Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-2:

Reference: Northern's Sept. 17, 2024, filing

Please confirm that the Company is using the current EE charge (effective January 1, 2024) as a placeholder for the purposes of calculating the Company's LDAC to be effective November 1, 2024.

Response:

The EE charge is effective from January through December and is not changing on November 1. The EE charge shown on the LDAC rate summary is not a placeholder, it is the actual rate in effect. The Company will propose an EE charge effective January 1 on December 1, in accordance with HB 549 and will file an LDAC summary effective January 1, 2025 at that time.

Person Responsible: S Elena Demeris **Date:** 10/3/2024

Northern Utilities, Inc.
DG 24-102
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Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-3:

Reference: Northern's Sept. 17, 2024, filing and Kahl Testimony at Bates 000024; DOE Final Audit Report; DG 23-085, LDAC Reconciliation dated December 5, 2023

With regard to the COG season in Winter 2023-2024:

a. Please identify any issues the Audit Division has identified to date with regard to Northern's Winter 2023-2024 Reconciliation. Does Northern accept any recommendations DOE Audit has made?

Response:

The Audit Division identified two issues with Northern's Annual 2023-2024 Reconciliation. The first issue is that several rows in the total column of Form III, Schedule 2, Pages 1 & 2, were not filled in. However, this does not impact the total costs calculated nor the final reconciliation balance. Northern will submit to the Audit Division a revised Reconciliation with the missing totals filled in. In addition, the Local Production and Storage Allowance label and the Other A&G Allowance label were transposed. This has been also been corrected in the revised Reconciliation.

The second issue is a $4,000 discrepancy between the reconciliation and the general ledger. Northern agrees that the general ledger was not properly updated. The Company will update the general ledger for September 2024 to reflect the $4,000. This update will have no impact on the reconciliation.

Person Responsible: Chris Kahl **Date:** 10/3/2024

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-4:

Reference: Sept 17, 2024, filing

What NYMEX data was used to forecast the first of the month price for baseload quantities and the daily price (call option) for the Peak and Off-Peak Periods? Please provide documentation showing the NYMEX data and identify the date it describes, and the date it was obtained.

Response:

The NYMEX prices used for the commodity forecast for both Peak and Off-Peak Periods were the settlement prices as of September 5, 2024. (See Attachment NUI-FXW-10, Page 1, Bates Page 000211.)

DOE 1-4 Attachment 1 provides the requested documentation.

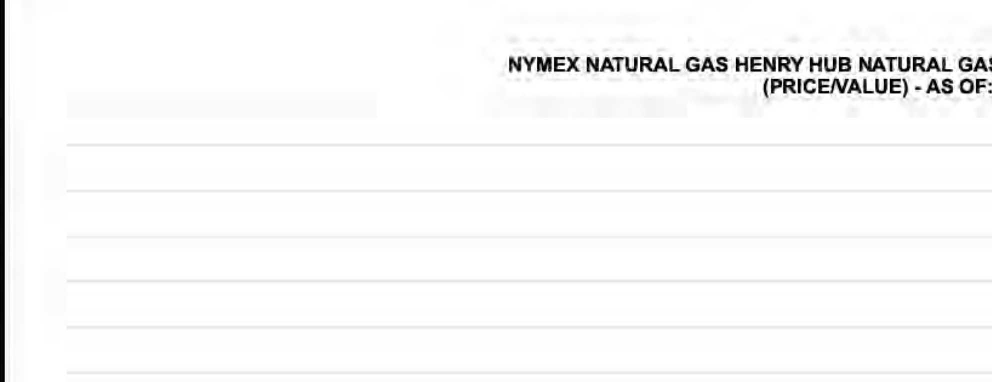
Person Responsible: Francis X. Wells **Date:** 10/3/2024

Commodity Charting

Series Type: Forward
Source: NYMEX
Location: Henry Hub
Instrument: Natural Gas Futures
Forward Term:
Forward Strip As Of: 09/05/2024
Measure: Price/Value
Add Series: NYMEX Natural Gas Henry Hub Natural Gas Futures (Price/Value) - As Of: 2024-09-05
Historical Period: 2 Years
Time Zone: Eastern Time (US & Canada)
C
F

[redacted]

[redacted] Natural Gas Henry Hub Natural Ga...



[redacted]

NYMEX NATURAL GAS HENRY HUB NATURAL GAS F[redacted]
(PRICE/VALUE) - AS OF: 2[redacted]

[redacted]

[redacted] ward natural gas curve models monthly forward values for regional gas hubs based on observed monthly q[redacted] d seasonal basis values, to facilitate monthly forward basis and full value review.

[redacted] ward power curve models monthly forward values for regional power hubs based on existing monthly forwa[redacted] d forward calendar year quotes.

N and CME Clearport market data provided by DTN.

REDACTED

ISO-sourced hourly and sub-hourly data is limited to one year of history for display. Additional history may be accessed by exporting selected data to Excel as SNL Formulas and adjusting the start/end history parameters.

ISO-sourced Alberta and Ontario Canadian power prices are reported in C$/MWh. U.S. power locations are reported in US$/MWh.

Only two different units of measure may be charted at the same time, i.e. energy prices with two different currencies or an energy price and an energy load.

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-5:

Reference: Sept 17, 2024, filing

a. Please provide summaries of the RFP responses to all of this year's RFPs (for Winter 2024-25 and Summer 2025) issued in the last 12 months, for all gas supplies. Please also provide a comparison of the RFP responses, focusing on the differences. Please include the date the RFP was issued and the date of the response. If no response to a particular RFP was received, please so indicate.

b. As compared to prior years, has the RFP process (for Winter 2024-25 and Summer 2024) been protracted or different in any way?

c. Please provide a table for last year's 2023-2024 Cost of Gas season Peak and Off-Peak seasons showing the different contracted for percentage quantities of natural gas, CNG, LNG, and propane.

d. Please provide a table for last year's 2024-2025 Cost of Gas season Peak and Off-Peak seasons showing the different contracted for percentage quantities of natural gas, CNG, LNG, and propane. Please explain the differences from the prior year as shown in question (c) above.

Response:

a. DOE 1-5 Attachment 1 CONFIDENTIAL provides copies of each RFP issued, as well as summaries of the responses received.
b. For the Winter 2023-2024 and Summer 2024 periods, the off-system peaking and LNG RFPs were for terms of one-year in duration. For the Winter 2024-2025 and Summer 2025, the off-system peaking and LNG RFPs requested terms longer than one-year in duration. Ultimately, Northern's off-system peaking contracts (Peaking Contract 1 and Peaking Contract 2), as well as Northern's LNG Contract were for five-year terms.
c. DOE 1-5 Attachment 2 provides the requested data.
d. DOE 1-5 Attachment 2 provides the requested data. With respect to the 2024-2025 Winter Period, significant percentage increases include the following.
    a. Empress increased from 3.1 percent of the 2023-2024 Winter Period to 19.1 percent of the 2024-2025 Winter Period due to the availability of the Empress Capacity Path for the entire Winter Period.
    b. Union Dawn Storage decreased from 46.8 percent of the 2023-2024 Winter Period to 35 percent of the 2024-2025 Winter Period due primarily

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to a reduction in estimated Dawn Hub supply purchases, due to the availability of lower cost Empress supplies and lower projected supply requirements.

c. Peaking Contract 1 estimated usage decreased from 6.4 percent in the 2023-2024 Winter Period to 0.7 percent in the 2024-2025 Winter Period because Northern is not required to purchase the entire contract quantity.

With respect to the Summer period, significant percentage changes to Empress, TGP Zone 4, and Atlantic Bridge are attributable to changes in relative prices and changes in total estimated volumes.

Person Responsible: Francis Wells **Date:** 10/3/2024

February 15, 2024

Northern Utilities, Inc. (NUI) seeks proposals from companies interested in managing transportation and storage assets within its portfolio for the upcoming term of April 1, 2024 – March 31, 2025. NUI also seeks proposals for firm supply for the term April 2024 - December 2024. NUI requests that responses be submitted via email using Attachment A to energy_contracts@unitil.com and please cc: hartigan@unitil.com. If you plan to submit a bid, and your company does not hold a credit rating of at least a BBB-/Baa3, please submit your company's latest financial statements. If there is not already a non-disclosure agreement ("NDA") in place between your company and NUI, please complete and include the attached NDA via email to energy_contracts@unitil.com by 5 PM Eastern Prevailing Time ("EPT") on February 19, 2024 so that it can be executed prior to the submission of bids. Please limit the editing of the NDA to only what is absolutely necessary as the Company's preference is a uniform NDA with counterparties. When responding to this request for proposal ("RFP"), please remember to use the attached bid sheet and to send it over in Excel format. Please do not embed bids within Word or PDF documents, and please refrain from sending marketing materials in an effort to expedite the contract awarding process. Term sheets with special conditions or contingencies will not be considered or accepted. Should there be any special terms or conditions regarding credit, operational issues, rate related issues, or other matters that a bidder wishes to address, these must be communicated prior to the submission of bids so that they can be discussed prior to the contract award process. **Bid submissions are due February 27, 2024 by 10:00 AM EPT.**

In order to address reliability concerns, NUI requires that the Asset Manager be the party that transports supply to the markets dispatched by NUI. Given this requirement, NUI will receive the upstream ID as it correlates to the capacity that is released to the Asset Manager as the upstream contract ID for nominated supply.

NUI encourages prospective bidders to have an executed NAESB in place prior to bidding. Please email energy_contracts@unitil.com if you do not currently have a NAESB in place with NUI, and would like to request one. The existence of an executed NAESB and the creditworthiness of the bidders, as determined by NUI, shall be factors in the award process. NUI reserves the right to select successful bidders according to criteria, which it establishes in its sole judgement, and also to reject any and all bids. NUI holds BBB+ S&P rating and Baa1 Moody's rating.

NUI requests that all bids and proposals for Asset Management Arrangements (AMAs) be compliant with FERC Order 712 as Asset Managers will be expected to conform to these regulations. The following language will be written into AMAs when capacity is released on pipeline Electronic Bulletin Boards:

> This release is made pursuant to an Asset Management Arrangement (AMA), as that term is used in FERC Order Nos. 712 and 712-A. Releasing shipper shall have the right on any day during the term of the release to call upon delivered gas supply service up to the MDQ of capacity of each asset released. Any such call on delivered gas supply service shall be subject to the terms and conditions negotiated in the Asset Management Arrangement.

The following language will be written into transaction confirmations for all AMAs:

> NUI shall have the right to terminate AMA transactions in the event that the Asset Manager fails to deliver for a period of three consecutive days, unless such failure is excused by Force Majeure or by pipeline restrictions that have resulted in curtailments to the priority level of service nominated by NUI. In either case, only the volume affected by the percentage curtailed will be excused. Such right is a Termination Option, pursuant to Sections 2.34 and 3.4 of the Base Contract. In the event that this Termination Option is exercised, damages for non-performance shall be calculated in the manner prescribed in Section 3.2 and Section 4.3 of the Base Contract and liquidation costs will be calculated in the manner prescribed in Section 10.3.1 of the Base Contract.
>
> For the purpose of AMA transactions, the term "Contract Value", as defined in Section 10.3.1 (Early Termination Damages Apply) of the NAESB, shall include any remaining AMA Fee to be paid by the Asset Manager as of the Early Termination Date, and the term "Market Value", as defined in Section 10.3.1 (Early Termination Damages Apply) of the NAESB, shall include the value of the asset management fee for any replacement asset management agreement

with respect to the capacity path that NUI enters into with replacement Asset Manager(s) in a commercially reasonable manner, pro-rated to the remaining term of the transaction.

In the event that NUI's capacity is curtailed due to a Force Majeure or pipeline restrictions, the Asset Manager must be willing to fill the curtailed capacity with an alternate supply source, if available, in order to bypass restrictions that affected the original nomination path. Any alternate supply will be at a mutually agreed upon price plus applicable variables to the requested delivery point(s).

Demand Credits: In the event that there is an outage that occurs on a capacity path and demand credits are potentially available, it is incumbent upon the Asset Manager to coordinate with Northern Utilities to nominate the supply in accordance with the pipeline tariff(s) which are affected in order to make Northern eligible for demand credits.

AMAs that allow for daily calls will have a 9:30 AM EPT nomination deadline in keeping with the ICE Day Ahead Trading Schedule. NUI will nominate the Monthly Baseload Gas volumes by 12:00 pm EPT at least five (5) Business Days prior to the first Day of each delivery Month during the Term and such volumes are not to exceed transportation contracts released as a part of this Transaction Confirmation (less any Retail Choice Capacity Assignments).

Certain capacity is recallable pursuant to the state mandated capacity release TCQ allocation change to retail marketers serving customers behind the utility. NUI reserves the right to adjust volume requirements to reflect fuel rate revisions or other mandatory capacity release changes. For each package that has assignable assets within it, actual February 2024 released volumes have been provided. Generally, Retail Choice Assignments are determined by migration to and from default service and retail suppliers so NUI is unable to provide precise volumes as that activity is unknown to the Company until monthly enrollments are finalized.

The effort required to respond to this request is greatly appreciated.

Sincerely,

Ann Hartigan
Manager, Gas Supply
T 603.773.6430
C 603.770.4630

Northern Utilities, Inc. (NUI)

Package 1– Iroquois Path AMA:

April 1, 2024 – March 31, 2025 - NUI will release the following capacity path to the successful bidder:

Pipeline	Rate Schedule	MDQ	Primary Receipt	Primary Delivery	Contract Number
Iroquois	RTS-1	6,569 Dth	Waddington	Wright	R181003
Tennessee	FT-A	4,267 Dth	Wright	Mendon	41099
Tennessee	FT-A	2,226 Dth	Wright	Agawam 1,382 Dth	95196
				Granite 844 Dth	
Algonquin	AFT-1	4,226 Dth	Mendon	Brockton	93002F

It is the Asset Manager's responsibility to make up any upstream volumes necessary to deliver the Tennessee and Algonquin citygate quantities should Tennessee, Algonquin, and/or Iroquois change the monthly fuel retention percentage(s).

NUI will baseload gas each month November through March as indicated below. Delivered supply of 2,226 Dth to Tennessee Zone 6 200 Leg and 4,226 Dth to Algonquin Brockton will be priced as follows.

The posted price as published by Platts' Monthly Bidweek Spot Gas Prices, under the heading "Northeast", "Iroquois, receipts" index plus variable transportation and fuel charges associated with deliveries shall apply to all Algonquin Brockton deliveries and all Tennessee Zone 6 200 Leg deliveries, based on the upstream MDQ and fuel retention factors for the capacity released.

Please note that the path with an MDQ of 844 Dth with primary delivery to Granite meter 420206 on Tennessee contract number 95196 and a corresponding portion 854 Dth of Iroquois contract number R181003 will be subject to the state mandated capacity assignment to retail marketers as part of the Maine and New Hampshire Retail Choice Programs. Releases from that path for the month of February 2024 are 233 Dth and 235 Dth, respectively. TGP baseload will be reduced by the actual volume released to retail marketers each month.

NUI Baseload (Dth/day)

Month	TGP	AGT
November	2,226	4,226
December	2,226	4,226
January	2,226	4,226
February	2,226	4,226
March	2,226	4,226

Operational Requirement: NUI requires that the Asset Manager for this capacity be the party that transports to the TGP markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's GID as the upstream ID. NUI requires that the Asset Manager for this capacity be the party that transports to the AGT markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's AGT contract number that corresponds with the AGT capacity assigned to them by NUI as the upstream ID. This will ensure that the Asset Manager manages confirmations rather than relying upon a third party to manage and communicate the status of confirmations.

Asset Optimization Value $______________________

Package 2 – Texas Eastern - Algonquin Path AMA:

April 1, 2024 – March 31, 2025 - NUI will release the following Texas Eastern and Algonquin capacity:

NUI will release to its Asset Manager 965 Dth of Texas Eastern (TETCO) capacity from FT-1 contract 800384 and 1,251 Dth of Algonquin (AGT) capacity from AFT-12 contract 93201A1C. The primary receipt on the Texas Eastern contract is the CNG Leidy Storage meter 75931 and the primary delivery meter is Algonquin, Lambertville, NJ meter 70087. The primary receipt on the Algonquin contract is 965 Dth at the Lambertville (Hunterdon, NJ) meter 210 and 286 Dth at Centerville – Transco (Morris, NJ) meter 220. The primary AGT delivery meter is Taunton (Bristol, MA) meter 11.

NUI will nominate 1,251 Dth as baseload for the term of November 2024 through and including March 2025 to AGT meter 11. Such deliveries will be priced at the posted price as published by Platts' Monthly Bidweek Spot Gas Prices as follows: 965 Dth will be priced at the 'Leidy Hub' index under the heading "Appalachia" plus variable transportation and fuel charges associated with deliveries on TETCO and AGT. In the event that there is no published price for a given month for 'Leidy Hub', NUI will pay 'Dominion, Appalachia'. 286 Dth will be priced at the 'Transco, zone 6 non-N.Y' index under the heading "Northeast" plus variable transportation and fuel charges on AGT associated with deliveries. Since there is not adequate TETCO capacity to deliver the full AGT MDQ, any volume necessary for fuel to facilitate maximum AGT deliveries from Lambertville, NJ will be priced at the 'Texas Eastern, M-3' index under the heading 'Northeast' plus variable transportation and fuel charges on AGT associated with deliveries.

This capacity is not released as part of the Maine and New Hampshire Retail Choice Programs.

