,095	-	8,222	8,222	$ 5.990	$ 49,250
Dec-22	12/6/2022	5,534	7,169	12,703	-	7,169	7,169	$ 4.255	$ 30,504
Dec-22	12/7/2022	5,246	7,263	12,509	-	7,263	7,263	$ 4.010	$ 29,125
Dec-22	12/8/2022	7,584	8,531	16,115	-	8,531	8,531	$ 4.890	$ 41,717
Dec-22	12/9/2022	7,429	8,176	15,605	-	8,176	8,176	$ 6.475	$ 52,940
Dec-22	12/10/2022	8,571	8,783	17,354	-	8,783	8,783	$ 12.545	$ 110,183
Dec-22	12/11/2022	9,387	7,392	16,779	-	7,392	7,392	$ 12.545	$ 92,733
Dec-22	12/12/2022	9,263	9,059	18,322	-	9,059	9,059	$ 12.545	$ 113,645
Dec-22	12/13/2022	8,444	9,123	17,567	-	9,123	9,123	$ 18.930	$ 172,698
Dec-22	12/14/2022	7,851	8,560	16,411	-	8,560	8,560	$ 21.520	$ 184,211
Dec-22	12/15/2022	7,110	8,097	15,207	-	8,097	8,097	$ 10.170	$ 82,346
Dec-22	12/16/2022	7,611	8,135	15,746	-	8,135	8,135	$ 8.590	$ 69,880
Dec-22	12/17/2022	7,301	7,561	14,862	-	7,561	7,561	$ 17.270	$ 130,578
Dec-22	12/18/2022	7,867	8,081	15,948	-	8,081	8,081	$ 17.270	$ 139,559
Dec-22	12/19/2022	8,373	7,975	16,348	-	7,975	7,975	$ 17.270	$ 137,728
Dec-22	12/20/2022	8,476	8,667	17,143	-	8,667	8,667	$ 13.550	$ 117,438
Dec-22	12/21/2022	8,500	8,416	16,916	-	8,416	8,416	$ 10.520	$ 88,536
Dec-22	12/22/2022	6,636	7,353	13,989	-	7,353	7,353	$ 6.610	$ 48,603
Dec-22	12/23/2022	8,416	8,453	16,869	-	8,453	8,453	$ 30.250	$ 255,703
Dec-22	12/24/2022	9,993	6,030	16,023	-	6,030	6,030	$ 34.900	$ 210,447
Dec-22	12/25/2022	8,746	5,293	14,039	-	5,293	5,293	$ 34.900	$ 184,726
Dec-22	12/26/2022	8,876	7,737	16,613	-	7,737	7,737	$ 34.900	$ 270,021
Dec-22	12/27/2022	8,965	8,341	17,306	-	8,341	8,341	$ 34.900	$ 291,101
Dec-22	12/28/2022	8,395	8,504	16,899	-	8,504	8,504	$ 17.215	$ 146,396

