NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2024-2025
COST OF GAS FILING

PREFILED TESTIMONY OF
FRANCIS X. WELLS

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 2024-2025 fixed, annual demand cost estimates are 31% higher than the fixed, annual demand cost estimates provided for the prior 2023-2024 Winter Period CGF filing. Most of this increase is attributable to higher peaking supply demand costs. Higher peaking supply demand costs are offset by lower peaking supply commodity costs, as I will discuss further below. Another contributing factor to this increase is the inclusion of a full year of Empress Capacity costs. The 2023-2024 annual demand cost budget included 7 months of Empress Capacity costs, as these contracts commenced on April 1, 2024. The 2024-2025 annual demand cost budget includes these contracts for the full 12 months.

Estimated average delivered commodity rates for the 2024-2025 Winter Period are 47% lower than the average delivered commodity rates estimated for the 2023-2024 Winter Period COG. The largest factor contributing to this decrease is lower delivered peaking supply unit costs and volumes. Other contributing factors are lower NYMEX natural gas futures prices, lower projected pipeline supply rates due to the availability of new Empress supply, and lower projected storage inventory costs for the upcoming 2024-2025 Winter Period, relative to that which was projected for 2023-2024.

Estimated average delivery commodity rates for the 2025 Summer Period are 19% lower than the average delivered commodity rates estimated for the 2024 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 8,941,804 Dth in the New Hampshire Division for the 2024-2025 Annual Period, which is 4.0% higher than the projected 2023-2024 Annual Period weather-normalized distribution deliveries and 6.2% higher than the 2022-2023 Annual Period weather-normalized distribution deliveries. Of the 8,941,804 Dth of projected distribution system deliveries, Northern projects that 4,133,153 Dth will be supplied by the Company through Sales Service. In order to supply 4,133,153 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,143,928 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 129,412 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,273,340 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 Northern's New Hampshire Division Delivery Service Terms and Conditions). Including delivered peaking supply contracts, which are not assignable under the Delivery Service Terms and Conditions, Northern's portfolio can delivery up to 146,906 Dth per day. 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 2023-2024 Annual Period COG Filing, including Northern's implementation of its Price Risk Mitigation Plan. I also provide an update on Northern's precedent agreement with TransCanada related to the construction of permanent facilities needed to provide service to Northern for its new Empress Capacity Path.

I project Northern's total company (including both the Maine and New Hampshire Divisions) demand cost for the November 2024 through October 2025 gas year to be $48,743,245. (*See* Attachment NUI-FXW-5). Mr. Christopher A. 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 $6,473,567. (*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 2024-2025 Winter Period will be $24,287,516 at an average rate equal to $2.709 per Dth. (*See* Attachment NUI-FXW-8). 2024 Summer Period commodity cost to provide sales service are projected to be $5,345,048 at an average rate equal to $2.007 per Dth.

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.

Finally, I will provide a report on available price hedging strategies in compliance with the Settlement Agreement between the New Hampshire Department of Energy ("NH DOE") and Northern, which was approved by the Commission in Docket No. DG 23-087.

II. SALES AND SENDOUT FORECAST

Q. Please describe the Company's forecasts sales.

A. Company sales forecasts are derived from historical data of average monthly meter counts and the respective monthly usage per meter. Each rate class is separated between sales service and delivery service after which econometric regression models are developed for each data set. These regression models use independent variables gathered from Moody's analytics for the Rockingham and Strafford county areas (such as gross metropolitan product, unemployment rates, consumer price index, etc) when and if possible. Each regression minimizes autocorrelation within 12 lags and works towards limiting heteroskedasticity, while maintaining high R-squared values and reasonable forecasting results. The forecasts are typically driven either by trends, demographic/econometric variables, and/or weather normal forecasts. Note that weather normal forecasts were derived by averaging the actual effective degree days for each month over the last 15 years.

Q. Has the forecast process changed from prior Cost of Gas filings?

A. Yes. In prior COG filings, an econometric model for distribution deliveries was developed for each rate class and then historic sales were used to allocate that forecast between Sales Service and Delivery Service. As discussed above, the Company has since developed models for Sales and Delivery Service sales and meter count data separately, which is the process used in the instant filing.