Operational Requirement: NUI requires that the Asset Manager for this capacity be the party that transports to the AGT markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's AGT contract number that corresponds with the AGT capacity assigned to them by NUI as the upstream ID. This will ensure that the Asset Manager manages confirmations rather than relying upon a third party to manage and communicate the status of confirmations.

Asset Optimization Value: $________________

Package 3 – Tennessee Long Haul Capacity AMA:

April 1, 2024 – March 31, 2025 - NUI will release the following Tennessee long haul capacity from contract 5083:

Zone 0 North Pool	Zone 0 South Pool	Zone L, 500 Leg	Zone L, 800 Leg	Total
928	3,677	5,788	2,762	13,155

Primary receipts are at the relevant TGP Gulf pools. NUI reserves the right to release the Tennessee Zone 6 200 Leg primary delivery meters to the Asset Manager as follows: up to 4,349 Dth to Lawrence meter 420121, up to 1,539 Dth to Salem meter 420722 and/or up to 13,155 Dth to Granite Pleasant Street meter 420206. NUI will request from its Asset Manager city gate deliveries of 5,000 Dth as monthly baseload deliveries for the months of November and March. Additionally, during the months of November and March, NUI reserves the right to nominate the remaining portion as daily swing up to the full MDQ. For the months of December through and including February, NUI will request from its Asset Manager city gate deliveries totaling the full MDQ that remains after retail choice assignments as monthly baseload deliveries. For the months of April and October, NUI reserves the right to nominate up to the full MDQ as daily swing. NUI may request such deliveries at the primary delivery meters or at any other Tennessee Zone 6 200 Leg meter on a secondary basis.

Monthly baseload volumes will be priced at the monthly index as published by Platts' Monthly Bidweek Spot Gas Prices for the applicable supply zone plus variable commodity and fuel charges to Tennessee Zone 6 200 Leg. Daily swing nominations will be priced at the Tennessee midpoint daily price as reported by Platts' Gas Daily, under the heading "Daily price survey" for the applicable supply zone plus variable commodity and fuel charges to Tennessee Zone 6 200 Leg. This capacity is recallable pursuant to the state mandated retail marketer capacity assignment requirements in Maine and New Hampshire. The Asset Manager will be released 13,155 Dth less monthly retail choice assignments throughout the entire term. For February 2024 from contract 5083, 3,624Dth are released to marketers. Day ahead swing takes for this deal will be made ratably over weekends and holidays with notification by 9:30 AM EPT.

Operational Requirement: NUI requires that the Asset Manager for this capacity be the party that transports to the TGP markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's GID as the upstream ID. This will ensure that the Asset Manager manages confirmations rather than relying upon a third party to manage and communicate the status of confirmations.

Asset Optimization Value $_________________

<u>Package 4 – Tennessee Zone 5 200 Leg Niagara -> Tennessee Zone 6 200 Leg AMA:</u>

April 1, 2024 – March 31, 2025 - NUI will release the following Tennessee capacity:

NUI will release to its Asset Manager 2,335 Dth of TGP capacity (Contract 5292 - 1,406 Dth / Contract 39735 - 929 Dth), less monthly Retail Choice Assignments. Primary receipts are at the Niagara meter 410902. NUI reserves the right to release the Tennessee Zone 6 200 Leg primary delivery meters to the Asset Manager as follows: up to 24 Dth to Lawrence meter 420121 and/or up to 2,335 Dth to Granite Pleasant Street meter 420206.

NUI will baseload this supply for the twelve month term, April through and including March. For such deliveries, NUI will pay Platts' Monthly Bidweek Spot Gas Prices, under the heading "Northeast", "Niagara" index plus applicable variable commodity and fuel charges from Niagara to Tennessee Zone 6 200 Leg. In the event that there is no published price for Niagara for a given month, NUI will pay Platts' Monthly Bidweek Spot Gas Prices, under the heading "Upper Midwest", "Dawn, Ontario" index plus applicable variable commodity and fuel charges from Tennessee Zone 5 to Tennessee Zone 6.

NUI will request from its Asset Manager city gate deliveries of up to 2,335 Dth/day less retail choice assignments at the primary delivery meters or at any other Tennessee Zone 6 200 Leg meter on a secondary basis during the term.
The Asset Manager must be responsible for the administration and payment of all import/export filings, duties, GST tax, and any other miscellaneous charges.

This capacity is recallable pursuant to the state mandated retail marketer capacity assignment requirements in Maine and New Hampshire. The February 2024 release to marketers from contract 5292 is 387 Dth and from contract 39735 is 256 Dth.

Operational Requirement: NUI requires that the Asset Manager for this capacity be the party that transports to the TGP markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's GID as the upstream ID. This will ensure that the Asset Manager manages confirmations rather than relying upon a third party to manage and communicate the status of confirmations.

Asset Optimization Value $_________________

<u>Package 5 – Tennessee Sta. 313 Pool (meter 420891) Supply:</u>
a) April 2024 – October 2024 – 1,800 Dth NYMEX +/- basis: _________
b) November 2024 – 1,800 Dth NYMEX +/- basis: _________
c) December 2024 – 700 Dth NYMEX +/-basis: ________

<u>Package 6 – Tennessee Zone 4 300 Leg Delivered Supply to Northern Storage Injection Meter 460018:</u>
April 2024 - October 2024: 900 Dth NYMEX +/- basis: ____________

Package 7 – Canadian Storage and Pipeline AMA:

Delivery Period: April 1, 2024 – March 31, 2025

Capacity Release:

NUI will release the following transportation and storage capacity contracts less retail Capacity Assignment pursuant to NUI's Maine and New Hampshire Delivery Service Terms and Conditions. The portion of these contracts subject to Retail Choice Capacity Assignment may change on a monthly basis.

1.) Union Dawn Storage K# LST155 (Receipt and Delivery at Union Dawn)
    a. Maximum Storage Balance ("MSB") = 6,330,336 GJ (6,000,000 Dth)
    b. Maximum Daily Injection Demand (Firm December 1 through September 30)
        i. 0.75% of MSB (47,478 GJ / 45,000 Dth) provided current balance is less than 75% of MSB
        ii. 0.50% of MSB (31,652 GJ / 30,000 Dth) provided current balance is greater than or equal to 75% of MSB
        iii. October and November injections are on an interruptible basis
    c. Maximum Daily Withdrawal Demand
        i. June 1 through March 31 – Firm Withdrawal
            1. 1.05% of MSB (66,469 GJ / 63,000 Dth) provided that current balance is greater than or equal to 25% of MSB
            2. 0.8% of MSB (50,643 GJ / 48,000 Dth) provided that current balance is less than 25% of MSB
        ii. April and May withdrawals are on an interruptible basis
2.) Union Capacity K# M12256 (M12: Dawn to Parkway) – 42,962 GJ (40,720 Dth) (PNGTS C2C Path)
3.) Union Capacity K# M12296 (M12: Dawn to Parkway) – 10,814 GJ (10,250 Dth) (PNGTS PXP Path)
4.) Union Capacity K# M12279 (M12: Dawn to Parkway) – 10,875 GJ (10,307 Dth) (PNGTS WXP Path)
5.) TransCanada Capacity K# 57901 (FT: Parkway to E. Hereford) - 35,872 GJ (34,000 Dth) (PNGTS C2C Path)
6.) TransCanada Capacity K# 57055 (FT: Parkway to E. Hereford) - 6,333 GJ (6,003 Dth) (PNGTS C2C Path)
7.) TransCanada Capacity K# 63265 (FT: Parkway to E. Hereford) - 10,569 GJ (10,017 Dth) (PNGTS PXP Path)
8.) TransCanada Capacity K# 67167 (FT: Parkway to E. Hereford) – 10,660 GJ (10,104 Dth) (PNGTS WXP Path)
9.) TransCanada Capacity K# 71728 (FT: Empress to E. Hereford) – 13,600 GJ (12,890 Dth) – new capacity beginning April 1, 2024
10.) PNGTS C2C Capacity K# 208543 (Pittsburg to Newington Granite) – 40,003 Dth
11.) PNGTS PXP Capacity K# 233339 (Pittsburg to Newington Granite) – 10,000 Dth
12.) PNGTS WXP Capacity K# 240520 (Pittsburg to Dracut) – 10,000 Dth
13.) PNGTS Capacity K# 284292 (Pittsburg to Dracut) - 12,500 Dth – new capacity beginning April 1, 2024 / "2023 PNGTS Open Season Capacity"

These pipeline capacity contracts are subtotaled as follows:

Total Union Capacity from Dawn to Parkway – 64,651 GJ (61,277 Dth)

Total TCPL Capacity from Parkway to E. Hereford – 63,434 GJ (60,124 Dth)
Total TCPL Capacity from Empress to E. Hereford – 13,600 GJ (12,890 Dth)
Total TCPL Capacity to E. Hereford – 77,034 GJ (73,014 Dth)

Total PNGTS Capacity – 72,503 Dth

Please note new capacity for Northern beginning effective April 1, 2024. Additional volume for the new TCPL capacity may at certain times be in excess of the volume needed to fill the new PNGTS capacity, depending on the fuel and measurement variance rates in effect on PNGTS. In these circumstances, as discussed more fully below, any such additional TCPL capacity shall be used to fill Northern's other PNGTS contracts.

Beginning Storage Balance: As of February 13, 2024, NUI's current inventory balance in Union Dawn Storage K# LST155 is approximately 1.6 million GJ at an average inventory rate equal to approximately $2.596 USD per GJ. On April 1, 2024, the Asset Manager will purchase any remaining inventory from NUI at the average inventory rate.

Monthly Changes in Capacity Assignment: The volume of capacity release out of the transportation and storage contracts listed above may change on a monthly basis, pursuant to the respective Delivery Service Terms and Conditions for NUI's Maine and New Hampshire Divisions.

Monthly changes to storage inventory to or from the Asset Manager will be made as needed during the Delivery Period to fulfill NUI's capacity assignment obligations to retail marketers. Such monthly inventory transfers will occur at the weighted average cost of gas as of the end of the month prior to the inventory transfer. The Asset Manager agrees to sell these inventory transfer volumes to NUI when the net assigned Maximum Storage Balance to Maine and New Hampshire retail marketers' increases and to purchase these inventory transfer volumes from NUI when the net assigned Maximum Storage Balance to Maine and New Hampshire retail marketers decreases. The weighted average cost of gas as of the end of the month prior to the inventory transfer shall be the price for these purchases and sales under the AMA. As discussed in section B., below, any such purchases of inventory transfer volumes by the Asset Manager will be repurchased by NUI as of April 1, 2025.

Injection Portion of the Delivery Period:

As of February 13, 2024, there are roughly 1.6 million GJ remaining in storage. The difference between the volume of MSB released to the Asset Manager under this AMA (MSB less ME and NH retail capacity assignment, referred to as the "Released MSB") and the Beginning Storage Balance (such difference shall be referred to as the "Injection Volume") will be presumed to be injected on the following monthly schedule. The Injection Volume can change throughout the injection period below on a monthly basis, due to changes in ME/NH Capacity Assignment.

Monthly Volume Injected

Month	Monthly Injection Volume
April	(75% times Released MSB minus Beginning Storage Balance) divided by 4
May	(75% times Released MSB minus Beginning Storage Balance) divided by 4
June	(75% times Released MSB minus Beginning Storage Balance) divided by 4
July	(75% times Released MSB minus Beginning Storage Balance) divided by 4
August	12.50% times Released MSB
September	12.50% times Released MSB

The Asset Manager agrees that the target end of month inventory for July 2024 is 75% and for September 2024 is 100% of the Released MSB. September 2024 Percentage Injection Volume will be adjusted to achieve this target, so long as such adjustment would not require injections in excess of the applicable Maximum Daily Injection Demand. In such a case, the volume injected would reflect the Maximum Daily Injection Demand for each day of the month.

Each month's Injection Volume will be priced as described below:

Platts' Monthly Bidweek Spot Gas Prices, under the heading "Upper Midwest", "Dawn, Ontario" Index plus variable injection and fuel charges prescribed in Union K#LST155. Seller agrees that injections under this AMA do not encumber any of the Union Capacity from K# M12256, K# M12296, or K# M12279 released to Seller under this agreement.

Following each month of the injection portion of the Delivery Period, the Asset Manager shall send a statement to NUI, detailing the injection costs incurred by NUI during the month and updating the weighted average cost of the Injection Volume and the Beginning Storage Balance. However, payment for storage refill shall be made in accordance with section B, below. NUI will not request injections into Union K# LST155 storage during the months October 2024 – March 2025.

A. NUI will nominate daily storage withdrawals for deliveries to primary or secondary delivery points anywhere on PNGTS. Nominations in keeping with the ICE Day Ahead trading schedule may be **non-ratable** over weekends and holidays with requests made by 9:30 AM EPT. Incremental intraday storage withdrawals will be scheduled on a best efforts basis based on restrictions within the path. Intraday reductions to storage withdrawals are made frequently for balancing and these reductions frequently occur in the late day cycle up to 9:00 AM EPT for the outgoing gas day but may be nominated at any nomination cycle during the gas day. Reductions to storage withdrawals may be limited by the Asset Manager to applicable EPSQ on the TransCanada Mainline (East Hereford) but the Asset Manager may allow NUI to reduce withdrawals in excess of EPSQ if they have a market for the supply. In addition to reductions to storage withdrawals, NUI reserves the right to make nomination changes redirecting supply on PNGTS throughout the intraday cycles as well as for the 9 AM EPT morning cycle for the outgoing gas day. Such nominations redirecting supply on PNGTS will not be limited to EPSQ unless PNGTS has EPSQ in enforcement at the meters NUI is attempting to reduce. All of the nomination activity described herein requires that the Asset Manager be available to facilitate those nominations.

B. The storage volumes withdrawn during November 2024 – March 2025 will be priced at the final weighted average cost of the September 2024 inventory plus applicable monthly variable commodity and fuel costs to deliver to PNGTS city gates. **NUI will pay for storage withdrawn on a monthly basis during the winter months, and will repurchase any remaining inventory as of April 1, 2025 at the final weighted average cost.**

C. The monthly MDQs released to the Asset Manager will be equal to the capacity that is remaining after Retail Choice Assignments have been made. Current releases from this path for February 2024 are: from Union Dawn storage MSB 1,329,192 GJs, MDWD 13,957 GJs and MDID 9,969 GJs, Union transportation capacity 13,574 GJs, TCPL (Parkway to E. Hereford) transportation 13,319 GJs, PNGTS K# 208543 (PNGTS C2C) is 8,399 Dth, PNGTS K# 233339 (PNGTS PXP) is 2,100 Dth, and PNGTS K# 240520 (PNGTS WXP) is 2,100 Dth. Estimated capacity assignment for TCPL (Empress to E. Hereford) transportation is 2,425 GJ. Estimated capacity assignment for new PNGTS K# 284292 is 2,229 Dth.

D. NUI reserves the right to call on the MDQ of the remaining transportation capacity after Retail Choice Assignments for delivery on PNGTS up to the following volumes by month. Please note that the months that list the full MDQ will be adjusted down after Retail Choice Assignments:

Month	Up to Dth/day
Apr-24	72,503
May-24	72,503
Jun-24	25,000
Jul-24	20,000
Aug-24	20,000
Sep-24	25,000
Oct-24	72,503
Nov-24	72,503
Dec-24	72,503

Jan-25	72,503
Feb-25	72,503
Mar-25	72,503

E. On PNGTS, the order of dispatch for NUI's nominated daily supply will always exhaust the PNGTS C2C Capacity K# 208543 before the PNGTS PXP Capacity K# 233339, and the last PNGTS contracts to be dispatched will be PNGTS WXP Capacity K# 240520 and the 2023 PNGTS Open Season Capacity K# 284292 (new capacity as of April 1, 2024), which both have the same rates.

F. Supply nominated during the months of April through October will utilize the Empress capacity path first and then the Dawn capacity path. The first dispatch will be priced at the posted price as published by Platts' Canadian Gas Price Reporter ICE NGX AB-NIT Same Day Index (5A) US/MMBtu, plus ICE NGX AB-NIT/TCPL-Empress Transport Day Ahead Index US/MMBtu, plus variable costs and fuel to transport the requested delivery quantity from Empress to PNGTS until the portion of TransCanada Capacity K# 71728 (FT: Empress to E. Hereford) – 13,600 GJ (12,890 Dth) released to the Asset Manager remaining after fulfilling baseload volumes set forth in Section G below is fully utilized. Volumes nominated above this level up to the applicable monthly MDQ in Section D will be priced at Platts' Gas Daily Final Daily Price Survey 'Upper Midwest', 'Dawn, Ontario' Index plus variable costs and fuel to transport the requested delivery quantity to PNGTS.