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
Month	Date	Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Dec-22	12/29/2022	7,317	7,771	15,088	-	7,771	7,771	$ 5.410	$ 42,041
Dec-22	12/30/2022	4,334	6,245	10,579	-	6,245	6,245	$ 3.625	$ 22,638
Dec-22	12/31/2022	3,859	5,699	9,558	-	5,699	5,699	$ 3.625	$ 20,659
Jan-23	1/1/2023	5,707	4,692	10,399	-	4,692	4,692	$ 2.965	$ 13,912
Jan-23	1/2/2023	7,239	6,749	13,988	-	6,749	6,749	$ 2.965	$ 20,011
Jan-23	1/3/2023	7,269	8,557	15,826	-	8,557	8,557	$ 2.965	$ 25,372
Jan-23	1/4/2023	6,915	8,996	15,911	-	8,996	8,996	$ 2.945	$ 26,493
Jan-23	1/5/2023	8,345	9,428	17,773	-	9,428	9,428	$ 4.040	$ 38,089
Jan-23	1/6/2023	7,630	8,097	15,727	-	8,097	8,097	$ 5.125	$ 41,497
Jan-23	1/7/2023	7,658	7,251	14,909	-	7,251	7,251	$ 4.555	$ 33,028
Jan-23	1/8/2023	8,315	8,044	16,359	-	8,044	8,044	$ 4.555	$ 36,640
Jan-23	1/9/2023	8,050	8,040	16,090	-	8,040	8,040	$ 4.555	$ 36,622
Jan-23	1/10/2023	9,686	9,119	18,805	-	9,119	9,119	$ 7.250	$ 66,113
Jan-23	1/11/2023	9,254	8,313	17,567	-	8,313	8,313	$ 6.560	$ 54,533
Jan-23	1/12/2023	6,674	7,061	13,735	-	7,061	7,061	$ 3.375	$ 23,831
Jan-23	1/13/2023	6,399	7,146	13,545	-	7,146	7,146	$ 3.665	$ 26,190
Jan-23	1/14/2023	7,819	7,604	15,423	-	7,604	7,604	$ 7.150	$ 54,369
Jan-23	1/15/2023	8,238	7,981	16,219	-	7,981	7,981	$ 7.150	$ 57,064
Jan-23	1/16/2023	8,541	7,843	16,384	-	7,843	7,843	$ 7.150	$ 56,077
Jan-23	1/17/2023	7,182	8,103	15,285	-	8,103	8,103	$ 7.150	$ 57,936
Jan-23	1/18/2023	7,190	8,049	15,239	-	8,049	8,049	$ 4.190	$ 33,725
Jan-23	1/19/2023	7,633	7,948	15,581	-	7,948	7,948	$ 3.280	$ 26,069
Jan-23	1/20/2023	8,547	8,260	16,807	-	8,260	8,260	$ 5.430	$ 44,852
Jan-23	1/21/2023	8,984	8,192	17,176	-	8,192	8,192	$ 4.025	$ 32,973
Jan-23	1/22/2023	8,181	8,078	16,259	-	8,078	8,078	$ 4.025	$ 32,514
Jan-23	1/23/2023	8,796	9,616	18,412	-	9,616	9,616	$ 4.025	$ 38,704
Jan-23	1/24/2023	8,292	9,068	17,360	-	9,068	9,068	$ 4.370	$ 39,627
Jan-23	1/25/2023	7,749	8,417	16,166	-	8,417	8,417	$ 3.835	$ 32,279
Jan-23	1/26/2023	8,337	8,684	17,021	-	8,684	8,684	$ 4.225	$ 36,690

Load Shape Price Factor Worksheet

Month	Date	Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
		Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Jan-23	1/27/2023	8,052	8,363	16,415	-	8,363	8,363	$ 3.270	$ 27,347
Jan-23	1/28/2023	7,147	7,202	14,349	-	7,202	7,202	$ 3.215	$ 23,154
Jan-23	1/29/2023	6,427	7,592	14,019	-	7,592	7,592	$ 3.215	$ 24,408
Jan-23	1/30/2023	7,935	8,192	16,127	-	8,192	8,192	$ 3.215	$ 26,337
Jan-23	1/31/2023	10,210	9,643	19,853	-	9,643	9,643	$ 12.025	$ 115,957
Feb-23	2/1/2023	9,823	9,440	19,263	-	9,440	9,440	$ 13.605	$ 128,431
Feb-23	2/2/2023	9,334	8,988	18,322	-	8,988	8,988	$ 12.155	$ 109,249
Feb-23	2/3/2023	15,400	8,690	24,090	-	8,690	8,690	$ 66.370	$ 576,755
Feb-23	2/4/2023	11,219	9,238	20,457	-	9,238	9,238	$ 9.015	$ 83,281
Feb-23	2/5/2023	6,663	7,997	14,660	-	7,997	7,997	$ 9.015	$ 72,093
Feb-23	2/6/2023	8,447	8,570	17,017	-	8,570	8,570	$ 9.015	$ 77,259
Feb-23	2/7/2023	8,599	8,567	17,166	-	8,567	8,567	$ 3.175	$ 27,200
Feb-23	2/8/2023	7,888	8,449	16,337	-	8,449	8,449	$ 2.860	$ 24,164
Feb-23	2/9/2023	7,115	7,231	14,346	-	7,231	7,231	$ 2.520	$ 18,222
Feb-23	2/10/2023	6,407	7,114	13,521	-	7,114	7,114	$ 2.325	$ 16,540
Feb-23	2/11/2023	7,354	6,779	14,133	-	6,779	6,779	$ 2.755	$ 18,676
Feb-23	2/12/2023	6,912	6,144	13,056	-	6,144	6,144	$ 2.755	$ 16,927
Feb-23	2/13/2023	7,633	7,024	14,657	-	7,024	7,024	$ 2.755	$ 19,351
Feb-23	2/14/2023	7,919	8,256	16,175	-	8,256	8,256	$ 2.590	$ 21,383
Feb-23	2/15/2023	5,388	6,931	12,319	-	6,931	6,931	$ 2.100	$ 14,555
Feb-23	2/16/2023	5,521	6,664	12,185	-	6,664	6,664	$ 2.130	$ 14,194
Feb-23	2/17/2023	8,368	8,296	16,664	-	8,296	8,296	$ 2.740	$ 22,731
Feb-23	2/18/2023	7,713	8,132	15,845	-	8,132	8,132	$ 2.580	$ 20,981
Feb-23	2/19/2023	6,867	7,471	14,338	-	7,471	7,471	$ 2.580	$ 19,275
Feb-23	2/20/2023	6,435	7,110	13,545	-	7,110	7,110	$ 2.580	$ 18,344
Feb-23	2/21/2023	7,972	8,492	16,464	-	8,492	8,492	$ 2.580	$ 21,909
Feb-23	2/22/2023	8,351	8,775	17,126	-	8,775	8,775	$ 2.285	$ 20,051
Feb-23	2/23/2023	10,199	9,125	19,324	-	9,125	9,125	$ 4.380	$ 39,968
Feb-23	2/24/2023	11,049	9,608	20,657	-	9,608	9,608	$ 15.445	$ 148,396