Q. Please provide the forecast of 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 2024-2025 Annual Period.

Table 1. 2024-2025 Annual New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years							
Month	2024-2025 Forecast	2023-2024 Weather-Normalized Actual	2024-2025 minus 2023-2024	Percent Change	2022-2023 Weather-Normalized Actual	2024-2025 minus 2022-2023	Percent Change
Nov	702,581	713,433	-10,852	-1.5%	650,385	52,196	8.0%
Dec	1,002,653	965,725	36,928	3.8%	937,298	65,355	7.0%
Jan	1,256,448	1,192,314	64,134	5.4%	1,234,771	21,677	1.8%
Feb	1,276,817	1,287,374	-10,557	-0.8%	1,243,275	33,542	2.7%
Mar	1,150,131	1,092,124	58,007	5.3%	1,087,759	62,371	5.7%
Apr	817,426	642,565	174,861	27.2%	768,088	49,337	6.4%
May	611,851	604,779	7,072	1.2%	551,913	59,938	10.9%
Jun	435,956	430,744	5,212	1.2%	399,715	36,242	9.1%
Jul	400,146	395,493	4,653	1.2%	358,153	41,993	11.7%
Aug	401,216	396,621	4,595	1.2%	374,356	26,860	7.2%
Sep	397,113	392,576	4,537	1.2%	360,925	36,188	10.0%
Oct	489,467	484,221	5,245	1.1%	450,815	38,652	8.6%
Winter	6,206,054	5,893,534	312,521	5.3%	5,921,575	284,479	4.8%
Summer	2,735,750	2,704,436	31,315	1.2%	2,495,877	239,873	9.6%
Annual	8,941,804	8,597,969	343,835	4.0%	8,417,452	524,352	6.2%

The forecast of distribution deliveries is projected to increase 4.0% compared to the 2023-2024 weather-normalized actual sales. Page 1 of Attachment NUI-FXW-1 shows that the increase in sales is explained by a 1.5% projected increase in meter counts and a 2.5% 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 2024-2025 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 2024-2025 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2023-2024 and 2022-2023 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. 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.

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-24	890,286	437,673	23,220	462,034
Dec-24	1,121,623	640,219	26,142	668,030
Jan-25	1,267,826	745,414	31,745	779,103
Feb-25	1,134,080	647,542	23,319	672,549
Mar-25	1,043,951	550,000	24,986	576,420
Apr-25	748,288	314,387	0	315,206
May-25	515,313	172,044	0	172,492
Jun-25	420,315	111,335	0	111,625
Jul-25	399,758	95,129	0	95,377
Aug-25	412,135	96,179	0	96,430
Sep-25	421,831	107,300	0	107,580
Oct-25	566,398	215,931	0	216,494
Winter	6,206,054	3,335,235	129,412	3,473,342
Summer	2,735,750	797,918	0	799,998
Annual	8,941,804	4,133,153	129,412	4,273,340

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

[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.

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 EGMA 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[2]. 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.

[2] Off-system peaking supply contracts, such as Peaking Contract 1 and Peaking Contract 2 are not assigned to retail marketers, pursuant to Northern's Delivery Service Terms and Conditions. Northern considers only its projected Sales Service requirements when entering off-system peaking supply transactions.

III. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio.

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 Eversource Gas Company of Massachusetts d/b/a Eversource Energy ("EGMA").

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
Empress	12,456
Total Pipeline Capacity	43,077
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	24,913
Peaking Contract 2 - Lewiston	4,062
Peaking Contract 2 - via Granite	5,917
Total Peaking Capacity	41,392
Total Design Day Capacity	146,906

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2024-2025 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above.

Subsequent pages of Attachment NUI-FXW-4 include capacity path diagram and capacity path detail 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")[3], 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 has entered two five-year peaking contracts, Peaking Contract 1 and Peaking Contract 2, which will provide off-system peaking supply for the 2024-2025 through 2028-2029 Winter Periods. Each contract was procured via an RFP process that concluded in February 2024. 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. Northern has entered a five-year LNG Contract for up to 3,000 Dth per day with an annual contract quantity of up to 75,000 Dth beginning June 2024, which will provide LNG supply for the Lewiston facility through March 31, 2029. The gas supply portfolio includes an exchange agreement with EGMA ("EGMA Exchange" or "EGMA Exchange Agreement"), which is needed to bring the Iroquois Receipts, Leidy Hub Supply and

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

Transco Zone 6, non-NY capacity path supplies into Northern's system, as the delivery points on these capacity paths are on the EGMA 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, in order 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 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, 2024 through March 31, 2025. Northern has entered into asset management agreements for the Atlantic Bridge Ramapo, Iroquois Receipts, Algonquin Receipts, Niagara, Tennessee Zone 0/L, Empress, and Dawn Hub Storage capacity paths. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for Off-System Peaking and LNG supplies for the upcoming winter.

Q. Please describe any changes in Northern's portfolio for the upcoming 2024-2025 Annual Period compared to the portfolio relied upon for the 2023-2024 Annual Period.