G. During the months of April and October, NUI will baseload 4,000 Dth/day. During the months of December through February, NUI will baseload 7,500 Dth/day. Such baseload volumes will utilize the portion of TransCanada Capacity K# 71728 (FT: Empress to E. Hereford) – 13,600 GJ (12,890 Dth) released to the Asset Manager and will be priced at the posted price as published by Platts' Canadian Gas Price Reporter ICE NGX AB-NIT Month Ahead Index (7A) US/MMBtu plus ICE NGX AB-NIT TCPL-Empress Month Ahead Spread (7AA) US/MMBtu plus variable costs and fuel to transport the requested delivery quantity from Empress to PNGTS. Daily supply nominated during the months of November through March will dispatch storage withdrawals, then any remaining Empress-based supply after fulfilling baseload volumes set forth in this Section, before Dawn based non-storage supply. The pricing for storage withdrawals is outlined in Section B. The price for Empress-based daily supply nominations is based on Platts' Canadian Gas Price Reporter Platts' Canadian Gas Price Reporter ICE NGX AB-NIT Same Day Index (5A) US/MMBtu, plus ICE NGX AB-NIT/TCPL-Empress Transport Day Ahead Index US/MMBtu, plus variable costs and fuel to transport the requested delivery quantity from Empress to PNGTS. The price for Dawn-based daily supply nominations is Platts' Gas Daily Final Daily Price Survey 'Upper Midwest', 'Dawn, Ontario' Index plus variable costs and fuel to transport the requested delivery quantity to PNGTS.

H. On a daily basis, when NUI has maxed out its available storage withdrawal, as well as seasonally, when NUI hits storage withdrawal ratchets, for any takes that are non-storage based, NUI's daily calls will be priced as outlined in Section G above. NUI reserves the right to call on supply at this pricing structure in order to make up the difference between the storage volume and the MDQ. As discussed in Section G, daily calls of Dawn-based supplies will be dispatched after storage- and Empress-based volumes.

I. On a monthly basis, after fuel rates have been calculated, NUI reserves the right to buy supply at East Hereford US from the Asset Manager at a mutually agreeable price in order to fill to the MDQ of the downstream PNGTS capacity if the total MDQ of TCPL contracts released to the Asset Manager is insufficient to cover fuel and measurement variance on PNGTS needed to deliver the full MDQ of the PNGTS capacity released to the Asset Manager. If a mutually agreeable price cannot be struck for this supply between NUI and the Asset Manager, NUI may elect to buy that supply from another party to fill the PNGTS capacity which will be transported by the Asset Manager. The February 2024 volume needed at East Hereford US to fill PNGTS capacity is 0 Dth.

J. NUI reserves the right to sell supply purchased under this transaction confirmation to parties on PNGTS. When valuing this deal, it is imperative that the bidder take this into consideration and not submit responses that presume that NUI gives up this contractual right.

K. The PNGTS capacity within this AMA path is derived from four different PNGTS Open Seasons that have different rates and terms, C2C K# 208543, PXP K# 233339, WXP K# 240520, and PNGTS K# 284292 (new capacity as of April 1, 2024), resulting from PNGTS Open Season issued on June 6, 2023 (the "2023 PNGTS Open Season Capacity"). NUI will release this capacity at a $0.00 demand cost to the Asset Manager. Canadian transportation and storage releases will be made to the Asset Manager at max rate for which NUI will reimburse the Asset Manager. Deliveries on PNGTS using the C2C capacity to any of the following points along the Joint Facilities will not incur incremental commodity charges:

Meter#	Name	Operator
50525	Westbrook	M&NE
50600	Westbrook	Granite State
20650	Gorham	Maine Natural Gas
51241	South Berwick	Granite State
50725	Eliot	Granite State
50750	Eliot CNG	XPress Natural Gas
20775	Newington	Essential Power
20900	Newington	Eversource
50850	Newington	Granite State
51000	Haverhill	Tennessee Gas Pipeline
51025	Haverhill	National Grid
51050	Methuen	M&NE
51150	Dracut	Tennessee Gas Pipeline

L. Deliveries using NUI's PNGTS C2C capacity to any PNGTS point that is not included on the list above will incur an incremental commodity charge of $0.2543/Dth. This incremental commodity charge could be incurred by NUI as a result of requests for delivery to points that are not listed or could be incurred by the Asset Manager as a result of their own optimization activity. NUI will pay the Asset Manager for any incremental charges that result from NUI's requests for deliveries to points not listed above.

M. Deliveries on PNGTS using the PXP capacity to any of the following points along the Joint Facilities will not incur incremental commodity charges:

Meter#	Name	Operator
50525	Westbrook	M&NE
50600	Westbrook	Granite State
51241	South Berwick	Granite State
50725	Eliot	Granite State
50850	Newington	Granite State
51000	Haverhill	Tennessee Gas Pipeline
51150	Dracut	Tennessee Gas Pipeline

N. Deliveries using the PNGTS PXP capacity to any PNGTS point that is not included on the list above and/or receipts from any point other than the primary receipt at Pittsburg, NH will incur an incremental commodity charge equal to the PNGTS system daily recourse rate, $0.8543 per Dth minus the PXP Negotiated Daily Demand Rate, which is $0.7448 per Dth. This commodity charge could be incurred by Northern as a result of requests for delivery to points that are not located on that list or it could be incurred by the Asset Manager as a result of their own optimization activity. For any incremental commodity charges that are the result of Northern's requests for deliveries to said points, Northern will pay the Asset Manager. PXP capacity also has a $0.0091 per Dth usage (commodity) charge regardless of delivery point.

O. Deliveries using PXP capacity on PNGTS are subject to both Measurement Variance on PNGTS and the Fuel Rate that is applicable to PXP Phase III.

P. Deliveries on PNGTS using either the WXP or the 2023 PNGTS Open Season Capacity to any primary or secondary points on PNGTS will not incur incremental commodity charges. Deliveries using either WXP capacity or 2023 PNGTS Open Season Capacity on PNGTS are subject to both Measurement Variance on PNGTS and the Fuel Rate that is applicable to WXP.

Q. As previously mentioned, the Asset Manager will be paid for the inventory as NUI withdraws the supply during the winter months. The financing requirements that are inherent to this deal should be contemplated and carefully reviewed when evaluating whether or not this particular AMA is a good fit for your company. Similarly, NUI will perform its due diligence in reviewing the latest financial statements of any bidder that is interested in this deal. If there are credit constraints or additional requirements requested of NUI that are or could be the result of this contractual obligation, it is imperative that these be made clear and discussed prior to the bid submission so that they can be part of the contract negotiation prior to awarding the deal. If such financial responsibilities are not feasible for your organization, please do not bid on this deal.

R. As a precautionary measure that is intended to ensure reliability for NUI's customers, NUI requires that the Asset Manager have an **actual** physical balance in NUI's storage at Dawn of 95% inventory by November 1, 2024. The Asset Manager will send verification that NUI's storage inventory is at least 95% full once inventory transfers have been completed for November business.

S. The Asset Manager will be responsible for the administration and payment of all import/export filings, duties, taxes, and any other miscellaneous charges associated with transporting the volumes above from the applicable receipt point to NUI on PNGTS. NUI will be responsible for applicable taxes that may be assessed in connection with the Union storage contract. In the case of inventory transfers that may occur due to changes in Retail Choice Assignments, the buyer of the inventory transfer volume shall be responsible for applicable taxes. Retail marketers taking transportation and storage capacity assignment from this path will be responsible for their own administration and payment of all import/export filings, duties, taxes, and any other miscellaneous charges associated with their share of these assets.

T. **Operational Requirement:** NUI requires that the Asset Manager for this capacity be the party that transports on all of the capacity along the path to the markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's upstream contract number that corresponds with the PNGTS capacity released to them by NUI as the upstream ID. This will ensure that the Asset Manager manages confirmations along the path rather than relying upon a third party to manage and communicate the status of confirmations.

Asset Optimization Value: _______________

Package 8: AGT->MNUS Atlantic Bridge AMA:

April 1, 2024 – March 31, 2025: NUI will release the following path to the successful bidder:

Pipeline	Rate Schedule	MDQ	Primary Receipt	Primary Delivery	Contract Number
Algonquin (AGT)	AFT-1AB	7,599 Dth Less ME/NH Capacity Assignment	00201 - MAHWAH (BERGEN,NJ) 00214 - RAMAPO - MILLENNIUM (ROCKLAND,NY)	01215 - SALEM ESSEX CO., MA NORTH (ESSEX,MA)	510939
Maritimes US (MNUS)	MN365AB	7,500 Dth Less ME/NH Capacity Assignment	30035 - BEVERLY-ESSEX CO., MA (BI-DIR 30025) FLOW NORTH	30028 - NORTHERN UTILITIES-COTTON RD DELIVERY - ANDEROSCOGGIN CO, ME	210363

Please note that this capacity path will be subject to the state mandated capacity assignment to retail marketers as part of the Maine and New Hampshire Retail Choice Programs. The monthly MDQs released to the Asset Manager will be the remaining capacity after Retail Choice Assignments have been made. For the month of February 2024, the projected releases from this path total: 2,094 Dth on AGT and 2,066 Dth on MNUS.

In order to be eligible for demand credits on this capacity path, NUI shall release this capacity at max tariff rates to the Asset Manager as $0.00 rate releases are not eligible for demand credits on AGT and MNUS. Demand charges will be reimbursed in the monthly invoicing process.

NUI will have the option to call on delivered Maritimes US (MNUS) supply up to the maximum daily quantity on a daily or monthly basis from April 1, 2024 – March 31, 2025.

In the event of an AGT outage that interrupts receipts from AGT, NUI reserves the right on a daily basis to utilize up to the full MDQ of the MNUS capacity that remains after Retail Choice Assignments to receive supply sourced from PNGTS at the Westbrook interconnection between MNUS and PNGTS. NUI will request deliveries from its Atlantic Bridge Asset Manager on MNUS utilizing Westbrook PNGTS receipts. NUI will sell the PNGTS supply to the Atlantic Bridge Asset Manager for $0.00/dth. NUI will purchase the MNUS delivered supply from its Asset Manager for $0.00/dth and will reimburse the Asset Manager for any applicable commodity charges.

Outside of an outage situation, the election to request this supply as a daily call or as a monthly baseload quantity less than the full MDQ can be made up to five business days prior to the new month. If no election to make a given month a daily call option is made, that month will be priced as a monthly baseload call at the full MDQ. Daily swing elections will be made in keeping with the ICE Day Ahead trading schedule by 9:30 AM Eastern Prevailing Time (EPT) and will be ratable over weekends and holidays. For the months of July 2024 and August 2024, NUI will cap its election for daily or monthly quantities at the lower of 3,000 Dth or the monthly MDQ released to the Atlantic Bridge Asset Manager. Monthly and daily requests will be priced as follows:

Daily swing elections will be priced at the index price ($/MMBtu) as published by Platts' Gas Daily*,* under the heading "Northeast", "Tx. Eastern, M-3" index plus applicable variable transportation and fuel charges associated with deliveries to MNUS delivery points. Please indicate any adders or discounts to the M3 index as part of your bid submission.

Monthly baseload elections will be priced at the index price ($/MMBtu) as published by Platts' in Inside FERC as the Monthly Bidweek Spot Gas Prices under the heading 'Northeast', 'Texas Eastern, M-3' index plus applicable variable transportation and fuel charges associated with deliveries to MNUS delivery points. Please indicate any adders or discounts to the M3 index as part of your bid submission.

During the months of April through and including June as well as October through and including March, requests of delivered MNUS supply can be made to any MNUS meter (primary and/or secondary). During the months of July through and including September, requests of MNUS delivered supply can be made to any MNUS meter on the Joint Facilities – i.e. south of Westbrook MN/PNGTS interconnect meter 35006.

Operational Requirement: During the months of November through and including April, NUI requires that the Asset Manager for this capacity be the party that transports on the AGT and MNUS capacity released as part of this AMA to the MNUS markets dispatched by NUI rather than passing NUI's points to a third party. During the months of May through and including October, NUI requires that the Asset Manager for this capacity be the party that transports on the MNUS capacity released as part of this AMA to the MNUS markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive the Asset Manager's MNUS contract number that corresponds with the MNUS capacity assigned to them by NUI as the upstream ID. This will ensure that the Asset Manager manages confirmations rather than relying upon a third party to manage and communicate the status of confirmations.

NUI reserves the right to make nomination changes redirecting supply on MNUS throughout the intraday cycles as well as for the 9 AM EPT morning cycle for the outgoing gas day. Such nominations redirecting supply on MNUS will not be limited to EPSQ unless MNUS has EPSQ in enforcement at the meters NUI is attempting to reduce. During the months of July through and including September, such redirections of supply will only be made to meters south of meter 35006. All of the nomination activity described herein requires that the Asset Manager be available to facilitate those nominations and are subject to approval from MNUS.

Please submit the Asset Optimization Value and any adders or discounts to the index in the attached Bid Form.

Asset Optimization Value: _______________

RFP Recipients - AMA and Pipeline Gas Supply / Long Term Peaking Supply

BP
Calpine
Castleton
Citadel
ConEd
Conoco Phillips
Constellation
Direct Energy
DTE Energy
Emera Energy
Energy Atlantica
Excelerate Energy
Freepoint
Goldman Sachs
Irving
Mercuria
Morgan Stanley
NextEra
NJR
Range Resources
Repsol
Sequent
Shell
SWN
Tenaska
Twin Eagle
Vitol

REDACTED
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	Iroquois AMA	TE > AGT AMA	TGP Long Haul AMA	TGP Niagara AMA	TGP 313 Pool Supply			TGP N. Storage	Union AMA	AGT > MN AB AMA		
	APR24-MAR25	APR24-MAR25	APR24-MAR25	APR24-MAR25	APR24-OCT24	NOV24	DEC24	APR24-OCT24	APR24-MAR25	APR24-MAR25		
	Asset Optimization	Asset Optimization	Asset Optimization	Asset Optimization	1800/day	1800/day	700/day	900/day	Asset Optimization	Asset Optimization	TE, M-3 Daily +/-	TE, M-3 Monthly +/-

[redacted]

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October 31, 2023

Northern Utilities, Inc. ("NUI") announces a Request for Proposals ("RFP") for firm natural gas peaking supply services for the winter seasons November through and including March for either a three year or a five year term commencing November 1, 2024. The peaking supply service secured through this RFP will be used to meet NUI's demand for swings and peak winter days. Northern seeks bids that allow both ratable and non-ratable weekend and holiday supply preferably with intraday call rights that allow for increases and/or decreases. In order to ensure reliability of this peaking service, NUI requests proposals from service providers that hold Firm assets to back their bids. The delivery point(s) within those Firm assets must be at or deliverable to certain delivery points that are NUI or Granite State Gas Transmission interconnects with the Portland Natural Gas Transmission System or Maritimes & Northeast U.S. Pipeline.

If you plan to submit a bid and there is not already a non-disclosure agreement in place between your company and NUI, please partially execute and send the attached N.D.A. by 5 PM EPT on November 6, 2023. Please limit the editing of the N.D.A. to only what is necessary as the Company's preference is a uniform N.D.A. with counterparties. If your company does not hold a credit rating of at least a BBB-/Baa3, please submit your company's latest financials by November 9, 2023. When responding to the RFP, please use the attached bid sheet and to send it over in Excel format. Please do not embed bids within Word or PDF documents, and please refrain from sending marketing materials in an effort to expedite the awarding process. Term sheets with special conditions or contingencies will not be considered or accepted. Should there be any special terms or conditions regarding credit, operational issues, rate related issues, etc. that a bidder wishes to address, these must be communicated prior to the submission of bids so that they can be discussed prior to the award process. Bid submissions, N.D.A.'s, and financials must be submitted via email to energy_contracts@unitil.com and please cc: hartigan@unitil.com. **Bid submissions are due November 15, 2023 by 10:00 AM EPT.**

NUI encourages prospective bidders to have an executed NAESB in place prior to bidding. Please email energy_contracts@unitil.com if you do not currently have a NAESB in place with NUI. The existence of an executed NAESB and the creditworthiness of the bidders, as determined by NUI, shall be factors in the award process. NUI reserves the right to select successful bidders according to criteria, which it establishes in its sole judgement, and also to reject any and all bids. NUI holds BBB+ S&P and Moody's Baa1 ratings.

The effort required to respond to this request is greatly appreciated. If you have any questions or concerns, please feel free to contact me. Thank you for your responses in advance.

Sincerely,

Ann

Ann Hartigan
Manager, Gas Supply

T 603.770.4630

Northern Utilities, Inc. ("NUI")
Winter Peaking RFP:

Term: Winters November 1 – March 31 for either a three or five year term starting November 1, 2024

Quantity: NUI seeks a peaking service with a maximum daily quantity (MDQ) **up to** 25,000 Dth and a maximum annual contract quantity (ACQ) **up to** 500,000 Dth, providing a 20 day peaking service. NUI may nominate between 0 Dth and 25,000 Dth/day of supply for each day during the term. Total supply nominations shall be limited to 500,000 Dth each year over the term. NUI will consider bids for the entire volume sought through this RFP or portions of the requested volumes.

Delivery Points: The bidder should indicate (in the attached Bid Form) the maximum daily quantity and annual contract quantity available to NUI through this RFP at each of the Delivery Points which NUI is seeking through this RFP. If you are able to offer peaking on both pipelines, please show offers for both **separately** on the attached bid form.

Westbrook Granite State Interconnect - accessible via Maritimes meter 30005 and/or PNGTS meter 05-0600.

Cotton Road – Maritimes meter 30028. Not accessible via PNGTS.

Newington Granite State Interconnect **-** accessible via PNGTS meter 05-0850. Not accessible via Maritimes.

South Berwick Granite State Interconnect - accessible via Maritimes meter 30056 and/or PNGTS meter 05-1241. (Maritimes' maximum meter capacity is 10,000 dth/day)

Pricing: If the price of your peaking bid includes a demand charge, the demand charge within your bid should include the total dollar amount (monthly and annual) so that demand calculations do not need to be clarified. Northern will consider 'must take' pricing with a fixed commodity price or index based commodity pricing without 'must take' requirements.