Load Shape Price Factor Worksheet

Month	Date	Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
		Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Feb-23	2/25/2023	10,697	9,560	20,257	-	9,560	9,560	$ 12.285	$ 117,445
Feb-23	2/26/2023	10,515	9,548	20,063	-	9,548	9,548	$ 12.285	$ 117,297
Feb-23	2/27/2023	9,052	8,461	17,513	-	8,461	8,461	$ 12.285	$ 103,943
Feb-23	2/28/2023	8,318	7,857	16,175	-	7,857	7,857	$ 7.160	$ 56,256
Mar-23	3/1/2023	7,499	6,801	14,300	-	6,801	6,801	$ 3.140	$ 21,355
Mar-23	3/2/2023	7,914	7,407	15,321	-	7,407	7,407	$ 3.260	$ 24,147
Mar-23	3/3/2023	7,195	6,714	13,909	-	6,714	6,714	$ 4.010	$ 26,923
Mar-23	3/4/2023	7,881	6,540	14,421	-	6,540	6,540	$ 4.160	$ 27,206
Mar-23	3/5/2023	7,161	6,015	13,176	-	6,015	6,015	$ 4.160	$ 25,022
Mar-23	3/6/2023	7,845	6,921	14,766	-	6,921	6,921	$ 4.160	$ 28,791
Mar-23	3/7/2023	8,477	8,304	16,781	-	8,304	8,304	$ 6.145	$ 51,028
Mar-23	3/8/2023	7,334	7,442	14,776	-	7,442	7,442	$ 3.360	$ 25,005
Mar-23	3/9/2023	7,527	7,314	14,841	-	7,314	7,314	$ 2.970	$ 21,723
Mar-23	3/10/2023	6,845	6,986	13,831	-	6,986	6,986	$ 2.770	$ 19,351
Mar-23	3/11/2023	7,439	7,242	14,681	-	7,242	7,242	$ 2.790	$ 20,205
Mar-23	3/12/2023	7,198	7,615	14,813	-	7,615	7,615	$ 2.790	$ 21,246
Mar-23	3/13/2023	7,342	8,238	15,580	-	8,238	8,238	$ 2.790	$ 22,984
Mar-23	3/14/2023	8,249	9,079	17,328	-	9,079	9,079	$ 4.235	$ 38,450
Mar-23	3/15/2023	8,086	8,562	16,648	-	8,562	8,562	$ 3.015	$ 25,814
Mar-23	3/16/2023	7,187	7,938	15,125	-	7,938	7,938	$ 2.505	$ 19,885
Mar-23	3/17/2023	6,487	7,896	14,383	-	7,896	7,896	$ 2.350	$ 18,556
Mar-23	3/18/2023	6,260	7,284	13,544	-	7,284	7,284	$ 3.200	$ 23,309
Mar-23	3/19/2023	8,366	8,216	16,582	-	8,216	8,216	$ 3.200	$ 26,291
Mar-23	3/20/2023	7,058	8,184	15,242	-	8,184	8,184	$ 3.200	$ 26,189
Mar-23	3/21/2023	6,088	7,994	14,082	-	7,994	7,994	$ 2.205	$ 17,627
Mar-23	3/22/2023	6,419	7,613	14,032	-	7,613	7,613	$ 2.005	$ 15,264
Mar-23	3/23/2023	5,950	7,108	13,058	-	7,108	7,108	$ 2.020	$ 14,358
Mar-23	3/24/2023	6,819	7,984	14,803	-	7,984	7,984	$ 2.045	$ 16,327
Mar-23	3/25/2023	6,721	7,457	14,178	-	7,457	7,457	$ 1.945	$ 14,504