A. The following changes have been made to Northern's portfolio for the 2024-2025 Winter Period.

1. The Empress Capacity Path, which commenced April 1, 2024, will be available for the full Winter Period. Contracts with TCPL and PNGTS 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.

2. Both Peaking Contract 1 and Peaking Contract 2 are five-year off-system peaking supply contacts that have been added to the portfolio this year.

   Peaking Contract 1 provides up to 25,000 Dth per Day and 500,000 Dth annually from November through March for five winter periods beginning 2024-2025 through 2028-2029. Northern is not required to take any portion of this peaking supply contract. This replaces a peaking supply contract in the 2023-2024 portfolio of up to 30,000 Dth per Day and 600,000 Dth from November through March, which required Northern to utilize all 600,000 Dth.

   Peaking Contract 2 provides up to 10,000 Dth per Day and up to 50,000 Dth annually from November through March from November through March for five winter periods beginning 2024-2025 through 2028-2029. Northern is not required to take any portion of this peaking supply contract. This replaces a peaking supply contract in the 2023-2024 portfolio of the same volumes.

3. Northern has entered into a new five-year LNG Contract with Northeast Energy Center LLC ("NEC"). Under this LNG Contract, Northern delivers natural gas supply to NEC's LNG facility in Charlton, Massachusetts utilizing its Tennessee capacity during the summer periods to be liquefied and stored by NEC until such time as it can be called upon by Northern to be shipped to Northern's Lewiston LNG facility by truck. Under this LNG Contract, Northern can take up to 3,000 Dth per Day by truck and liquefy and store up to 75,000 Dth annually. Northern has entered into a corresponding five-year LNG trucking contract. This replaces the one-year LNG Contract and corresponding LNG trucking of similar volumes.

Peaking Contract 1, Peaking Contract 2, and the LNG Contract assure Northern of the availability of firm peaking supplies through the next five winter periods.

Q. Please provide an update on the Empress Capacity Agreements.

A. In August 2023, Northern entered into the following agreements with PNGTS and TransCanada:

1. Gas Transportation Contract for Firm Transportation Service between Portland Natural Gas Transmission System and Northern Utilities, Inc. dated August 22, 2023 (PNGTS Agreement);

2. 2024 Precedent Agreement between TransCanada Pipelines Limited and Northern Utilities, Inc. dated August 21, 2023 (2024 TCPL PA);

3. Firm Transportation Service Contract between TransCanada Pipelines Limited and Northern Utilities, Inc. dated August 21, 2023 (TCPL Agreement);

4. Precedent Agreement between Northern Utilities, Inc., and TransCanada Pipelines Limited dated August 21, 2023 (2027 TCPL PA).

Together these Agreements establish initial commitments between Northern and PNGTS and TCPL to provide a firm natural gas pipeline transportation capacity path from Empress, Alberta to Northern's interconnections with its affiliate, Granite State Gas Transmission; collectively, these Agreements comprise the Empress Capacity path. The Agreements provided Northern with the ability to add 12,500 Dth/day of incremental capacity to Northern's gas supply portfolio with service beginning April 1, 2024, for a thirty-year term. At the time that Northern entered into the Empress Capacity Agreements, TCPL expected to construct new facilities to support this capacity offering beginning November 1, 2027. As such, the 2024 TCPL PA and TCPL Agreement anticipate service from April 1, 2024 through October 31, 2027, and the 2027 TCPL PA anticipated service from November 2027 through March 2054. Notwithstanding these anticipated service dates, the Agreements collectively allow that service may commence under the 2027 TCPL PA on a date after November 1, 2027, and that service under the TCPL Agreement may therefore extend beyond October 31, 2027.

On June 10, 2024, TCPL advised Northern by letter that the project scope for the underlying expansion facilities required for service commencing on November 1, 2027 is being modified to reduce permitting risk and potentially reduce the overall cost of the project. TCPL also represented that it required additional time to refine the project scope and costs prior to seeking internal approvals, and that it had secured an extension of the operational agreement necessary to continue service under the TCPL Agreement for the additional period of time. TCPL and Northern agreed to amend the TCPL Agreement and the 2027 TCPL PA, allowing for a change in the expected in-service date of permanent facilities from November 1, 2027 to November 1, 2029 without any interruption of firm service due to the extension of the current operating agreement allowing TCPL to commence service under the TCPL Agreement. Critically, these amendments do not result in any disruption to the firm service obligations under the Empress Capacity Agreements; do not affect pricing under the Agreements; and do not extend the combined term of the Agreements beyond the 30-year period previously approved by the Commission. These amendments were filed with the Commission on July 1, 2024 under Docket No. DG 23-087.