Nominations: NUI will have the right to a day-ahead call upon any quantity of peaking service up to the maximum daily quantity (MDQ) on any day during the term of service. NUI prefers peaking supply arrangements that allow non-ratable takes over weekends and holidays. NUI also prefers peaking supply arrangements that allow intraday increases and/or decreases. Bidders should provide specific details of its proposed nomination provisions in the attached Bid Form.

Term: Please note that the Bid Form has a tab for a three year term and a tab for a five year term commencing November 1, 2024.

Submission Instructions:
Proposals must be received no later than 10:00 AM EPT on November 15, 2023. Proposals must be submitted via e-mail with bids included in the Bid Form in Excel format to energy_contracts@unitil.com and please cc: hartigan@unitil.com. You will receive an email confirming receipt of your bid proposal. All inquiries regarding this RFP should be directed to:

Ann Hartigan
Manager, Gas Supply
Ph: (603) 770-4630 / E-mail: hartigan@unitil.com

REDACTED
Redacted

	Bidder	Term	MDQ	ACQ	Annual Demand	Monthly Demand	Demand / ACQ	Commodity	Non-Ratable	Nomination Details	Delivery Points	Other
[redacted]												

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Northern Utilities, Inc. ("NUI") Long Term LNG Supply RFP

- Maximum Term: NUI will consider bids for any term up to a maximum of ten years starting 11/1/2024
- Minimum Term NUI seeks terms no less than one year starting 11/1/2024
- Volume: Up to 75,000 Dth of LNG at max of 3 trucks
- Delivery: NUI requests interested suppliers to send offers for LNG supply with and without trucking to its Lewiston, ME LNG facility

Proposal Requirements

The attached Proposal Information Form must be completed and submitted with each proposal. In addition to the Proposal Information Form, each respondent must also provide the following information:

- A detailed description of the proposed supply arrangement including the supply and transportation resources available to the proposal sponsor to fulfill its supply obligation.
- Pricing and specific terms and conditions of the proposed supply.
- Nomination procedures and deadlines
- Background information on the proposal sponsor, including company history and its performance record delivering similar gas supply arrangements.
- A link to the most recent Annual Report to Stockholders or other documents that characterize the proposal sponsor's financial condition.
- Any additional information that the proposing entity believes is pertinent to the proposal(s) being submitted.
- The proposed base contract (including the proposed credit terms), if one does not already exist between NUI and the supplier

Submission Instructions

Bid Proposals must be received no later than **10:00 AM EPT on Tuesday March 5, 2024.**

Evaluation

- Lowest evaluated bid price over the supply obligation period
- Proximity of LNG supply source to Lewiston, ME
- Availability of trucking from proposed LNG supply source to Lewiston, ME
- Gas quality specifications of proposed LNG supply
- Financial and operational viability of the gas supplier, including the provision of adequate financial security, the length of trucking haul required to deliver supply to Company's LNG facility and the adequacy of the local LNG facilities.
- Responsiveness to non-price requirements including but not limited to the reasonable extension of financial credit to NUI

Conditions

This is not an offer to contract but a request for proposals. NUI retains the right to suspend or cancel this RFP and to revise or amend its terms. NUI reserves the right to reject any or all proposals received or to accept any proposal received in its entirety or any part thereof. NUI is under no obligation to accept the lowest cost proposal or to return any proposals or materials submitted in response to this RFP.

NUI, at its sole discretion, reserves the right to issue additional instructions or requests for additional information, to extend the due date, to modify any provision in the RFP or any appendix hereto or to withdraw the RFP.

Address of Lewiston LNG Plant
95 River Road
Lewiston, ME 04240

RFP Recipients – LNG Supply

UGI
Energir
Constellation
Liberty Energy Trust (Northeast Energy Center)
Preload International
NextEra
Dominion
Niche
Clear Energy

A. Qualitative Assessment of LNG Offers

1. Upstream/Downstream Issues

[redacted]

2. Project Development Risks and Deployment Timing

[redacted]

REDACTED
Redacted

[redacted]

3. Price Volatility Mitigation

[redacted]

4. Contributions to Flexibility and Diversity

[redacted]

REDACTED
Redacted

[redacted]

REDACTED
Redacted

[redacted]

5. Contract Renewal Rights

[redacted]

6. Rate/Toll and Cost Sharing

[redacted]

[redacted]

7. Demand Charge Mitigation Opportunity

[redacted]

REDACTED
Redacted

[redacted]

8. Emissions Assessment

[redacted]

REDACTED

Redacted

[redacted]

9. Qualitative Assessment Conclusion

[redacted]

[redacted]

B. Quantitative Assessment

1. Landed Cost Analysis

[redacted]

REDACTED
Redacted

[redacted]

REDACTED

II. CONCLUSION

[redacted]

Estimated Delivered City-Gate Commodity Volumes & Percentages November 2023 through April 2024		
Supply Source	Delivered City-Gate Volumes	Percentage
Tennessee FS-MA Storage Path	384,490	4.1%
Empress Proposed Pipeline Path	292,979	3.1%
Union Dawn Storage Path	4,393,622	46.8%
Tennessee Niagara Pipeline Path	322,826	3.4%
Algonquin Receipts Pipeline Path	190,152	2.0%
Tennessee Long-Haul Pipeline Path	1,213,649	12.9%
Atlantic Bridge Ramapo Pipeline Path	1,041,040	11.1%
Iroquois Receipts Pipeline Path	947,681	10.1%
Peaking Contract 1	599,888	6.4%
Lewiston LNG	10,920	0.1%
Total Delivered Commodity Cost	9,397,248	100.0%

Estimated Delivered City-Gate Commodity Volumes & Percentages November 2024 through April 2025			
Supply Source	Delivered City-Gate Volumes	Percentage	Change in Percentage
Tennessee FS-MA Storage Path	373,333	4.0%	0.0%
Empress Pipeline Path	1,764,040	19.1%	16.0%
Union Dawn Storage Path	3,224,656	35.0%	-11.8%
Tennessee Niagara Pipeline Path	318,810	3.5%	0.0%
Algonquin Receipts Pipeline Path	188,901	2.0%	0.0%
Tennessee Long-Haul Pipeline Path	1,250,933	13.6%	0.7%
Atlantic Bridge Ramapo Pipeline Path	1,042,918	11.3%	0.2%
Iroquois Receipts Pipeline Path	942,199	10.2%	0.1%
Peaking Contract 1	65,055	0.7%	-5.7%
Lewiston LNG	49,242	0.5%	0.4%
Total Delivered Commodity Cost	9,220,087	100.0%	0.0%

Estimated Delivered City-Gate Commodity Volumes & Percentages May 2024 through October 2024		
Supply Source	Delivered City-Gate Volumes	Percentage
Empress Proposed Pipeline Path	1,371,796	56.1%
Atlantic Bridge Ramapo Pipeline Path	717,025	29.3%
TGP Zone 4 300 Leg Supply	209,998	8.6%
Tennessee Niagara Pipeline Path	51,464	2.1%
Dawn Supply	83,633	3.4%
Lewiston LNG	11,040	0.5%
Total Delivered Commodity Cost	2,444,956	100.0%

Estimated Delivered City-Gate Commodity Volumes & Percentages May 2025 through October 2025			
Supply Source	Delivered City-Gate Volumes	Delivered Cost per Dth	Change in Percentage
Empress Pipeline Path	1,724,276	64.7%	8.6%
Atlantic Bridge Ramapo Pipeline Path	516,236	19.4%	-9.9%
TGP Zone 4 300 Leg Supply	263,500	9.9%	1.3%
Tennessee Niagara Pipeline Path	54,840	2.1%	0.0%
Dawn Supply	93,218	3.5%	0.1%
Lewiston LNG	11,040	0.4%	0.0%
Total Delivered Commodity Cost	2,663,110	100.0%	0.0%

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-6:

Reference: Sept 17, 2024, filing

Does Northern have any plans that might result in serving RNG (with or without environmental attributes) or Hydrogen in the next 18 months? If yes, please describe and provide documentation if any.

Response:

Northern does not currently have any firm plans to incorporate RNG or hydrogen into its system in the next 18 months. Northern is aware of two developers who are exploring RNG facilities. These facilities could potentially interconnect into Northern's New Hampshire service territory in the future, but no interconnect agreements have been signed at this time. If RNG does flow into Northern's system, a developer or facility owner could sell the physical (brown) gas either to Northern or a retail supplier, but Northern has not discussed purchasing RNG from these developers.

Person Responsible: Francis Wells **Date:** 10/3/2024

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-7:

Reference: Sept 17, 2024, filing

Are Northern's hedging plans consistent with the prior year? Why or why not? What steps has Northern taken to manage the volatility of the gas market as compared to last year? Does Northern anticipate a similar shift in the gas market this year?

Response:

Northern's Price Risk Mitigation Plan has not changed from the Winter Period 2023-2024 to Winter Period 2024-2025, which is discussed beginning on Bates Page 000057. The objective of Northern's Price Risk Mitigation Plan 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.

Through the Price Risk Mitigation Plan, Northern targets 75 percent of its projected volumes from November through March be protected from changes in NYMEX prices. Average volatility of Henry Hub winter spot prices, calculated as the standard deviation of the percentage of price changes over the winter season, averaged 77% from the 2010-2011 through 2023-2024 winter seasons[1]. (See Bates page 000285.) Increasing exports of natural gas from North America, including LNG exports, may contribute to increased NYMEX natural gas price volatility, as NYMEX pricing is more likely to be influenced by global market forces. While NYMEX prices are currently relatively low, unanticipated geopolitical, weather, and financial events can affect both pricing levels and volatility. As such, Northern expects that there is potential for volatility in NYMEX pricing for the 2024-2025 Winter Period.

Northern also avoids exposure to spot New England prices due to the high prices and high volatility that has been observed in the New England index prices, such as Tennessee Zone 6 and Algonquin citygate delivered. Average volatility of Tennessee Zone 6 and Algonquin city-gate winter season spot prices averaged over 350% from 2010-2011 through 2023-2024. (See Bates page 000285.) The conditions that cause high pricing and high pricing volatility in New England are well-documented and ongoing. Specifically, during periods of cold weather, regional demands (including both natural gas LDC and power generation) exceed the available pipeline capacity into the region. Natural gas demands can be met with imported LNG, but such supplies need to

[1] Henry Hub is the delivery point for physical deliveries of the NYMEX natural gas futures contract.

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be contracted in advance of the winter period in order to assure availability. As such, Northern expects New England delivered pricing to continue to be volatile.

While Northern's hedging strategy has remained unchanged, changes to Northern's portfolio have resulted in a different mix of underground storage, fixed-price peaking supplies, and NYMEX locks for physical natural gas purchases.

Person Responsible: Francis Wells **Date:** 10/3/2024

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-8:

Reference: Sept 17, 2024, filing and Kahl Testimony at Bates 000009

Please explain the factors that, in the Company's opinion, are contributing to higher forecasted off-peak (Summer) rates compared to the average off-peak rates last season.

Response:

When COG rates were initially set for the 2024 Summer Season, they were higher than the currently proposed 2025 Summer COG rates. This was due, in part to, higher NYMEX prices. However, in early 2024, Summer Season NYMEX price began to fall. This decrease in NYMEX prices continued through the Spring and Summer months and resulted in a 2024 Summer COG rate that was lower than the proposed 2025 Summer COG rate. This is explained in greater detail on Page 28 of my testimony, Lines 7 through 16.

Person Responsible: Chris Kahl **Date:** 10/3/2024

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-9:

Reference: Sept 17, 2024, filing and Kahl Testimony at Bates 000017

Please describe Northern's "Simplified Market Based Allocation" (SMBA) method. How long has Northern been using this method. Has this method been updated or altered by the inclusion of Northern's RDAF? Why or why not?

Response:

Northern's use of the SMBA methodology predates the Company's acquisition by Unitil in 2008. The SMBA methodology allocates demand and commodity costs to all rate classes through a two-step process. The first step separates costs into base use and remaining use components. The second step allocates base and remaining use costs among the rate classes.

Base use costs for both demand and commodity components are derived by first separating out base use sendout from total use sendout which is calculated in Attachment NUI-CAK-3. Total base use demand costs are then separated from total demand costs by multiplying total base use sendout by the annual per unit pipeline capacity cost as shown in NUI-CAK Attachment 2. This amount is then divided into twelve even monthly amounts. Monthly base use commodity costs are determined by multiplying base use commodity sendout by monthly per unit pipeline costs as shown in NUI-CAK Attachment 6.

The allocation of baseload demand and commodity costs to each rate class is calculated by multiplying each rate classes' percentage of total baseload sendout by the monthly baseload demand and commodity cost.

To calculate remaining use (total use minus base use) commodity costs by rate class, monthly commodity costs are allocated to each rate class based on their total percentage of remaining use sendout (i.e. the difference between total monthly usage and monthly baseload usage). This percentage is then multiplied by the total remaining use commodity costs for each month. Base use and remaining use commodity costs are allocated to the rate classes in NUI-CAK-Attachment 8.

To calculate remaining use (total use less base use) demand costs by rate class, monthly usage is allocated to each rate class based on their percentage of total remaining use demand (i.e. the difference between design day use and daily base use). These percentages are then multiplied by each of type of demand cost and credit (e.g.

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storage, peaking, AMA credits) each month. The sum of the allocated costs for each type of demand resource (such as storage or peaking) equals the total remaining use demand costs. Base use and remaining use demand costs are calculated in NUI-CAK-Attachment 4.

Once baseload and remaining load costs are calculated for each resource, they are summed and then divided by that rate classes' projected seasonal demand in order to calculate the cost of gas charge. This is shown in Attachment NUI-CAK-Attachment 13.

The RDAF is totally independent from the cost of gas and has no impact on the calculation of cost of gas rates.

Person Responsible: Chris Kahl **Date:** 10/3/2024

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-10:

Reference: Sept 17, 2024, filing and Wells Testimony at Bates 000041

Please explain the 4% increase in the forecasted distribution deliveries for 2024-2025 season compared to the 2023-2024 weather-normalized actual sales as described in line 1 on Bates 000041. What are the factors behind this increase?

Response:

The primary driver for increase between 2023-24 and 2024-25 is related to the expected increase in consumption via our transportation customer G52 class following an increasing trend since 2017 and similarly the default service G52 class is expected to return to consumption rates similar to those prior to the COVID-19 pandemic. Although, no true forecast can be deterministic, these results also reflect the goal of ensuring adequate supply to customers in New Hampshire based on historical consumption and in these particular classes the forecast of employment in manufacturing (gathered from Moody's analytics) which is expected to increase over the next year. Please note that because the G52 class does not have strong correlation to weather effects, the weather normalization does not affect this class.

Person Responsible: Francis Wells **Date:** 10/3/2024

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-11:

Reference: Sept 17, 2024, filing and Kahl Testimony at Bates 000067

a. Please list the cost components of the Company's Gas Assistance Program (GAP). Please provide a description on how the GAP rate is calculated.

b. Kahl Testimony at Bates 000067, line 13 and 14 states, "As shown on Attachment NUI-SED-1 GAP, 14 Page 1 of 3, Line 12, total estimated costs are $367,985." Please confirm this calculated total estimated cost is correct and identify the schedule where it is located.

Response:

Please note that the referenced pages are From Demeris Testimony.

a. The GAP cost components are the discounts associated with the program and any prior period over/under collection. As shown on NUI-SED-1 GAP, the total estimated discounts, based on prior period participant counts and average use, plus the prior period over/undercollection, are divided by the forecasted therm sales in the rate period, November 1, 2024 – October 31, 2025, to calculate the proposed rate. This calculation is demonstrated on NUI-SED-1 GAP.

b. $367,895 is a typo. The correct subsidy is $368,045, NUI-SED-1 GAP, 14 Page 1 of 3, Line 12.

Person Responsible: S Elena Demeris **Date:** 10/3/2024

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-12:

Reference: Sept 17, 2024, filing

Please provide a description and relevant analysis on how the Empress Capacity Agreement is affecting the demand and supply costs of the forecasted rates for 2024-2025 COG season.

Response:

DOE 1-12 Attachment 1 CONFIDENTIAL provides a summary of total Northern supply costs for the 2024-2025 Annual Period.

City-Gate Commodity Costs ($), City-Gate Unit Commodity Cost ($/Dth), and City-Gate Volumes (Dth) data are derived from Attachment NUI-FXW-8.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Maximum City-Gate Volumes (Dth) are derived from Attachment NUI-FXW-15.

The Demand Cost (Net of NH and ME Capacity Assignment) ($) are calculated by taking the difference between the demand costs provided in Attachment NUI-FXW-5 and the New Hampshire capacity assignment demand revenue provided in Attachment NUI-FXW-6 and the Maine capacity assignment demand revenue.

Asset Management Revenue ($) is derived from page 6 of Attachment NUI-FXW-5. Please note that the Asset Management Revenue for the Empress Capacity Paths and Dawn Hub Storage Capacity Paths are allocated based on the total PNGTS MDQ of the two paths (12,500 Dth and 60,003 Dth, respectively). As discussed in response to DOE 1-13, a single asset management agreement covers these two capacity paths.

The Net Demand Cost ($) is the sum of the Demand Cost (Net of NH and ME Capacity Assignment) ($) and Asset Management Revenue ($). Net Demand Cost / Maximum City-Gate Volumes ($/Dth) are calculated by dividing the Net Demand Cost ($) by the Maximum City-Gate Volumes for each resource.