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
Month	Date	Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Mar-23	3/26/2023	6,128	7,450	13,578	-	7,450	7,450	$ 1.945	$ 14,490
Mar-23	3/27/2023	6,209	7,494	13,703	-	7,494	7,494	$ 1.945	$ 14,576
Mar-23	3/28/2023	7,400	8,632	16,032	-	8,632	8,632	$ 2.180	$ 18,818
Mar-23	3/29/2023	7,069	7,834	14,903	-	7,834	7,834	$ 2.150	$ 16,843
Mar-23	3/30/2023	8,079	8,956	17,035	-	8,956	8,956	$ 2.535	$ 22,703
Mar-23	3/31/2023	6,349	7,695	14,044	-	7,695	7,695	$ 2.060	$ 15,852
Apr-23	4/1/2023	5,406	6,584	11,990	-	6,584	6,584	$ 2.050	$ 13,497
Apr-23	4/2/2023	7,266	7,787	15,053	-	7,787	7,787	$ 2.050	$ 15,963
Apr-23	4/3/2023	5,642	7,165	12,807	-	7,165	7,165	$ 2.050	$ 14,688
Apr-23	4/4/2023	5,491	7,404	12,895	-	7,404	7,404	$ 2.125	$ 15,734
Apr-23	4/5/2023	7,346	8,275	15,621	-	8,275	8,275	$ 2.085	$ 17,253
Apr-23	4/6/2023	5,413	7,355	12,768	-	7,355	7,355	$ 2.040	$ 15,004
Apr-23	4/7/2023	6,611	7,440	14,051	-	7,440	7,440	$ 2.100	$ 15,624
Apr-23	4/8/2023	6,410	7,270	13,680	-	7,270	7,270	$ 2.100	$ 15,267
Apr-23	4/9/2023	6,013	6,792	12,805	-	6,792	6,792	$ 2.100	$ 14,263
Apr-23	4/10/2023	5,172	6,981	12,153	-	6,981	6,981	$ 2.100	$ 14,660
Apr-23	4/11/2023	3,340	6,807	10,147	-	6,807	6,807	$ 1.750	$ 11,912
Apr-23	4/12/2023	4,161	6,861	11,022	-	6,861	6,861	$ 1.715	$ 11,767
Apr-23	4/13/2023	3,221	6,782	10,003	-	6,782	6,782	$ 1.720	$ 11,665
Apr-23	4/14/2023	3,981	5,960	9,941	-	5,960	5,960	$ 1.455	$ 8,672
Apr-23	4/15/2023	4,488	5,654	10,142	-	5,654	5,654	$ 1.425	$ 8,057
Apr-23	4/16/2023	4,889	5,971	10,860	-	5,971	5,971	$ 1.425	$ 8,509
Apr-23	4/17/2023	5,686	6,662	12,348	-	6,662	6,662	$ 1.425	$ 9,493
Apr-23	4/18/2023	5,475	8,080	13,555	-	8,080	8,080	$ 2.115	$ 17,089
Apr-23	4/19/2023	5,973	8,120	14,093	-	8,120	8,120	$ 2.065	$ 16,768
Apr-23	4/20/2023	5,568	7,333	12,901	-	7,333	7,333	$ 2.010	$ 14,739
Apr-23	4/21/2023	5,730	7,082	12,812	-	7,082	7,082	$ 1.775	$ 12,571
Apr-23	4/22/2023	5,172	6,713	11,885	-	6,713	6,713	$ 1.770	$ 11,882
Apr-23	4/23/2023	5,573	7,187	12,760	-	7,187	7,187	$ 1.770	$ 12,721

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2022-2023 Cost Analysis	
Month	Date	Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total	AGT City-Gate Price	AGT City-Gate Cost
Apr-23	4/24/2023	5,602	7,692	13,294	-	7,692	7,692	$ 1.770	$ 13,615
Apr-23	4/25/2023	5,698	8,169	13,867	-	8,169	8,169	$ 2.325	$ 18,993
Apr-23	4/26/2023	6,109	8,169	14,278	-	8,169	8,169	$ 2.325	$ 18,993
Apr-23	4/27/2023	5,485	7,898	13,383	-	7,898	7,898	$ 2.160	$ 17,060
Apr-23	4/28/2023	4,595	7,190	11,785	-	7,190	7,190	$ 1.720	$ 12,367
Apr-23	4/29/2023	5,059	6,585	11,644	-	6,585	6,585	$ 1.720	$ 11,326
Apr-23	4/30/2023	4,982	6,357	11,339	-	6,357	6,357	$ 1.720	$ 10,934
Winter Period		1,268,380	1,389,388	2,657,768	-	1,389,388	1,389,388	$ 6.391	$ 8,880,076

Weighted Average Daily Price	$ 6.391
Straight Average Daily Price	$ 6.204
Load Shape Price Factor	1.030