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 2024-2025 Winter and 2025 Summer COG rates.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2024 through October 2025, 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 2024 through October 2025			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 22,563,500	Att NUI-FXW-5, Page 2 - Annual Pipeline Capacity Cost
2.	Storage Demand Costs	$ 37,587,294	Att NUI-FXW-5, Page 2 - Annual Storage Capacity Cost
3.	Peaking Allocated Pipeline Demand Costs	$ 1,295,100	Att NUI-FXW-5, Page 2 - Annual Peaking Capacity Cost
4.	Peaking Contract Costs	$ 13,016,750	Att NUI-FXW-5, Page 5 - Annual Fixed Charges
5.	Asset Management Revenue	$ (25,719,400)	Att NUI-FXW-5, Page 6 - Total Asset Management and Capacity Release Revenue
6.		$ 48,743,245	Sum Lines 1 through 5.

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. Page 2 of Attachment NUI-FXW-5 provides monthly and annual cost of Northern's pipeline and storage contracts. Page 3 and Page 4 of Attachment NUI-FXW-5 provide the corresponding demand billing determinant volume and demand billing rate for each pipeline and storage contract, respectively. Page 5 of Attachment NUI-FXW-5 provide peaking supply contracts costs, and page 6 provides the projected 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 2024-2025 Annual COG forecast annual demand cost compare with the 2023-2024 Annual COG forecast annual demand cost?

A. 2023-2024 Annual COG forecasted annual demand costs were equal to $37,271,543. 2024-2025 Annual COG forecasted annual demand costs are equal to $48,743,245, reflecting an increase in forecasted annual demand costs equal to $11,471,702 or 31%.

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

1. <u>Increase in projected Peaking Supply Demand Costs by $8,982,750.</u> A single-year peaking contract, which expired after last winter, was priced with no demand charges. The new five-year Peaking Contract 1 and Peaking Contract 2 include both demand and commodity components in the pricing, resulting in a significant increase in demand costs and a corresponding decrease in commodity costs.
2. <u>Increase in pipeline contract capacity costs in the amount of $2,234,152.</u> Pipeline capacity contract cost estimates increased $2,234,152 due mostly to a full year of Empress Capacity costs. PNGTS costs are anticipated to increase by $1,558,852, attributable to a full year of the 12,500 Dth of PNGTS capacity associated with the Empress capacity path. TCPL costs are anticipated to increase by $184,226, attributable to a full year of 12,890 Dth of TCPL capacity associated with the Empress capacity path, partially offset by lower anticipated TCPL tolls and more favorable foreign exchange rate against the Canadian dollar. Projected rate case increases on Algonquin are partially offset by rate decreases on Tennessee, Algonquin, and Texas Eastern.
3. <u>Lower projected Asset Management Agreement revenue in the amount of $254,800.</u> This reflects the results on Northern's annual RFP.

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-5, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Attachment NUI-FXW-6.

The 2024-2025 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $6,473,567.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2024 through April 2025?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 7 of Attachment NUI-FXW-6. The proposed Peaking Service Demand Charge is equal to $25.66 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, 2024.

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 0.958, 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 149,057 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, net of projected capacity assignment releases to both New Hampshire and Maine retail marketers. 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.[4]

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

Q. Please present the Company's commodity cost forecast for the 2024-2025 Annual Period.

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

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

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes November 2024 through April 2025			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Base Pipeline Resources	$ 17,914,508	5,807,033	$ 3.085
Storage Resources	$ 6,002,070	3,060,178	$ 1.961
Peaking Resources	$ 370,938	98,177	$ 3.778
Total Commodity Costs	$ 24,287,516	8,965,387	$ 2.709

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes May 2025 through October 2025			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Base Pipeline Resources	$ 5,261,526	2,652,070	$ 1.984
Storage Resources	$ -	-	
Peaking Resources	$ 83,522	11,040	$ 7.565
Total Commodity Costs	$ 5,345,048	2,663,110	$ 2.007

In summary, Winter Period net projected delivered commodity costs equal approximately $24.3 million at an average delivered rate of $2.709 per Dth, and Summer Period net projected delivered commodity costs equal approximately $5.3 million at an average delivered rate of $2.007 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 forecast commodity costs for the 2024-2025 Winter Period (November through April) compare with the forecast commodity costs presented for the 2023-2024 Winter Period COG?