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[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The Total Cost ($) is calculated by summing the Net Demand Cost ($) and the City-Gate Unit Commodity Cost ($/Dth). City-Gate Total Unit Cost ($/Dth) is calculated by dividing the Total Cost by the City-Gate Volumes (Dth).

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Person Responsible: Francis Wells **Date:** 10/3/2024

REDACTED

2024-2025 Annual City Gate Cost, Delivered Volumes and Unit Cost - SALES SERVICE LOAD NORMAL YEAR
CURRENT Long-Term Portfolio

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost (Net of NH and ME Capacity Assignment) ($)	Asset Management Revenue ($)	Net Demand Cost ($)	Net Demand Cost / Maximum City-Gate Volumes ($/Dth)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]		636,833	757,270	84%	[redacted]					
2	Tennessee Long-Haul Pipeline Path			1,250,933	3,680,144	34%						
3	Empress Pipeline Path			3,488,317	3,496,828	100%						
4	Tennessee Niagara Pipeline Path			373,650	653,246	57%						
5	Algonquin Receipts Pipeline Path			188,901	456,615	41%						
6	Atlantic Bridge Ramapo Pipeline Path			1,559,154	2,105,320	74%						
7	Union Dawn Storage Path			3,317,874	17,131,693	19%						
8	Iroquois Receipts Pipeline Path			942,199	2,277,501	41%						
9	Lewiston LNG			60,282	75,000	80%						
10	Off-System Peaking / Incremental Supply			65,055	548,075	12%						
	Total Supplies - Including Off-System / Incremental Supply	$ 30,883,473	$ 2.599	11,883,197	31,181,693	38%	$ 61,369,719	$ (25,719,400)	$ 35,650,319	$ 1.143	$ 66,533,791	$ 5.599

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Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-13:

Reference: Sept 17, 2024, filing and Wells Testimony at Bates 000048 – 000049

The Testimony at Bates 000048-000049 outlines three changes to Northern's portfolio for the 2024-2025 period.

a. Is the additional 12,456 Dth of capacity mentioned in lines 6 – 9 on Bates 000048 representative of the annual, winter, or per day capacity allocation?

b. Does the change in Peaking Contract 1 mentioned in lines 14 – 19 on Bates 000048 reduce Northern's priority for receiving capacity during extreme weather events?

c. Does the change in Peaking Contract 2 mentioned in lines 21 – 25 on Bates 000048 reduce Northern's priority for receiving capacity during extreme weather events?

d. Please include a copy of all contracts and agreements in relation to the Empress Capacity Path, Peaking Contract 1, Peaking Contract 2, and the LNG Contract with Northeast Energy Center LLC ("NEC").

Response:

a. The Empress Capacity Path is capable of delivering 12,456 Dth per Day to Northern's system.
b. The performance obligation of Peaking Contract 1 is firm, as shown on page 13 of DOE 1-13 Attachment 1 CONFIDENTIAL, which is a copy of the transaction confirmation for Peaking Contract 1. Under the heading "Performance Obligation and Contract Quantity," the volume of 25,000 MMBtu/day Maximum is listed under "Firm (Variable Quantity)." The contract that Peaking Contract 1 replaces had the same performance obligation.
c. The performance obligation of Peaking Contract 2 is firm, as shown on page 16 of DOE 1-13 Attachment 1 CONFIDENTIAL, which is a copy of the transaction confirmation for Peaking Contract 1. Under the heading "Performance Obligation and Contract Quantity," the volume of 10,000 MMBtu/day Maximum is listed under "Firm (Variable Quantity)." The contract that Peaking Contract 2 replaces had the same performance obligation.
d. DOE 1-13 Attachment 1 CONFIDENTIAL provides the requested copies. Please note that Northern has entered an asset management agreement, which includes both the Empress Capacity Path and the Dawn Hub Storage Capacity Path.

Person Responsible: Francis Wells **Date:** 10/3/2024

ASSET MANAGEMENT TRANSACTION CONFIRMATION

Transaction Confirmation Date: March 13, 2024

Buyer:	Northern Utilities, Inc. ("**NUI**") Attention: Ann Hartigan 6 Liberty Lane West Hampton, NH 03842	**Seller:**	Emera Energy Services, Inc. ("**Emera**"); and Emera Energy Limited Partnership ("**EELP**") Attention: Natalie Davis 5151 Terminal Road Halifax, Nova Scotia B3J 1A1

Asset Management Arrangement:

This Transaction Confirmation is provided in accordance with the NAESB Base Contract for Sale and Purchase of Natural Gas made between NUI and Emera dated April 1, 2005, including the special provisions thereto and therefore constitutes a part of and includes all terms and conditions set forth in the Base Contract. Furthermore, for this Transaction Confirmation only, the provisions described herein shall be incorporated into the Base Contract. All other terms and conditions of the Base Contract dated shall remain in full force and effect as written.

This Transaction Confirmation (the "**AMA**") is an asset management arrangement, as defined by the Federal Energy Regulatory Commission ("**FERC**"), and shall be implemented in accordance's FERC's rules and regulations, including FERC Order Nos. 712, 712-A and 712-B ("**Order 712**"), and the FERC Gas Tariffs of each applicable Transporter. This asset management arrangement commences on April 1, 2024 and will terminate on March 31, 2025 (the "**Term**").

All transactions for Gas between EELP and NUI pursuant to this AMA (including the gas inventory transfers involving the Enbridge Dawn Storage Capacity, described below) will be on the same terms and conditions as the NAESB Base Contract for Sale and Purchase of Natural Gas made between NUI and Emera dated April 1, 2005, including the special provisions thereto.

The Performance Obligation under this AMA shall be Firm.

Capacity Releases:

NUI shall release for the Term the following Firm interstate transportation and storage capacity contracts (collectively, the "**Released Capacity**"), less the retail capacity assignments made to Maine and New Hampshire retail marketers pursuant to NUI's Maine and New Hampshire delivery service terms and conditions (the "**Retail Capacity Assignments**"), to EELP, except for the Portland Natural Gas Transmission System ("**PNGTS**") transportation capacity, which shall be released to Emera for the Term. NUI shall post the PNGTS Released Capacity in accordance with the applicable Transporter's FERC Gas Tariff and Order 712. NUI shall temporarily assign TransCanada Pipelines Limited ("**TCPL**") Released Capacity in accordance with TCPL's Gas Transportation Tariff, approved by the Canadian Energy Regulator. NUI shall temporarily assign Enbridge Gas Inc.("**Enbridge**") (formerly Union Gas Limited) Transportation Released Capacity in accordance with the M12 General Terms and Conditions, approved by the Ontario Energy Board. NUI shall temporarily assign Enbridge Dawn Storage Capacity in accordance with the terms of Enbridge Contract LST155.

Enbridge Dawn Storage Capacity

Company: Enbridge
Contract #: LST155
Primary Receipt Point and Primary Delivery Point: Enbridge Dawn Hub
Maximum Storage Balance ("MSB"): 6,330,336GJ (6,000,000Dth)
Maximum Daily Injection Demand ("MDID"):

(i) 0.75% of MSB (i.e., 47,478GJ/Day or 45,000Dth/Day), if then current balance in storage is less than 75% of MSB; and
(ii) 0.50% of MSB (i.e., 31,652GJ/Day or 30,000 Dth/Day), if then current balance in storage is greater than or equal to than 75% of MSB.

All Injections are on a Firm basis from December 1 through to and including September 30. All injections are on an Interruptible basis from October 1 through and including November 30.

Maximum Daily Withdrawal Demand ("MDWD"):

(i) In the Months of April 2024 and May, 2024, withdrawals are on an Interruptible basis; and
(ii) In the Month of June 1, 2024 through to and including March 31, 2025, Firm withdrawals up to:
    (a) 1.05% of MSB (i.e., 66,469 GJ/Day or 63,000Dth/Day), if then current balance is greater than or equal to 25% of MSB; and
    (b) 0.8% of MSB (50,643 GJ / 48,000Dth), if then current balance is less than 25% of MSB

The contract parameters above are taken from Schedule 1 of Contract LST155. In the event of any discrepancy, Schedule 1 of Contract LST155 shall govern.

Enbridge Transportation Capacity

Company: Enbridge
Contract #: M12256
Rate Schedule: M12
Primary Receipt Point: Dawn
Primary Delivery Point: Parkway
Maximum Daily Quantity: 42,962 GJ/Day (40,720 Dth/Day)

Company: Enbridge
Contract #: M12296
Rate Schedule: M12
Primary Receipt Point: Dawn
Primary Delivery Point: Parkway
Maximum Daily Quantity: 10,814 GJ/Day (10,250 Dth/Day)

Company: Enbridge
Contract #: M12279
Rate Schedule: M12
Primary Receipt Point: Dawn
Primary Delivery Point: Parkway
Maximum Daily Quantity: 10,875 GJ/Day (10,307 Dth/Day)

TCPL Transportation Capacity

Company: TCPL
Contract #: 57901
Rate Schedule: FT
Primary Receipt Point: Parkway
Primary Delivery Point: East Hereford
Maximum Daily Quantity: 35,872 GJ/Day (34,000 Dth/Day)

Company: TCPL
Contract #: 57055
Rate Schedule: FT

Primary Receipt Point: Parkway
Primary Delivery Point: East Hereford
Maximum Daily Quantity: 6,333 GJ/Day (6,003 Dth/Day)

Company: TCPL
Contract #: 63265
Rate Schedule: FT
Primary Receipt Point: Parkway
Primary Delivery Point: East Hereford
Maximum Daily Quantity: 10,569 GJ/Day (10,017 Dth/Day)

Company: TCPL
Contract #: 67167
Rate Schedule: FT
Primary Receipt Point: Parkway
Primary Delivery Point: East Hereford
Maximum Daily Quantity: 10,660 GJ/Day (10,104 Dth/Day)

Company: TCPL
Contract #: 71728
Rate Schedule: FT
Primary Receipt Point: Empress
Primary Delivery Point: East Hereford
Maximum Daily Quantity: 13,660 GJ/Day (12,890 Dth/Day)

PNGTS Transportation Capacity

Company: PNGTS
Contract #: 208543
Rate Schedule: FT
Primary Receipt Point: Pittsburg
Primary Delivery Point: Newington Granite
Maximum Daily Quantity: 40,003 Dth/Day

Company: PNGTS
Contract #: 233339
Rate Schedule: FT
Primary Receipt Point: Pittsburg
Primary Delivery Point: Newington Granite
Maximum Daily Quantity: 10,000 Dth/Day

Company: PNGTS
Contract #: 240520
Rate Schedule: FT
Primary Receipt Point: Pittsburg
Primary Delivery Point: Dracut
Maximum Daily Quantity: 10,000 Dth/Day

Company: PNGTS
Contract #: 284292
Rate Schedule: FT
Primary Receipt Point: Pittsburg
Primary Delivery Point: Dracut
Maximum Daily Quantity: 12,500 Dth/Day

(The Enbridge Transportation Capacity, TCPL Transportation Capacity, and the PNGTS Transportation Capacity are collectively known as the "**Transportation Assets**". The Enbridge Transportation Capacity and the TCPL Transportation Capacity are collectively known as the "**Canadian Transportation Assets**".) The PNGTS capacity with contract #208543 may be referred to as "**PNGTS C2C Capacity**", contract #233339 as "**PNGTS PXP Capacity**", contract #240520 as "**PNGTS WXP Capacity**" and contract #284292 as "**2023 PNGTS Open Season Capacity**". The Enbridge Transportation Capacity with contract #M12279, TCPL Transportation Capacity with contract #67167, and the PNGTS Transportation Capacity with contract #240520 may collectively be referred to as the "**WXP Capacity**".

NUI's Inventory:

NUI's inventory under this AMA shall be calculated by adding the starting storage balance transferred by NUI under this AMA plus Injection Volumes plus Inventory Transfer Volumes from NUI minus Inventory Transfer Volumes to NUI minus storage withdrawals nominated by NUI as set forth below in this AMA ("NUI's Inventory"). Emera and EELP shall not be obligated to match the physical inventory of the Enbridge Dawn Storage Capacity to NUI's Inventory except (i) the Enbridge Dawn Storage Capacity shall have actual physical inventory balance of 95% of the Released MSB by November 1, 2024 (and EELP shall send verification of the same to NUI once the relevant inventory transfers pursuant to the Retail Capacity Assignments have been completed for November 2024); and (ii) upon the completion of this AMA when all volumes remaining in NUI's Inventory are purchased by NUI. That notwithstanding, lack or surplus of physical inventory shall not be considered an excuse for failure of Emera or EELP to perform the Seller's obligations under this AMA.

Monthly Changes in Capacity Assignment:

The volume of the Released Capacity, including the Enbridge Dawn Storage Capacity and associated NUI's Inventory volumes, may change on a Monthly basis pursuant to the Retail Capacity Assignments. With respect to changes in the volume of the Enbridge Dawn Storage Capacity inventory (such changes shall be referred to as "**Inventory Transfer Volumes**"): (i) EELP agrees to sell, and NUI agrees to purchase, these Inventory Transfer Volumes when the net storage balance assigned to all retail marketers on NUI's system pursuant to the Retail Capacity Assignments increases; and (ii) EELP agrees to purchase, and NUI agrees to sell, these Inventory Transfer Volumes when the net storage balance assigned to all retail marketers on NUI's system pursuant to the Retail Capacity Assignments decreases. Such Monthly Inventory Transfer Volumes required by changes to the Retail Capacity Assignments will be priced at the weighted average cost of Gas as of the end of the Month immediately prior to the inventory transfer. As further described below, such purchases of Inventory Transfer Volumes by EELP will be repurchased by NUI as of April 1, 2025 in accordance with Section B, under the heading "Gas Nominations and Transactions", below.

Injection Portion of the Delivery Period:

On April 1, 2024, EELP will purchase NUI's April 1, 2024 beginning storage balance immediately after it sells such inventory to NUI as per the Asset Management Transaction Confirmation between Emera and NUI dated March 16, 2023 at a Contract Price of USD $2.596 per GJ.

The difference between the MSB assigned to EELP under this AMA (less the volume assigned pursuant to the Retail Capacity Assignments, referred to as the "**Released MSB**") and the beginning storage balance (such difference shall be referred to as the "**Injection Volume**") will be deemed to be injected on the following Monthly schedule (the Injection Volume can change Monthly throughout the injection period below, due to changes pursuant to the Retail Capacity Assignment):

Monthly Injection Volume:

Month	Monthly Injection Volume
April	(75% times Released MSB minus Beginning Storage Balance) divided by 4
May	(75% times Released MSB minus Beginning Storage Balance) divided by 4
June	(75% times Released MSB minus Beginning Storage Balance) divided by 4
July	(75% times Released MSB minus Beginning Storage Balance) divided by 4
August	12.50% times Released MSB
September	12.50% times Released MSB

EELP agrees that the deemed injection target end of month of NUI's Inventory for July 2024 is 75% and for September 2024 shall be 100% of the MSB, and EELP shall adjust the September 2024 Percentage Injection Volume to achieve this target, provided that such adjustment would not require injections in excess of the applicable MDID in which case the Percentage Injection Volume shall be adjusted to reflect the applicable MDID.

Contract Price Applicable to Injection Volume:

Each month's Injection Volume will be priced as described below:

[redacted]

Following each Month of the injection portion of the Term (i.e., April 2024 until September 2025), EELP or Emera (but not both) shall send a statement to NUI detailing the injection costs incurred by NUI during the applicable Month, and updating the weighted average cost of the NUI's Inventory. NUI shall not request injections into Enbridge Dawn Storage Capacity during the Months of October 2024 to March 2025.

Gas Nominations and Transactions:

A. From November 2024 through and including March 2025 (the "**Withdraw Period**"), NUI may nominate Daily storage withdrawals from the Enbridge Dawn Storage Capacity, or supply on remaining Transportation Capacity Assets as outlined in Section D, for deliveries to any primary or secondary delivery points on PNGTS ("**Delivery Point**"). Storage withdrawal nominations shall be made by 9:30 AM Eastern Prevailing Time ("**EPT**"), shall be made in accordance with the ICE's *Next Day Trading Calendar*, and may be non-ratable over weekends and holidays. Incremental intraday storage withdrawals will be scheduled on a commercially reasonable efforts basis, as will intraday reductions to storage withdrawals. EELP and Emera each acknowledge that reductions to storage withdrawals are made frequently by NUI for balancing, and NUI reserves the right to make nomination changes redirecting supply on PNGTS throughout the intraday cycles as well as for the 9 AM EPT morning cycle for the outgoing gas day, which requires that the asset manager be available to facilitate those nominations. Intraday changes are subject to the Enbridge, TCPL, and PNGTS nomination cycles, and operating conditions or restrictions.

REDACTED

In all cases, NUI shall have the right to reduce storage withdrawal volumes after making its daily storage withdrawal nomination on subsequent NAESB nomination cycles, subject to Elapsed Prorated Scheduled Quantity ("EPSQ"), NUI will be responsible for any imbalance or OFO penalties or charges incurred by NUI or Emera at the requested delivery meters only if the charges or penalties are the result of intraday changes explicitly requested by NUI.