Month	Projected Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment		
	Capacity Assigned	Capacity Exempt	Total	Capacity Assigned	Capacity Exempt	Total
Nov-23	204,739	215,092	419,831	-	215,092	215,092
Dec-23	230,871	225,487	456,358	-	225,487	225,487
Jan-24	256,133	244,130	500,263	-	244,130	244,130
Feb-24	237,436	229,129	466,565	-	229,129	229,129
Mar-24	235,381	225,467	460,848	-	225,467	225,467
Apr-24	197,347	215,177	412,524	-	215,177	215,177
Winter	1,361,907	1,354,482	2,716,389	-	1,354,482	1,354,482

REDACTED

Rank	Estimated Delivered City-Gate Commodity Costs and Volumes November 2023 through April 2024 Denotes Confidential Information			
Rank	Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
1	Tennessee FS-MA Storage Path	[redacted]	384,490	[redacted]
2	Empress Proposed Pipeline Path	[redacted]	292,979	[redacted]
3	Union Dawn Storage Path	[redacted]	4,393,622	[redacted]
4	Tennessee Niagara Pipeline Path	[redacted]	322,826	[redacted]
5	Algonquin Receipts Pipeline Path	[redacted]	190,152	[redacted]
6	Tennessee Long-Haul Pipeline Path	[redacted]	1,213,649	[redacted]
7	Atlantic Bridge Ramapo Pipeline Path	[redacted]	1,041,040	[redacted]
8	Iroquois Receipts Pipeline Path	[redacted]	947,681	[redacted]
9	Peaking Contract 1	[redacted]	599,888	[redacted]
10	Lewiston LNG	[redacted]	10,920	[redacted]
	Total Delivered Commodity Cost	$49,212,770	9,397,248	$5.237

REDACTED

Rank	Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
	Estimated Delivered City-Gate Commodity Costs and Volumes May 2024 through October 2024 Denotes Confidential Information			
1	TGP Zone 4 300 Leg Supply	[redacted]	209,998	[redacted]
2	Atlantic Bridge Ramapo Pipeline Path	[redacted]	717,025	[redacted]
3	Empress Proposed Pipeline Path	[redacted]	1,371,796	[redacted]
4	Tennessee Niagara Pipeline Path	[redacted]	51,464	[redacted]
5	Dawn Supply	[redacted]	83,633	[redacted]
6	Lewiston LNG	[redacted]	11,040	[redacted]
	Total Delivered Commodity Cost	$6,088,689	2,444,956	$2.490

Northern Utilities, Inc.
Normal Year Weather - Sales Load and Company-Managed Sales
Commodity Volumes by Supply Source (Dth)
November 2023 through October 2024

Description	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Winter
Pipeline Supplies													
Tennessee Long-Haul Pipeline Path	149,475	309,904	309,904	289,910	154,458	0	0	0	0	0	0	0	1,213,649
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	36,279	38,781	0	0	0	0	0	0	0	190,152
Iroquois Receipts Pipeline Path	187,042	193,277	193,277	180,808	193,277	0	0	0	0	0	0	0	947,681
Tennessee Niagara Pipeline Path	53,213	54,987	54,987	51,439	54,987	53,213	21,455	0	0	0	1,716	28,293	322,826
Atlantic Bridge Ramapo Pipeline Path	171,600	177,320	177,320	165,880	177,320	171,600	177,320	171,600	0	19,185	171,600	177,320	1,041,040
Empress Proposed Pipeline Path	0	0	0	0	0	292,979	201,028	171,909	303,562	303,562	110,318	281,416	292,979
Subtotal Pipeline	598,860	774,269	774,269	724,316	618,822	517,792	399,803	343,509	303,562	322,747	283,635	487,028	4,008,328
Underground Storage													
Tennessee Storage	0	12,413	65,490	61,265	65,044	0	0	0	0	0	0	0	204,212
TGP Zone 4 300 Leg Supply	63,377	53,077	0	0	446	63,377	65,490	0	15,641	0	63,377	65,490	180,278
Tennessee FS-MA Storage Path	63,377	65,490	65,490	61,265	65,490	63,377	65,490	0	15,641	0	63,377	65,490	384,490
Union Dawn Storage	0	824,114	916,157	868,904	803,660	0	0	0	0	0	0	0	3,412,835
Dawn Supply	593,326	0	0	0	0	387,461	42,583	0	0	0	0	41,051	980,787
Union Dawn Storage Path	593,326	824,114	916,157	868,904	803,660	387,461	42,583	0	0	0	0	41,051	4,393,622
Subtotal Storage	656,704	889,604	981,647	930,169	869,150	450,839	108,073	0	15,641	0	63,377	106,541	4,778,112
Peaking Supplies													
Lewiston LNG	1,800	1,860	1,860	1,740	1,860	1,800	1,860	1,800	1,860	1,860	1,800	1,860	10,920
PNGTS Delivered (Dec - Feb)	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Contract 1	0	89,707	285,716	131,938	92,527	0	0	0	0	0	0	0	599,888
Peaking Contract 2	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental Delivered Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Peaking	1,800	91,567	287,576	133,678	94,387	1,800	1,860	1,800	1,860	1,860	1,800	1,860	610,808
Total Delivered (Dth)	1,257,364	1,755,439	2,043,492	1,788,162	1,582,360	970,431	509,736	345,309	321,063	324,607	348,812	595,429	9,397,248