A. As show in Table 5, above, the 2024-2025 Winter Period COG forecasted commodity costs are equal to $24,287,516 at an average delivered rate of $2.709 per Dth. The 2023-2024 Winter Period COG forecasted commodity costs were equal to $47,125,083 an average delivered rate of $5.159 per Dth. Overall, 2024-2025 forecasted Winter Period commodity costs are 48% lower than 2023-2024 forecasted Winter Period costs due primarily to a 47% decrease in projected average unit cost. The 2024-2025 projected delivered volume is 2% lower than was projected in 2023-2024. Projected NYMEX prices are 10% lower at the time of this 2024-2025 Annual Period COG filing (averaging $3.01 per Dth), compared to projected NYMEX prices at the time of last year's 2023-2024 Annual Period COG filing (averaging $3.36 per Dth). The Company's unit cost forecast reflects these lower NYMEX prices. The main factor contributing to lower overall projected delivered unit commodity cost is a reduction in peaking supply commodity costs due to lower volumes as the portfolio does not include any must-take peaking contracts. Other contributing factors include access to lower priced commodity due to the availability of the Empress capacity path for the full winter, as well as projected lower storage inventory costs.

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[5]. 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 requirement for November 2024 through March 2025, inclusive of both Maine and New Hampshire, is 8,021,318 Dth. Available supplies that will not be subject to NYMEX fluctuations during this period total 5,819,014 Dth, which is

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

73%, which is slightly below the Target Ratio of 75% under Northern's Price Risk Mitigation Plan. Fixed supplies are comprised of 4,913,301 Dth of available underground storage fixed price supplies, 380,000 Dth of NYMEX hedged baseload supplies and 550,000 Dth (Peaking Contracts 1 and 2) of fixed peaking supplies. Northern has currently locked the full volume of 380,000 Dth during the month of July 2024. Considering that Northern is already close to the Target Ratio, Northern does not intend to do additional hedging for the 2024-2025 Winter Period.

Q. Please summarize the NYMEX price lock executed under the Price Risk Mitigation Plan for the 2024-2025 Winter Period.

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 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-24	Dec-24	Jan-25	Feb-25	Mar-25
Block 1 Nov-Mar NYMEX Lock Volume	75,000	77,500	77,500	70,000	77,500
Block 1 Nov-Mar NYMEX Lock Price	$ 3.230	$ 3.230	$ 3.230	$ 3.230	$ 3.230
Block 1 Nov-Mar NYMEX Lock Cost	$ 242,250	$ 250,325	$ 250,325	$ 226,100	$ 250,325
Total NYMEX Lock Volume	75,000	77,500	77,500	70,000	77,500
Weighted Average NYMEX Lock Price	$ 3.230	$ 3.230	$ 3.230	$ 3.230	$ 3.230
Total NYMEX Lock Cost	$ 242,250	$ 250,325	$ 250,325	$ 226,100	$ 250,325
Current NYMEX	$ 2.579	$ 3.094	$ 3.377	$ 3.252	$ 2.936
Hedging Impact on Cost of Gas	$ 48,825	$ 10,540	$ (11,393)	$ (1,540)	$ 22,785

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 this allocation 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 2024 through October 2025.

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 forecast commodity costs for the 2025 Summer Period (May through October) compare with the forecast commodity costs presented for the 2024 Summer Period COG?

A. As show in Table 6, above, the 2024 Summer Period COG forecasted commodity costs are equal to $5,345,048 at an average delivered rate of $2.007 per Dth. The 2024 Summer Period COG forecasted commodity costs were equal to $6,088,689 at an average delivered rate of $2.490 per Dth. Overall, 2025 forecasted Summer Period commodity costs at the time of this 2024-2025 Annual Period COG Filing are 12% lower than 2024 forecasted Summer Period costs at the time of last year's 2023-2024 Annual Period COG Filing due to a 19% decrease in projected average unit cost and a 9% decrease in projected delivered volumes. Projected NYMEX prices are 5% lower for the 2025 Summer Period (averaging $3.10 per Dth), compared to projected NYMEX for the 2024 Summer Period (averaging $3.25 per Dth). The Company's unit cost forecast reflects these lower NYMEX prices. Lower delivered unit commodity cost projects for the 2025 Summer Period relative to the 2024 Summer Period also reflect lower projected adders to NYMEX for supply purchases.

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 upcoming Winter Period. Customers electing to migrate and purchase their supply from Northern shall be required to continue purchasing Northern's Sales Service until the following April 30. 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.

VI. Report on Available Hedging Strategies

Q. Please provide the report on available hedging strategies that was contemplated by the Settlement Agreement between Northern and the DOE in Docket No. DG 23-087, the approval of Northern's acquisition of Empress Capacity.

A. This report is provided as Attachment NUI-FXW-20.

Q. Does this conclude your testimony?

A. Yes, it does.