B. [redacted]

C. The maximum daily quantities of the Enbridge Dawn Storage Capacity and the Transportation Assets being released or assigned to the asset manager will be equal to the volume of capacity that is remaining after the Retail Capacity Assignments. The currently released volumes for the Retail Capacity Assignments for February 2024 are:

(i) Enbridge Dawn Storage Capacity:
   a. MSB: 1,329,192 GJs/Day;
   b. MDWD: 13,957 GJs/Day; and
   c. MDID: 9,969 GJs/Day.

(ii) Enbridge Transportation Capacity: 13,574 GJs.
(iii) TCPL Transportation Capacity: 13,319 GJs (Parkway to E. Hereford); and 2,425 GJs (Empress to E. Hereford).
(iv) PNGTS Transportation Capacity: 8,399 Dth (#208543); 2,100 Dth (#233339); 2,100 Dth (#240520); and 2,229 Dth (#284292).

D. NUI has the right, but not the obligation, to call on the remaining Transportation Capacity Assets, after the Retail Capacity Assignments, for delivery to any PNGTS delivery point, up to the following volumes (in aggregate under this AMA) by Month:

Month	Up to Dth/Day
Apr-24	72,503
May-24	72,503
Jun-24	25,000
Jul-24	20,000
Aug-24	20,000
Sep-24	25,000
Oct-24	72,503
Nov-24	72,503
Dec-24	72,503
Jan-25	72,503
Feb-25	72,503
Mar-25	72,503

The Delivery Point of such volumes shall be any PNGTS delivery meter, as nominated by NUI.

REDACTED

Supply nominated during the months of April 2024 through October 2024 will utilize the Empress capacity path first, and then the Dawn capacity path. The first dispatch will be priced at [redacted] delivery points on PNGTS. Nominations shall be made by 9:30 AM Eastern Prevailing Time ("**EPT**"), shall be made in accordance with the ICE's *Next Day Trading Calendar*, and shall be ratable over weekends and holidays. The order of dispatch for NUI's nominated daily supply shall always exhaust the PNGTS C2C Capacity, followed by the PNGTS PXP Capacity, before the PNGTS WXP Capacity and the 2023 PNGTS Open Season Capacity.

E. During the months of April 2024 and October 2024, NUI shall baseload 4,000 Dth/Day. During the months of December 2024 through February 2025, NUI will baseload 7,500 Dth/day. Such baseload volumes will utilize the portion of TCPL Transportation Capacity K# 71728 (FT: Empress to E. Hereford) – 13,600 GJ (12,890 Dth) assigned to EELP and will be priced [redacted]

F. Daily supply nominated during the months of November 2024 through March 2025 will dispatch storage withdrawals, then any remaining Empress-based supply after fulfilling baseload volumes set forth in this Section, before Dawn-based non-storage supply. The pricing for storage withdrawals is outlined in Section B. The price for Empress-based daily supply nominations [redacted] NUI has the right, but not the obligation, to call on supply at this pricing structure in order to make up the difference between the MDWD and the MDQ of the Transportation Assets, up to 72,503 Dth/Day in aggregate nominations, including monthly baseload nominations in paragraphs D and E and daily nominations in this paragraph F. NUI may make daily nominations for deliveries to any primary or secondary delivery points on PNGTS. Nominations shall be made by 9:30 AM Eastern Prevailing Time ("**EPT**"), shall be made in accordance with the ICE's *Next Day Trading Calendar*, and shall be ratable over weekends and holidays.

G. If there is not adequate Enbridge and/or TCPL Released Capacity to make PNGTS deliveries as set forth above, then NUI shall have the right on any month beginning November 1, 2024 through and including March 31, 2025 to call upon additional Gas up to the unutilized portion of the maximum daily quantity of the PNGTS portion of the Released Capacity. [redacted]

REDACTED

[redacted] NUI shall make all nominations for delivery of Gas under this paragraph orally or in writing by 12:00 PM EPT on the Day of the New York Mercantile Exchange settlement Day prior to the first Day of the applicable Month.

H. NUI reserves the right to sell supply purchased under this AMA to parties on PNGTS at primary and/or secondary delivery points.

I. **AMA Fee:** [redacted]

J. **Operational Requirement:** NUI requires that the Emera be the party that transports PNGTS supply to the markets dispatched by NUI rather than passing NUI's points to a third party. Given this requirement, NUI will receive Emera's upstream contract number that corresponds with the PNGTS capacity released to them by NUI as the upstream ID. This will ensure that Emera manages confirmations rather than relying upon a third party to manage and communicate the status of confirmations.

K. NUI shall release the PNGTS Transportation Capacity to Emera for the Term at a $0.00/MMBtu demand cost. Canadian Transportation Assets and the Enbridge Dawn Storage Capacity shall be assigned to EELP, at the maximum demand rate, and NUI shall reimburse EELP for 100% of such demand rate charges. EELP shall pay all variable costs due to TCPL and Enbridge, and Emera shall pay all variable costs due to PNGTS. EELP shall pay all demand charges to Enbridge and TCPL, and NUI shall reimburse EELP in Canadian dollars. The Enbridge and TCPL variable, injection, withdrawal and fuel charges that are part of the Contract Price are subject to payment by NUI in United States dollars, and for that purpose Emera, EELP, and NUI agree to apply the Bank of Canada's Monthly Average of Exchange Rates for the Month of delivery.

Currently, with respect to the PNGTS C2C Capacity, subject to the C2C Negotiated Rate, deliveries to any of the following points along the Joint Facilities will not incur incremental commodity charges per the PNGTS Tariff:

Meter#	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-1241	South Berwick	Granite State
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

Deliveries on the PNGTS C2C Capacity to delivery points not listed immediately above will incur an incremental commodity charge, currently equal to $0.2543/Dth. This incremental charge is subject any change in the Recourse Reservation Rate, applicable to PNGTS Rate Schedule FT. This incremental commodity charge could be incurred by NUI as a result of requests for delivery to points not listed above, or could be incurred by Emera as a result of its own optimization activity under this AMA. NUI shall pay Emera for any incremental charges that result from NUI's requests for deliveries to points not listed above.

Currently, with respect to the PNGTS PXP Capacity, deliveries to any of the following points along the Joint Facilities will not incur incremental commodity charges per the PNGTS Tariff:

Meter#	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
05-1241	South Berwick	Granite State
05-0725	Eliot	Granite State
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1150	Dracut	Tennessee Gas Pipeline

Subject to the Negotiated Rate, Deliveries using the PNGTS PXP Capacity to any PNGTS point that is not included on the list above and/or receipts from any point other than the primary receipt at Pittsburg, NH will incur an incremental commodity charge equal to the PNGTS system daily recourse rate of $0.8543 per Dth, minus the PXP Negotiated Daily Demand Rate, which is $0.7448 per Dth. This commodity charge could be incurred by NUI as a result of requests for delivery to points that are not located on that list or it could be incurred by Emera as a result of its own optimization activity under this AMA. NUI shall pay Emera for any incremental commodity charges that are the result of NUI's requests for deliveries to points not listed above. This incremental charge is subject any change in the Recourse Reservation Rate, applicable to PNGTS Rate Schedule FT. PNGTS PXP Capacity is also subject to a $0.0091 per Dth usage (commodity) charge regardless of delivery point, the Measurement Variance on PNGTS and the fuel charges that are applicable to PXP Phase III.

PNGTS WXP Capacity and the 2023 PGNTS Open Season Capacity are subject to a Discounted Daily Demand Rate, which is applicable to all receipt and delivery points on PNGTS. As such, deliveries on PNGTS using the WXP Capacity or the 2023 Open Season Capacity, to any primary or secondary points on PNGTS will incur no incremental commodity charges. However, deliveries using WXP Capacity or 2023 PGNTS Open Season Capacity on PNGTS are subject to both Measurement Variance on PNGTS and the fuel charges that are applicable to the WXP Capacity and the 2023 PGNTS Open Season Capacity.

L. Demand Credits. In the event that there is an outage that occurs on the Transportation Assets and demand credits are potentially available, it is incumbent upon Emera to coordinate with NUI to nominate the supply in accordance with the Transporter's tariff(s) which are impacted in order to make NUI eligible for demand credits.

M. Retroactive Adjustments. In the event that any of the Transporters' applicable transportation charges are changed retroactively and either Emera or NUI receive an invoice reflecting such change, then the party entitled to receive the resulting credit or responsible to pay the additional amount, as the case may be, shall do so. In each case, the party entitled to receive or responsible to pay shall be the party ultimately responsible for the payment of such transportation charges under this Transaction Confirmation at the time to which such retroactive invoice applies. If a party receives such a retroactive invoice, it shall provide it to the other party, along with supporting documentation. An example of a retroactive change to transportation charges includes, but is not limited to, changes in the incremental commodity charges to deliver to points not listed in Section K herein.

N. Emera shall be responsible for the administration and payment of all import/export filings, duties, taxes, and any other miscellaneous charges associated with transporting the volumes above from the applicable Receipt Point to NUI at the Delivery Point on the PNGTS Transportation Capacity. NUI will be responsible for applicable taxes that may be assessed in connection with the Enbridge Dawn Storage Capacity. In the case of inventory transfers that may occur due to changes in retail marketer assignments, the purchaser of the inventory transfer volume (i.e., either EELP or NUI, as the case may be) shall be responsible for applicable taxes. The retail marketers taking transportation and storage capacity pursuant to the Retail Capacity Assignments will be responsible for their own administration and payment of all import/export filings, duties, taxes, and any other miscellaneous charges associated with their share of these assets (the "**Retail Marketer Tax Obligations**"), and NUI agrees to indemnify and hold harmless Emera and EELP for any costs or liabilities whatsoever that Emera or EELP may incur (if any) with respect to such Retail Marketer Tax Obligations.

Dodd-Frank Representations:

Each party represents that (a) it regularly makes or takes delivery of the commodity(ies) that are the subject of this transaction in the ordinary course of its business; and (b) for the purpose of 17 CFR 32.3, it is a producer, processor or commercial user of, or a merchant handling the commodity or commodities that is/are the subject of any commodity option transactions, if any, entered into hereunder, or the products or by-products thereof, and is offering (or being offered, as the case may be) or entering into such transactions solely for purposes related to its business as such. The parties confirm their intention that any such commodity option transactions be physically settled, such that if exercised, they result in the sale of an exempt commodity for either immediate or deferred shipment or delivery.

Early Termination:

NUI shall have the right to terminate this Transaction Confirmation in the event that Emera fails to deliver for a period of three consecutive days, unless such failure is excused by either Force Majeure, or the Released Capacity is otherwise curtailed regardless of whether such curtailment is the result of Force Majeure, provided that curtailment in this circumstance is not due to the reliance by Emera or EELP on alternate or secondary receipt points (unless such reliance is pursuant to the paragraph labelled, "Alternate Supplies"). Such right is a Termination Option, pursuant to Section 3.4 of the Base Contract. In the event that this Termination Option is exercised, damages for non-performance shall be calculated in the manner prescribed in Section 3.2 of the Base Contract and liquidation costs will be calculated in the manner prescribed in Section 10.3.1 of the Base Contract.

For the purposes of this Transaction Confirmation, the term, "Contract Value," as defined in Section 10.3.1 of the Base Contract, shall include any remaining AMA Fee to be paid by Emera as of the Early Termination Date. For the purposes of this AMA, the term, "Market Value," as defined in Section 10.3.1 shall include the value of the asset management fee for any replacement asset management agreement that NUI enters in a commercially reasonable manner in respect of the Released Capacity or a portion thereof, pro-rated to the remaining Term of this Transaction Confirmation.

In the event of Early Termination of this Transaction Confirmation (whether due to NUI's exercise of the Termination Option or due to either party exercising its right to early terminate under the Base Contract), (1) NUI shall promptly recall all Released Capacity, (2) NUI shall purchase and Emera shall sell any remaining NUI's Inventory at the at the weighted average price of the NUI's Inventory at the time of Early Termination and (3) if either EELP or Emera is the Defaulting Party, then NUI shall have the right to net or aggregate, as appropriate, any and all amounts owing between NUI and both of Emera and EELP into a single Net Settlement Amount owed to or from NUI, and if NUI is the Defaulting Party, then Emera shall net or aggregate, as appropriate, any and all amounts owing between NUI and both of Emera and EELP into a single Net Settlement Amount owed to or from Emera.

Alternate Supplies:

In the event that NUI's capacity is curtailed due to a Force Majeure or pipeline restrictions, the asset manager must be willing to fill the curtailed capacity with an alternate supply source, if available using commercially reasonable efforts, in order to bypass restrictions that impacted the original nomination path. Any alternate supply will be at a mutually agreed upon price plus variables to the requested delivery point.

Further Assurances, Conflicts:

The parties will use commercially reasonable efforts to enter into such agreements and documents with each of Enbridge, TCPL, and PNGTS and do all such further actions, as may be required of each party in order to effect the releases and assignments contemplated hereby. In the event of a conflict between the terms of this Transaction Confirmation and the terms of any such agreement or document (e.g., temporary assignment agreements with Enbridge), then as between the parties, the provisions of this Transaction Confirmation shall prevail.

[Signature page follows.]

ACCEPTED AND AGREED TO BY:

EMERA ENERGY SERVICES, INC.

A. Michael Burnell

Name: A. Michael Burnell
Title: President

March 18, 2024

Date:

NORTHERN UTILITIES, INC.

Joseph Conneely

Name: Joseph Conneely
Title: Vice President

3/13/2024

Date:

EMERA ENERGY LIMITED PARTNERSHIP
By its general partner
EMERA ENERGY GENERAL PARTNER INC.

Judy Steele

Name: Judy Steele
Title: President & COO

March 19, 2024

Date:

REDACTED

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

REPSOL	**Date: January 22, 2024** **Buyer's Transaction Confirmation #:** **Seller's Transaction Confirmation #:**

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated December 15, 2010 as amended.

SELLER: Repsol Energy North America Corporation 2455 Technology Forest Blvd. The Woodlands, TX 77381 Attn: Karen Iampen Phone: (832) 442-1040 Email: karen.iampen@repsol.com Base Contract No. 100352 Transporter: Emera Brunswick Pipeline Company Ltd. (**"EBP"**); Maritimes & Northeast Pipeline, L.L.C. (**"M&NP"**); and Portland Natural Gas Transmission System (**"PNGTS"**) Transporter Contract Number: ______	**BUYER:** Northern Utilities, Inc. 6 Liberty Lane West Hampton, NH 03842-1720 Attn: Ann Hartigan Email: hartigan@unitil.com Phone: 603-773-6430 Fax: 603-773-6647 Base Contract No. ______ Transporter: ______ Transporter Contract Number: ______

[redacted]

Delivery Period & Winter Delivery Period: The "**Delivery Period**" shall commence November 1, 2024 and end October 31, 2029. The **"Winter Delivery Period**" shall be each successive five-month period from November through March during the Delivery Period.

Winter Delivery Period 1:	Begin: November 1, 2024	End: March 31, 2025
Winter Delivery Period 2:	Begin: November 1, 2025	End: March 31, 2026
Winter Delivery Period 3:	Begin: November 1, 2026	End: March 31, 2027
Winter Delivery Period 4:	Begin: November 1, 2027	End: March 31, 2028
Winter Delivery Period 5:	Begin: November 1, 2028	End: March 31, 2029

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
____MMBtus/day Minimum ☐ EFP	Up to ______ MMBtus/day [redacted] (**"Maximum Daily Quantity"** or **"MDQ"**) subject to Section 4.2. at election of	__0__ MMBtus/day

REDACTED

ξ Buyer or ☐ Seller
Subject to Special Conditions 1 and 2 below.

Delivery Point(s): The Delivery Point(s) shall be, at Buyer's option, any one or combination of the following:

(i) M&NP US Meter 30028 Cotton Rd.;
(ii) PNGTS Meter 05-0600 Westbrook GS and/or M&NP US Meter 30005;
(iii) PNGTS Meter 05-0850 Newington GS; or
(iv) PNGTS Meter (51241) South Berwick, ME GS and/or M&NP US Meter 30056.

Special Conditions:

1) On any Day during the Delivery Period, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ. The MDQ shall equal [redacted]f Gas and, for each Winter Delivery Period, the Winter Contract Quantity ("**WCQ**") shall equal [redacted]of Gas. The WCQ is non-must take. Volumes may be taken non-ratably on weekends and holidays.

2) During each Winter Delivery Period, Buyer shall have the right to nominate to Seller a daily quantity of Gas to be sold and delivered on the applicable Day of the Winter Delivery Period [redacted] inclusive, but not to exceed the WCQ cumulatively for all Days of the applicable Winter Delivery Period. Buyer shall nominate to Seller [redacted]on [redacted] pursuant to the Intercontinental Exchange, Inc. ("**ICE**") Trading Hours Holiday Calendar. After Buyer's initial nomination for a Day made in accordance with the preceding sentence, Buyer may decrease or increase the quantity to be delivered on the Day upon giving Seller [redacted]advance notice of the change, provided that (i) such change does not cause Buyer to exceed the MDQ for the Day or the WCQ cumulatively for all Days of the applicable Winter Delivery Period, and (ii) the change is recognized and effectuated by Seller's and Buyer's Transporters in accordance with their nomination protocols, operating procedures, and conditions of service.

The quantity of Gas [redacted] by Buyer in accordance with the preceding sentences for a Day shall be the Contract Quantity for the applicable Day (including for purposes of Section 3.2 of the Base Contract) and shall be delivered by Seller and taken by Buyer on a Firm basis on the applicable Day. As a clarification, no Gas will be sold and delivered hereunder during any Months of the Delivery Period that are not part of a Winter Delivery Period even though Monthly Demand Charges will be due and payable for such Months.