Northern Utilities, Inc.
Design Year Weather - Planning Load
Commodity Volumes by Supply Source (Dth)
November 2023 through October 2024

Description	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Winter
Pipeline Supplies													
Tennessee Long-Haul Pipeline Path	149,475	406,378	406,378	380,160	154,458	0	0	0	0	0	0	0	1,496,848
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	36,279	38,781	0	0	0	0	0	0	0	190,152
Iroquois Receipts Pipeline Path	193,021	199,455	199,455	186,587	199,455	0	0	0	0	0	0	0	977,975
Tennessee Niagara Pipeline Path	69,805	72,132	72,132	67,478	72,132	69,805	37,218	0	0	0	4,892	60,500	423,483
Atlantic Bridge Ramapo Pipeline Path	225,000	232,500	232,500	217,500	232,500	225,000	232,500	225,000	0	52,783	225,000	232,500	1,365,000
Empress Proposed Pipeline Path	0	0	0	0	0	384,161	293,153	278,199	398,059	398,059	209,173	394,489	384,161
Subtotal Pipeline	674,831	949,246	949,246	888,004	697,326	678,966	562,871	503,199	398,059	450,842	439,065	687,489	4,837,618
Underground Storage													
Tennessee Storage	0	15,496	81,955	76,668	81,390	0	0	0	0	0	0	0	255,509
TGP Zone 4 300 Leg Supply	79,311	66,459	0	0	565	79,311	81,955	87	47,668	0	79,311	81,955	225,647
Tennessee FS-MA Storage Path	79,311	81,955	81,955	76,668	81,955	79,311	81,955	87	47,668	0	79,311	81,955	481,156
Union Dawn Storage	0	1,369,533	1,580,214	1,519,808	1,282,612	0	0	0	0	0	0	0	5,752,167
Dawn Supply	938,366	18,736	0	0	0	469,068	99,745	0	0	0	5,898	145,879	1,426,169
Union Dawn Storage Path	938,366	1,388,269	1,580,214	1,519,808	1,282,612	469,068	99,745	0	0	0	5,898	145,879	7,178,337
Subtotal Storage	1,017,677	1,470,224	1,662,169	1,596,476	1,364,567	548,380	181,700	87	47,668	0	85,209	227,834	7,659,493
Peaking Supplies													
Lewiston LNG	1,800	1,860	11,545	1,740	1,860	1,800	1,860	1,800	1,860	1,860	1,800	1,860	20,605
PNGTS Delivered (Dec - Feb)	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Contract 1	0	52,098	232,997	138,118	176,675	0	0	0	0	0	0	0	599,889
Peaking Contract 2	0	0	569	0	0	0	0	0	0	0	0	0	569
Incremental Delivered Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Peaking	1,800	53,958	245,111	139,858	178,535	1,800	1,860	1,800	1,860	1,860	1,800	1,860	621,063
Total Delivered (Dth)	1,694,308	2,473,428	2,856,526	2,624,338	2,240,428	1,229,146	746,432	505,086	447,587	452,702	526,074	917,183	13,118,174

Northern Utilities, Inc.
Normal Year Weather - Sales Load and Company-Managed Sales
Capacity Utilization by Supply Source
November 2023 through October 2024