3) Subject to Special Condition 4 below, for each Year in the Delivery Period, Buyer will pay to Seller an amount equal to [redacted] due on the payment due date as specified in Section 7.2 of the Base Contract for the applicable Month. The Annual Demand Charge shall be assessed notwithstanding the actual quantity of Gas nominated by Buyer for each Day in such Month of each Year in the Delivery Period. The parties agree that for the purposes of Section 10.3 of the Base Contract, the net present value of the [redacted]

4) [redacted]in accordance with the provisions herein. Upon giving Seller advance written Notice at least two years prior to April 1st of a given Year, [redacted] The increased MDQ and WCQ will go into effect on the effective date selected by Buyer in accordance with the preceding sentence and shall remain in effect during the remainder of the Delivery Period. Further, the Annual Demand Charge shall be increased to maintain the current ratio o[redacted] The parties will execute an amendment to this Transaction Confirmation to reflect any elected increase in the MDQ and WCQ and the corresponding increase to the Annual Demand Charge.

5) <u>Source of Gas</u>. [redacted] Seller may, but is not obligated to, source the Gas delivered hereunder from other sources.

6) <u>Termination Rights</u>. [redacted] From and after such termination, neither party shall have any further rights or obligations under this transaction and Transaction Confirmation, except that any rights or obligations that relate or pertain to the period prior to the effective date of the termination shall survive such termination, including, without limitation, payment obligations for Gas delivered or to be delivered prior to the effective date of the termination or for Monthly Demand Charges that relate to the period prior to the effective date of the termination. A termination effected pursuant to this Special Condition shall not be considered a termination for an Event of Default pursuant to Section 10 of the Base Contract between Seller and Buyer.

7) Buyer represents to Seller that the embedded volumetric optionality in the transaction is primarily intended by it as of the execution of the transaction to address physical factors or regulatory requirements that reasonably influence demand for, or supply of, Gas.

Seller: Repsol Energy North America Corporation	Buyer: Northern Utilities, Inc.
By:	By: Joseph Conneely
Title: SVP Global Trading and Commercialization of LNG and Nat Gas	Title: VP, Energy Supply
Date: 02/20/2024	Date: February 16, 2024

REDACTED

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

REPSOL		**Date: January 29, 2024** **Buyer's Transaction Confirmation #:** **Seller's Transaction Confirmation #:**

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated December 15, 2010 as amended.

SELLER:	**BUYER:**
Repsol Energy North America Corporation	Northern Utilities, Inc.
2455 Technology Forest Blvd.	6 Liberty Lane West
The Woodlands, TX 77381	Hampton, NH 03842-1720
Attn: Karen Iampen	Attn: Ann Hartigan
Phone: (832) 442-1040	Email: hartigan@unitil.com
Email: karen.iampen@repsol.com	Phone: 603-773-6430
Base Contract No. 100352	Fax: 603-773-6647
Transporter: Emera Brunswick Pipeline Company Ltd. ("**EBP**"); Maritimes & Northeast Pipeline, L.L.C. ("**M&NP**"); and Portland Natural Gas Transmission System ("**PNGTS**")	Base Contract No.
Transporter Contract Number:	Transporter:
	Transporter Contract Number:

[redacted]

Delivery Period & Winter Delivery Period: The "**Delivery Period**" shall commence November 1, 2024 and end October 31, 2029. The "**Winter Delivery Period**" shall be each successive five-month period from November through March during the Delivery Period.

Winter Delivery Period 1:	Begin: November 1, 2024	End: March 31, 2025
Winter Delivery Period 2:	Begin: November 1, 2025	End: March 31, 2026
Winter Delivery Period 3:	Begin: November 1, 2026	End: March 31, 2027
Winter Delivery Period 4:	Begin: November 1, 2027	End: March 31, 2028
Winter Delivery Period 5:	Begin: November 1, 2028	End: March 31, 2029

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
______ MMBtus/day	Up to ______ MMBtus/day	0 MMBtus/day
Minimum	[redacted]	
☐ EFP	("**Maximum Daily Quantity**" or "**MDQ**")	
	subject to Section 4.2. at election of	

REDACTED

ξ Buyer or ☐ Seller
Subject to Special Conditions 1 and 2 below.

Delivery Point(s): The Delivery Point(s) shall be, at Buyer's option, any one or combination of the following:

(i) M&NP US Meter 30028 Cotton Rd.;
(ii) PNGTS Meter 05-0600 Westbrook GS and/or M&NP US Meter 30005;
(iii) PNGTS Meter 05-0850 Newington GS; or
(iv) PNGTS Meter (51241) South Berwick, ME GS and/or M&NP US Meter 30056.

Special Conditions:

1) On any Day during the Delivery Period, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ. The MDQ shall equal [redacted] of Gas and, for each Winter Delivery Period, the Winter Contract Quantity ("**WCQ**") shall equal [redacted] of Gas. The WCQ is non-must take. Volumes may be taken non-ratably on weekends and holidays.

2) During each Winter Delivery Period, Buyer shall have the right to nominate to Seller a daily quantity of Gas to be sold and delivered on the applicable Day of the Winter Delivery Period [redacted] inclusive, but not to exceed the WCQ cumulatively for all Days of the applicable Winter Delivery Period. Buyer shall nominate to Seller [redacted] on [redacted] pursuant to the Intercontinental Exchange, Inc. ("**ICE**") Trading Hours Holiday Calendar. After Buyer's initial nomination for a Day made in accordance with the preceding sentence, Buyer may decrease or increase the quantity to be delivered on the Day upon giving Seller at [redacted] advance notice of the change, provided that (i) such change does not cause Buyer to exceed the MDQ for the Day or the WCQ cumulatively for all Days of the applicable Winter Delivery Period, and (ii) the change is recognized and effectuated by Seller's and Buyer's Transporters in accordance with their nomination protocols, operating procedures, and conditions of service.

   The quantity of Gas [redacted] by Buyer in accordance with the preceding sentences for a Day shall be the Contract Quantity for the applicable Day (including for purposes of Section 3.2 of the Base Contract) and shall be delivered by Seller and taken by Buyer on a Firm basis on the applicable Day. As a clarification, no Gas will be sold and delivered hereunder during any Months of the Delivery Period that are not part of a Winter Delivery Period even though Monthly Demand Charges will be due and payable for such Months.

3) For each Year in the Delivery Period, Buyer will pay to Seller an amount equal to [redacted] due on the payment due date as specified in Section 7.2 of the Base Contract for the applicable Month. The Annual Demand Charge shall be assessed notwithstanding the actual quantity of Gas nominated by Buyer for each Day in such Month of each Year in the Delivery Period. The parties agree that for the purposes of Section 10.3 of the Base Contract, the net present value of the [redacted]

4) Source of Gas. [redacted] Seller may, but is not obligated to, source the Gas delivered hereunder from other sources.

5) Termination Rights. [redacted] From and after such termination, neither party shall have any further rights or obligations under this transaction and Transaction Confirmation, except that any rights or obligations that relate or pertain to the period prior to the effective date of the termination shall survive such termination, including, without limitation, payment obligations for Gas delivered or to be delivered prior to the effective date of the termination or for Monthly Demand Charges that relate to the period prior to the effective date of the termination. A termination effected pursuant to this Special Condition shall not be considered a termination for an Event of Default pursuant to Section 10 of the Base Contract between Seller and Buyer.

6) Buyer represents to Seller that the embedded volumetric optionality in the transaction is primarily intended by it as of the execution of the transaction to address physical factors or regulatory requirements that reasonably influence demand for, or supply of, Gas.

Seller: Repsol Energy North America Corporation	Buyer: Northern Utilities, Inc.
By:	By: Joseph Conneely
Title:	Title: VP Energy Supply
Date: 02/20/2024	Date: February 16, 2024

REDACTED

Transaction Confirmation

Northeast Energy Center LLC	Date: April 11, 2024________________ ___, Transaction Confirmation #: ______________

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated April 11 , 2024. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER: Northeast Energy Center LLC 100 Front Street, #900, West Conshohocken, PA 19428 Attn: Liqun Pan Phone: 832-646-8898 Fax: ______________ Base Contract No. ______________ Transporter: ______________ Transporter Contract Number: ______________	**BUYER:** Northern Utilities, Inc. 6 Liberty Lane West, Hampton, NH 03842-1720 Attn: Ann Hartigan Phone: 603.773.6430 Fax: 603.773.6630 Base Contract No. ______________ Transporter: ______________ Transporter Contract Number: ______________

Contract Price: The Buyer shall pay the following prices for service under this Transaction Confirmation:

1. Fixed Charge:[redacted]onth
2. Liquefaction Charge: [redacted] per MMBtu, applied to the net volume of Gas that is liquefied up to firm quantity. This price is shall be adjusted by the annual inflation rate using the Producer Price Index, as of April 1 of each Year (defined as April 1 through March 31 after Year 1 of the Delivery Period) (based on the publication by the US Bureau of Labor Statistics, under "Final Demand – Unadjusted 12 Month Percent Change").
3. Normal operations for the Seller's LNG truck loading rack are defined as 7:00 AM to 5:00 PM each Business Day. Seller reserves the right to assess a [redacted] per MMBtu surcharge for weekend, afterhours or holiday LNG truck loading.
4. Carryover Inventory: Should the Buyer not use all [redacted] MMBtus in a given Year, such volume minus boiloff will Carryover to the next Year. In such instances, Buyer shall only schedule liquefaction volumes for the difference between [redacted] Dth and Buyer's remaining inventory as of March 31 of the subsequent Year. Buyer will still pay the [redacted]per MMBtu Liquefaction Charge for the Carryover Volume.
5. No boiloff or reduction shall apply to the Firm Contract Quantity for any reason from November through March each Year of the Delivery Period. Buyer shall have [redacted] Dth of inventory available on November 1 of each Year of the Transaction Confirmation, except in the case that the Buyer had not delivered sufficient Gas to the Liquefaction Delivery Point in which case the inventory shall be reflective of the actual volume liquefied on the Buyer's account.
6. Upon termination of the Transaction Confirmation, Buyer shall use reasonable best efforts to utilize all Firm Contract Quantity. To the extent that there is remaining volume, Buyer shall sell such volumes to Seller at a mutually agreeable price.

Delivery Period: Year 1: Date of Transaction Confirmation through March 31, 2025
Year 2 through Year 5: April 1, 2025 through March 31, 2029

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
______ MMBtus LNG /year	0 MMBtus/year Minimum	Up to ______ MMBtus/day
☐ EFP	[redacted] MMBtus/year Maximum	
	subject to Section 4.2. at election of	
	x Buyer or ☐ Seller	

Delivery Point(s):

Liquefaction Delivery Point: Gas to be liquified shall be delivered by Buyer to Seller's interconnection with Tennessee Gas Pipeline at Cady Brook meter 55669, using Buyer's own pipeline transportation capacity.

REDACTED

LNG Truck Loading Delivery Point: Buyer shall take delivery of LNG at the Seller's truck loading rack at the Seller's facility at 304 Southbridge Road, Charlton, MA 01507.
Special Conditions: Buyer shall deliver [redacted] of Gas volume to be liquefied to Seller during the months of April through October each year of the Delivery Period (excluding Plant outage days). Daily nomination for less than [redacted] MMBtus shall only occur on Seller's normal operating/liquefaction days. Buyer shall be responsible for arranging Gas supply to be delivered for liquefaction. Seller shall store LNG for Buyer up to [redacted] MMBtu. Buyer shall notify Seller estimated liquefaction schedule for the first contract year volume upon contract execution. Maximum 3 Trucks loading per day guaranteed; additional trucking request subject to Seller availability. Buyer shall provide 48-hour notice for scheduling of LNG trucks. Seller shall use best efforts for short notice LNG truck loading to provide operational flexibility within the 48-hour scheduling window. Buyer shall be responsible for arranging LNG trucking from the Seller's truck loading rack at the Seller's facility. This Transaction Confirmation shall extend from year to year after the end of the Delivery Period, unless terminated by either party with a minimum of 12 (twelve) months advance written notice prior to the last day of the Delivery Period or, if extended, the anniversary date thereof. Upon the end of the Delivery Period, the Fixed Charge shall be adjusted by the annual inflation rate using the Producer Price Index, as of April 1 of each Year (defined as April 1 through March 31 after Year 1 of the Delivery Period) (based on the publication by the US Bureau of Labor Statistics, under "Final Demand – Unadjusted 12 Month Percent Change").

Seller: Matthew Taylor	Buyer: Joseph Conneely
By: Matthew Taylor	By: Joseph Conneely
Title: Director	Title: VP, Energy Supply
Date: 4/17/2024	Date: 4/17/24

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-14:

Reference: Sept 17, 2024, filing and Wells Testimony at Bates 000049 – 000050

Please provide a copy (with all attachments) of any amendments made to the following agreements:

a. Gas Transportation Contract for Firm Transportation Service between Portland Natural Gas Transmission System and Northern utilities, Inc. dated August 22, 2023;

b. 2024 Precedent Agreement between TransCanada Pipelines Limited and Northern Utilities, Inc. dated August 21, 2023;

c. Firm Transportation Service Contract between TransCanada Pipelines Limited and Northern Utilities, Inc. dated August 21, 2023; and

d. Precedent Agreement between Northern Utilities, Inc, and TransCanada Pipelines Limited dated August 21, 2023.

If these amendments have already been provided to the PUC and DOE in a different docket, (in redacted and confidential format) please identify the docket and the filing date in lieu of providing a copy.

Response:

a. The Gas Transportation Contract for Firm Transportation Service between Portland Natural Gas Transmission System and Northern utilities, Inc. dated August 22, 2023 was provided as Attachment 2 to the Empress Capacity Resource Assessment in Docket No. DG 23-087 on October 5, 2023. This agreement has not been amended.
b. The 2024 Precedent Agreement between TransCanada Pipelines Limited and Northern Utilities, Inc. dated August 21, 2023 was provided as Attachment 4 to the Empress Capacity Resource Assessment in Docket No. DG 23-087 on October 5, 2023. This agreement has not been amended.
c. The Firm Transportation Service Contract between TransCanada Pipelines Limited and Northern Utilities, Inc. dated August 21, 2023 was provided as Attachment 5 to the Empress Capacity Resource Assessment in Docket No. DG 23-087 on October 5, 2023. An amendment to this agreement was filed in

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Docket No. DG 23-087 on July 1, 2024 and served on the service list in that docket.

d. The Precedent Agreement between Northern Utilities, Inc, and TransCanada Pipelines Limited dated August 21, 2023 was provided as Attachment 6 to the Empress Capacity Resource Assessment in Docket No. DG 23-087 on October 5, 2023. An amendment to this agreement was filed in Docket No. DG 23-087 on July 1, 2024 and served on the service list in that docket.

Person Responsible: Francis Wells **Date:** 10/3/2024

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-15:

Reference: Sept 17, 2024, Filing and Demeris Testimony at Bates 000074

Demeris Testimony at Bates 000074 lines 9 – 11, states "Please note that all bill impacts include the RDAC charges proposed for effect November 1, 2024, filed on or before September 17th under separate docket.

Please provide a recalculation of all bill impacts without the RDAC charges proposed for effect November 1, 2024, filed on or before September 17th under a separate docket, Dkt# DG 24-103.

Response:

Please see DOE 1-15 Attachments for the requested information. As shown, holding the currently effective RDAC constant, the impact to Residential Heating customers during the winter period is a decrease of ($29.64) or -3.0%. The impact to residential Non-Heating customers in the winter period is ($6.95) or -1.8%. Winter bill impacts for the C&I classes are decreases ranging from -0.95% to -3.91%.

Summer impacts are Residential Heat, an increase of $0.59 or 0.3%; Residential Non-Heat: an increase of $0.30 or 0.13% and increases to C&I customers ranging from 2.06% to 6.42%.