Description	Winter Projected Volume (Dth)	Winter Maximum Volume (Dth)	Winter Capacity Utilization	Summer Projected Volume (Dth)	Summer Maximum Volume (Dth)	Summer Capacity Utilization	Annual Projected Volume (Dth)	Annual Maximum Volume (Dth)	Annual Capacity Utilization
Pipeline Supplies									
Tennessee Long-Haul Pipeline Path	1,213,649	1,819,434	67%	0	1,839,427	0%	1,213,649	3,658,861	33%
Algonquin Receipts Pipeline Path	190,152	227,682	84%	0	230,184	0%	190,152	457,866	42%
Iroquois Receipts Pipeline Path	947,681	1,134,724	84%	0	1,147,193	0%	947,681	2,281,917	42%
Tennessee Niagara Pipeline Path	322,826	322,826	100%	51,464	326,374	16%	374,290	649,200	58%
Atlantic Bridge Ramapo Pipeline Path	1,041,040	1,041,040	100%	717,025	1,052,480	68%	1,758,065	2,093,520	84%
Empress Proposed Pipeline Path	292,979	284,989	103%	1,371,796	1,747,933	78%	1,664,775	2,032,922	82%
Subtotal Pipeline	4,008,328	4,830,695	83%	2,140,285	6,343,591	34%	6,148,613	11,174,286	55%
Underground Storage									
Tennessee Storage	204,212			0			204,212		
TGP Zone 4 300 Leg Supply	180,278			209,998			390,276		
Tennessee FS-MA Storage Path	384,490	384,490	100%	209,998	388,715	54%	594,488	773,204	77%
Union Dawn Storage	3,412,835			0			3,412,835		
Dawn Supply	980,787			83,633			1,064,420		
Union Dawn Storage Path	4,393,622	8,697,444	51%	83,633	8,793,020	1%	4,477,256	17,490,464	26%
Subtotal Storage	4,778,112	9,081,934	53%	293,631	9,181,735	3%	5,071,743	18,263,669	28%
Peaking Supplies									
Lewiston LNG	10,920	62,160	18%	11,040	11,040	100%	21,960	73,200	30%
PNGTS Delivered (Dec - Feb)	0	0		0	0		0	0	
Peaking Contract 1	599,888	597,900	100%	0	0		599,888	597,900	
Peaking Contract 2	0	0		0	0		0	0	
Subtotal Peaking	610,808	660,060	93%	11,040	11,040	100%	621,848	671,100	93%
Portfolio Utilization	9,397,248	14,572,688	64%	2,444,956	15,536,366	16%	11,842,204	30,109,054	39%
Incremental Delivered Supplies	0	N/A		0	N/A		0	N/A	
Total Delivered	9,397,248	N/A		2,444,956	N/A		11,842,204	N/A	

Northern Utilities, Inc.
Design Year Weather - Planning Load
Capacity Utilization by Supply Source
November 2023 through October 2024

Description	Winter Projected Volume (Dth)	Winter Maximum Volume (Dth)	Winter Capacity Utilization	Summer Projected Volume (Dth)	Summer Maximum Volume (Dth)	Summer Capacity Utilization	Annual Projected Volume (Dth)	Annual Maximum Volume (Dth)	Annual Capacity Utilization
Pipeline Supplies									
Tennessee Long-Haul Pipeline Path	1,496,848	2,385,830	63%	0	2,412,048	0%	1,496,848	4,797,878	31%
Algonquin Receipts Pipeline Path	190,152	227,682	84%	0	230,184	0%	190,152	457,866	42%
Iroquois Receipts Pipeline Path	977,975	1,170,996	84%	0	1,183,864	0%	977,975	2,354,861	42%
Tennessee Niagara Pipeline Path	423,483	423,483	100%	102,610	428,136	24%	526,093	851,619	62%
Atlantic Bridge Ramapo Pipeline Path	1,365,000	1,365,000	100%	967,783	1,380,000	70%	2,332,783	2,745,000	85%
Empress Proposed Pipeline Path	384,161	373,688	103%	1,971,133	2,291,950	86%	2,355,294	2,665,638	88%
Subtotal Pipeline	4,837,618	5,946,679	81%	3,041,526	7,926,183	38%	7,879,144	13,872,862	57%
Underground Storage									
Tennessee Storage	255,509			0			255,509		
TGP Zone 4 300 Leg Supply	225,647			290,977			516,624		
Tennessee FS-MA Storage Path	481,156	481,156	100%	290,977	486,443	60%	772,133	967,600	80%
Union Dawn Storage	5,752,167			0			5,752,167		
Dawn Supply	1,426,169			251,521			1,677,691		
Union Dawn Storage Path	7,178,337	10,882,324	66%	251,521	11,001,910	2%	7,429,858	21,884,234	34%
Subtotal Storage	7,659,493	11,363,480	67%	542,498	11,488,354	5%	8,201,991	22,851,834	36%
Peaking Supplies									
Lewiston LNG	20,605	62,160	33%	11,040	11,040	100%	31,645	73,200	43%
PNGTS Delivered (Dec - Feb)	0	0		0	0		0	0	
Peaking Contract 1	599,889	597,900	100%	0	0		599,889	597,900	
Peaking Contract 2	569	569	100%	0	0		569	569	
Subtotal Peaking	621,063	660,629	94%	11,040	11,040	100%	632,103	671,669	94%
Portfolio Utilization	13,118,174	17,970,788	73%	3,595,064	19,425,576	19%	16,713,238	37,396,364	45%
Incremental Delivered Supplies	0	N/A		0	N/A		0	N/A	
Total Delivered	13,118,174	N/A		3,595,064	N/A		16,713,238	N/A	

Northern Utilities Inc.
Forecast of Upcoming Winter Period Design Day Report
2023 / 2024 Winter Period
(Therms)

Demand	
NH Firm Sales	460,040
NH Non-Capacity Exempt Transportation	145,450
NH Capacity Exempt Transportation	97,080
NH Interruptible Sales	0
NH Interruptible Transportation	0
NH Design Day Demand	702,560
ME Firm Sales	687,700
ME Non-Capacity Exempt Transportation	156,430
ME Capacity Exempt Transportation	102,130
ME Interruptible Sales	0
ME Interruptible Transportation	0
ME Design Day Demand	946,250
Total Firm Sales	1,147,740
Total Non-Capacity Exempt Transportation	301,880
Total Capacity Exempt Transportation	199,210
Total Interruptible Sales	0
Total Interruptible Transportation	0
Total Design Day Demand	1,648,830
Supplies	
Capacity Exempt Transportation	199,210
Additional Supplies Required for Non-Capacity Exempt Transport	118,900
Pipeline	306,210
Storage	624,370
On-System LNG	65,000
Off-System Peaking Contracts & Delivered Baseload	398,600
Additional Granite Capacity	34,260
Total	1,746,550

Effective Degree Day	
New Hampshire	80.1
Maine	78.7
Probability	1 in 30

Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	Francis X. Wells

Northern Utilities Inc.
New Hampshire 7 Day Cold Snap Analysis
Winter 2023-2024

Coldest 7 Consecutive Days
Based on historic Portsmouth weather data

Date	EDD
February 11, 1979	68
February 12, 1979	60
February 13, 1979	73
February 14, 1979	73
February 15, 1979	64
February 16, 1979	69
February 17, 1979	72
Total	479

Maximum Projected Design Week Demand (Dth)

Daily Baseload	6,940
Weekly Baseload	48,583
Heating Increment*	604
Effective Degree Days	479
Total Heat Load	289,429
Projected Cold Snap Demand	338,012

New Hampshire Allocation **40.06%**
Based on the latest demand cost allocator in the Winter COG filing.

Maximum Supply Capability (Dth)

Amount to be Supplied by Natural Gas Pipelines	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
Atlantic Bridge Ramapo	7,500
Tennessee Firm Storage	2,644
Union Dawn Storage	59,793
Peaking Contract 1	29,895
Peaking Contract 2	9,965
Total Daily Pipeline	132,918
Pipeline for 7 days	930,426
New Hampshire Allocation	372,729

Available LNG Storage

Facility	Gallons	Dth
Lewiston LNG	145,134	12,140
Total	145,134	12,140
New Hampshire Allocation - 7 Days		4,863

LNG Delivery Contract

Northern Utilities plans to secure a contract for LNG Delivery for up to three loads of LNG per day.

The storage credit for LNG is calculated as follows:

Number of Days	7
Number of Loads	3
Delivery Reliability	70%
Assumed Number of LNG Deliveries	15
Dth Per Load	900
Total Storage Credit	13,230
NH Storage Credit - 7 Days	5,300

Summary	
Maximum projected design week demand	338,012
Amount to be furnished by natural gas pipeline	372,729
Remaining Balance	-34,717
Storage available	4,863
Credit from LNG delivery supply contract	5,300
Total available storage and LNG deliveries	10,163
Net Surplus/(Deficiency)	**44,880**

Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	Fran X Wells

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2023 through October 2024

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	892,796	42%	84%
G50	139,554	7%	80%
G41	597,290	28%	43%
G51	214,887	10%	43%
G42	189,700	9%	37%
G52	79,674	4%	4%
Special Contracts	-	0%	0%
Total C&I	2,113,901	100%	32%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
G40	171,278	4%	16%
G50	35,654	1%	20%
G41	777,083	17%	57%
G51	287,066	6%	57%
G42	323,201	7%	63%
G52	1,742,448	39%	96%
Special Contracts	1,178,205	26%	100%
Total C&I	4,514,935	100%	68%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G40	1,064,075	16%
G50	175,208	3%
G41	1,374,373	21%
G51	501,953	8%
G42	512,900	8%
G52	1,822,122	27%
Special Contracts	1,178,205	18%
Total C&I	6,628,836	100%