Person Responsible: S Elena Demeris **Date:** 10/3/2024

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill
Comparison of Summer 2025 vs. Summer 2024

				May	June	July	August	Sept	October	Summer
1				**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**
2	Typical Usage: therms(*)			38	15	12	12	11	17	105
3	**Summer 2025**									
4	Customer Charge	units @	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20
5	All	units @	$0.9259	$34.86	$13.75	$11.05	$10.91	$10.60	$16.15	$97.32
6	All	RDAC	$0.1071	$4.03	$1.59	$1.28	$1.26	$1.23	$1.87	$11.26
7		Total Base Rates	$1.0330	$38.90	$15.34	$12.33	$12.17	$11.82	$18.01	$108.58
8		COG 1	$0.3884	$14.63						$14.63
9		COG 2	$0.3884		$5.77					$5.77
10		COG 3	$0.3884			$4.64				$4.64
11		COG 4	$0.3884				$4.58			$4.58
12		COG 5	$0.3884					$4.45		$4.45
13		COG 6	$0.3884						$6.77	$6.77
14		Summer Period Avg. COG	$0.3884 *							
15		LDAC	$0.0649	$2.44	$0.96	$0.77	$0.76	$0.74	$1.13	$6.82
16			**TOTAL**	$78.17	$44.27	$39.94	$39.71	$39.21	$48.12	**$289.42**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
19	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
20	COG Change		**$ Change**	$1.19	$0.47	$0.38	$0.37	$0.36	$0.55	**$3.31**
21			**% Change**	1.52%	1.06%	0.94%	0.94%	0.92%	1.14%	**1.15%**
21	LDAC Change		**$ Change**	($0.98)	($0.38)	($0.31)	($0.31)	($0.30)	($0.45)	**($2.72)**
22			**% Change**	-1.25%	-0.87%	-0.78%	-0.77%	-0.76%	-0.94%	**-0.94%**
23				**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**
24	Typical Usage: therms			38	15	12	12	11	17	105
25	**Summer 2024**									
26	Customer Charge	units @	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20
27	All	units @	$0.9259	$34.86	$13.75	$11.05	$10.91	$10.60	$16.15	$97.32
28	All	RDAC	$0.1071	$4.03	$1.59	$1.28	$1.26	$1.23	$1.87	$11.26
29		Total Base Rates	$1.0330	$38.90	$15.34	$12.33	$12.17	$11.82	$18.01	$108.58
30		COG 1	$0.3569	$13.44						$13.44
31		COG 2	$0.3569		$5.30					$5.30
32		COG 3	$0.3569			$4.26				$4.26
33		COG 4	$0.3569				$4.20			$4.20
34		COG 5	$0.3569					$4.08		$4.08
35		COG 6	$0.3569						$6.22	$6.22
36		Summer Period Avg. COG	$0.3569 *							
37		LDAC	$0.0908	$3.42	$1.35	$1.08	$1.07	$1.04	$1.58	$9.54
38			**TOTAL**	$77.96	$44.19	$39.88	$39.64	$39.15	$48.02	**$288.83**
39			**Change**	$0.21	$0.08	$0.07	$0.07	$0.06	$0.10	**$0.59**
40			**% Chg**	0.27%	0.19%	0.17%	0.17%	0.16%	0.20%	**0.2%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2025 vs. Actual Summer 2024

Residential Heating

	Summer 2024	Summer 2025
Customer Charge	$22.20	$22.20
First 50 Therms**	$1.0330	$1.0330
Over 50 therms**	$1.0330	$1.0330
LDAC	$0.0908	$0.0649
CGA	$0.3569	$0.3884

	Usage (Therms)	Summer 2024 Bill Amount	Summer 2025 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$29.60	$29.63	$0.03	0.1%	$0.00	0.0%	$0.16	0.5%	($0.13)	-0.4%
	10	$37.01	$37.06	$0.06	0.2%	$0.00	0.0%	$0.32	0.9%	($0.26)	-0.7%
	20	$51.81	$51.93	$0.11	0.2%	$0.00	0.0%	$0.63	1.2%	($0.52)	-1.0%
Monthly*	25	$59.22	$59.36	$0.14	0.2%	$0.00	0.0%	$0.79	1.3%	($0.65)	-1.1%
	30	$66.62	$66.79	$0.17	0.3%	$0.00	0.0%	$0.95	1.4%	($0.78)	-1.2%
	45	$88.83	$89.08	$0.25	0.3%	$0.00	0.0%	$1.42	1.6%	($1.17)	-1.3%
	50	$96.24	$96.52	$0.28	0.3%	$0.00	0.0%	$1.58	1.6%	($1.30)	-1.4%
	75	$133.25	$133.67	$0.42	0.3%	$0.00	0.0%	$2.36	1.8%	($1.94)	-1.5%
	125	$207.29	$207.99	$0.70	0.3%	$0.00	0.0%	$3.94	1.9%	($3.24)	-1.6%
	150	$244.31	$245.15	$0.84	0.3%	$0.00	0.0%	$4.73	1.9%	($3.89)	-1.6%
	200	$318.34	$319.46	$1.12	0.4%	$0.00	0.0%	$6.30	2.0%	($5.18)	-1.6%

* Monthly amount for benchmarking purposes, does not represent the average monthly use of Northern's residential class.
** Average distribution rates.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Non-Heating Bill

Comparison of Summer 2024 vs. Summer 2023

Line				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2		Typical Usage: therms(*)		12	8	8	8	8	9	53
3		**Summer 2024**								
4	Customer Charge	units @	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20
5	All	units @	$1.4005	$16.97	$11.69	$11.27	$11.27	$10.57	$12.26	$74.02
6	All	RDAC	$0.0933	$1.13	$0.78	$0.75	$0.75	$0.70	$0.82	$4.93
7		Total Base Rates	$1.4938	$18.10	$12.47	$12.02	$12.02	$11.27	$13.07	$78.96
8		COG 1	$0.3884	$4.71						$4.71
9		COG 2	$0.3884		$3.24					$3.24
10		COG 3	$0.3884			$3.12				$3.12
11		COG 4	$0.3884				$3.13			$3.13
12		COG 5	$0.3884					$2.93		$2.93
13		COG 6	$0.3884						$3.40	$3.40
14		Summer Period Avg. COG	$0.3884 *							
15		LDAC	$0.0649	$0.79	$0.54	$0.52	$0.52	$0.49	$0.57	$3.43
16			**TOTAL**	$45.79	$38.45	$37.86	$37.87	$36.89	$39.24	**$236.12**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
22	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
23	COG Change		**$ Change**	$0.38	$0.26	$0.25	$0.25	$0.24	$0.28	**$1.66**
24			**% Change**	0.83%	0.68%	0.67%	0.67%	0.65%	0.70%	**0.71%**
25	LDAC Change		**$ Change**	($0.31)	($0.22)	($0.21)	($0.21)	($0.20)	($0.23)	**($1.37)**
26			**% Change**	-0.69%	-0.56%	-0.55%	-0.55%	-0.53%	-0.58%	**-0.58%**
				May	June	July	August	Sept	October	Summer
27		Typical Usage: therms		12	8	8	8	8	9	53
28		**Summer 2023**								
29	Customer Charge	units @	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20
30	All	units @	$1.4005	$16.97	$11.69	$11.27	$11.27	$10.57	$12.26	$74.02
31	All	RDAC	$0.0933	$1.13	$0.78	$0.75	$0.75	$0.70	$0.82	$4.93
32		Total Base Rates	$1.4938	$18.10	$12.47	$12.02	$12.02	$11.27	$13.07	$78.96
33		COG 1	$0.3569	$4.32						$4.32
34		COG 2	$0.3569		$2.98					$2.98
35		COG 3	$0.3569			$2.87				$2.87
36		COG 4	$0.3569				$2.87			$2.87
37		COG 5	$0.3569					$2.69		$2.69
38		COG 6	$0.3569						$3.12	$3.12
39		Summer Period 2020 Avg. COG	$0.3569 *							
40		LDAC	$0.0908	$1.10	$0.76	$0.73	$0.73	$0.69	$0.79	$4.80
41			**TOTAL**	$45.73	$38.41	$37.82	$37.83	$36.85	$39.19	**$235.82**
42			**Change**	$0.07	$0.05	$0.05	$0.05	$0.04	$0.05	**$0.30**
43			**% Chg**	0.15%	0.12%	0.12%	0.12%	0.11%	0.13%	**0.13%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill

Comparison of Summer 2025 vs. Summer 2024

#			Rate	May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2		Typical Usage: therms(*)		102	33	23	23	22	42	245
3		**Summer 2025**								
4	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00
5	All	units @	$0.2554	$26.16	$8.36	$5.84	$5.89	$5.68	$10.66	$62.59
6	All	RDAC	$0.0008	$0.08	$0.03	$0.02	$0.02	$0.02	$0.03	$0.20
7		Total Base Rates	$0.2562	$26.24	$8.39	$5.86	$5.91	$5.69	$10.69	$62.78
8		COG 1	$0.4624	$47.36						$47.36
9		COG 2	$0.4624		$15.14					$15.14
10		COG 3	$0.4624			$10.58				$10.58
11		COG 4	$0.4624				$10.67			$10.67
12		COG 5	$0.4624					$10.28		$10.28
13		COG 6	$0.4624						$19.29	$19.29
14		Summer Period Avg. COG	$0.4624 *							
15		LDAC	$0.0374	$3.83	$1.22	$0.86	$0.86	$0.83	$1.56	$9.17
16			**TOTAL**	$157.43	$104.75	$97.29	$97.44	$96.80	$111.54	**$665.26**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
22	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
23	COG Change		**$ Change**	$5.63	$1.80	$1.26	$1.27	$1.22	$2.29	**$13.48**
24			**% Change**	3.16%	1.62%	1.23%	1.24%	1.21%	1.91%	**2.07%**
25	LDAC Change		**$ Change**	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	**($0.02)**
26			**% Change**	-0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
27				May	June	July	August	Sept	October	Summer
28		Typical Usage: therms		102	33	23	23	22	42	245
29		**Summer 2024**								
30	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00
31	All	units @	$0.2554	$26.16	$8.36	$5.84	$5.89	$5.68	$10.66	$62.59
32	All	RDAC	$0.0008	$0.08	$0.03	$0.02	$0.02	$0.02	$0.03	$0.20
33		Total Base Rates	$0.2562	$26.24	$8.39	$5.86	$5.91	$5.69	$10.69	$62.78
33		COG 1	$0.4074	$41.73						$41.73
34		COG 2	$0.4074		$13.34					$13.34
35		COG 3	$0.4074			$9.32				$9.32
36		COG 4	$0.4074				$9.40			$9.40
37		COG 5	$0.4074					$9.05		$9.05
38		COG 6	$0.4074						$17.00	$17.00
39		Summer Period 2020 Avg. COG	$0.4074 *							
40		LDAC	$0.0375	$3.84	$1.23	$0.86	$0.87	$0.83	$1.56	$9.19
41			**TOTAL**	$178.05	$111.35	$101.90	$102.09	$101.27	$119.94	**$651.81**
42			**Change**	($20.62)	($6.59)	($4.60)	($4.64)	($4.47)	($8.40)	**$13.45**
43			**% Chg**	-11.58%	-5.92%	-4.52%	-4.55%	-4.42%	-7.00%	**2.06%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill

Comparison of Summer 2025 vs. Summer 2024

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(*)			1,234	527	362	351	378	713	3,566
3	**Summer 2025**									
4	Customer Charge	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00
5	All	units @	$0.2881	$355.39	$151.76	$104.39	$101.25	$109.04	$205.43	$1,027.26
6	All	RDAC	$0.0008	$0.99	$0.42	$0.29	$0.28	$0.30	$0.57	$2.85
7		Total Base Rates	$0.2889	$356.38	$152.18	$104.68	$101.53	$109.34	$206.00	$1,030.12
8		COG 1	$0.4624	$570.40						$570.40
9		COG 2	$0.4624		$243.58					$243.58
10		COG 3	$0.4624			$167.55				$167.55
11		COG 4	$0.4624				$162.51			$162.51
12		COG 5	$0.4624					$175.00		$175.00
13		COG 6	$0.4624						$329.71	$329.71
14		Summer Period Avg. COG	$0.4624 *							
15		LDAC	$0.0374	$46.14	$19.70	$13.55	$13.14	$14.15	$26.67	$133.36
16			**TOTAL**	$1,197.91	$640.47	$510.78	$502.19	$523.49	$787.38	**$4,162.23**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
22	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
23	COG Change		**$ Change**	$67.85	$28.97	$19.93	$19.33	$20.82	$39.22	**$196.11**
24			**% Change**	6.00%	4.74%	4.06%	4.00%	4.14%	5.24%	**4.94%**
25	LDAC Change		**$ Change**	($0.12)	($0.05)	($0.04)	($0.04)	($0.04)	($0.07)	**($0.36)**
26			**% Change**	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	**-0.01%**
27				May	June	July	August	Sept	October	Summer
28	Typical Usage: therms			1,234	527	362	351	378	713	3,566
29	**Summer 2024**									
30	Customer Charge	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00
31	All	units @	$0.2881	$355.39	$151.76	$104.39	$101.25	$109.04	$205.43	$1,027.26
32	All	RDAC	$0.0008	$0.99	$0.42	$0.29	$0.28	$0.30	$0.57	$2.85
33		Total Base Rates	$0.2889	$356.38	$152.18	$104.68	$101.53	$109.34	$206.00	$1,030.12
34		COG 1	$0.4074	$502.55						$502.55
35		COG 2	$0.4074		$214.61					$214.61
36		COG 3	$0.4074			$147.62				$147.62
37		COG 4	$0.4074				$143.18			$143.18
38		COG 5	$0.4074					$154.19		$154.19
39		COG 6	$0.4074						$290.49	$290.49
40		Summer Period 2020 Avg. COG	$0.4074 *							
41		LDAC	$0.0375	$46.26	$19.75	$13.59	$13.18	$14.19	$26.74	$133.71
42			**TOTAL**	$1,130.19	$611.55	$490.89	$482.90	$502.72	$748.23	**$3,966.47**
43			**Change**	$67.72	$28.92	$19.89	$19.29	$20.78	$39.15	**$195.75**
44			**% Chg**	5.99%	4.73%	4.05%	4.00%	4.13%	5.23%	**4.94%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-42 Commercial & Industrial Bill

Comparison of Summer 2025 vs. Summer 2024

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(*)			8,263	4,842	4,185	4,857	5,825	8,566	36,538
3	Summer 2025									
4	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00
5	All	units @	$0.2182	$1,802.98	$1,056.44	$913.16	$1,059.83	$1,271.05	$1,869.18	$7,972.63
6	All	RDAC	$0.0008	$6.61	$3.87	$3.35	$3.89	$4.66	$6.85	$29.23
7		Total Base Rates	$0.2190	$1,809.59	$1,060.31	$916.51	$1,063.71	$1,275.71	$1,876.03	$8,001.86
8		COG 1	$0.4624	$3,820.80						$3,820.80
9		COG 2	$0.4624		$2,238.76					$2,238.76
10		COG 3	$0.4624			$1,935.13				$1,935.13
11		COG 4	$0.4624				$2,245.94			$2,245.94
12		COG 5	$0.4624					$2,693.56		$2,693.56
13		COG 6	$0.4624						$3,961.08	$3,961.08
14		Summer Period Avg. COG	$0.4624 *							
15		LDAC	$0.0374	$309.03	$181.08	$156.52	$181.66	$217.86	$320.38	$1,366.53
16			**TOTAL**	$7,289.42	$4,830.14	$4,358.15	$4,841.31	$5,537.13	$7,507.49	**$34,363.65**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
22	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
23	COG Change		**$ Change**	$454.46	$266.29	$230.17	$267.14	$320.38	$471.15	**$2,009.60**
24			**% Change**	6.65%	5.83%	5.58%	5.84%	6.14%	6.70%	**6.21%**
25	LDAC Change		**$ Change**	-$0.83	-$0.48	-$0.42	-$0.49	-$0.58	-$0.86	**($3.65)**
26			**% Change**	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	**-0.01%**
27				May	June	July	August	Sept	October	Summer
28	Typical Usage: therms			8,263	4,842	4,185	4,857	5,825	8,566	36,538
29	Summer 2024									
30	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00
31	All	units @	$0.2182	$1,802.98	$1,056.44	$913.16	$1,059.83	$1,271.05	$1,869.18	$7,972.63
32	All	RDAC	$0.0008	$6.61	$3.87	$3.35	$3.89	$4.66	$6.85	$29.23
33		Total Base Rates	$0.2190	$1,809.59	$1,060.31	$916.51	$1,063.71	$1,275.71	$1,876.03	$8,001.86
34		COG 1	$0.4074	$3,366.33						$3,366.33
35		COG 2	$0.4074		$1,972.47					$1,972.47
36		COG 3	$0.4074			$1,704.96				$1,704.96
37		COG 4	$0.4074				$1,978.80			$1,978.80
38		COG 5	$0.4074					$2,373.18		$2,373.18
39		COG 6	$0.4074						$3,489.93	$3,489.93
40		Summer Period 2020 Avg. COG	$0.4074 *							
41		LDAC	$0.0375	$309.86	$181.56	$156.94	$182.14	$218.44	$321.24	$1,370.18
42			**TOTAL**	$6,835.78	$4,564.34	$4,128.40	$4,574.65	$5,217.33	$7,037.20	**$32,357.70**
43			**Change**	$453.64	$265.80	$229.75	$266.66	$319.80	$470.29	**$2,005.95**
44			**% Chg**	6.64%	5.82%	5.57%	5.83%	6.13%	6.68%	**6.20%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-50 Commercial & Industrial Bill
Comparison of Summer 2025 vs. Summer 2024

Line				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2		Typical Usage: therms(*)		167	148	151	160	152	148	926
3	Summer 2025									
4	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00
5	All	units @	$0.2338	$39.15	$34.58	$35.22	$37.51	$35.47	$34.59	$216.52
6	All	RDAC	($0.0035)	($0.59)	($0.52)	($0.53)	($0.56)	($0.53)	($0.52)	($3.24)
7		Total Base Rates	$0.2303	$38.57	$34.06	$34.70	$36.94	$34.93	$34.08	$213.28
8		COG 1	$0.3197	$53.54						$53.54
9		COG 2	$0.3197		$47.28					$47.28
10		COG 3	$0.3197			$48.17				$48.17
11		COG 4	$0.3197				$51.29			$51.29
12		COG 5	$0.3197					$48.50		$48.50
13		COG 6	$0.3197						$47.31	$47.31
14		Summer Period Avg. COG	$0.3197 *							
15		LDAC	$0.0374	$6.26	$5.53	$5.63	$6.00	$5.67	$5.53	$34.64
16			**TOTAL**	$178.37	$166.87	$168.50	$174.23	$169.10	$166.92	**$1,023.99**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21		Total Base Rate Change	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
22		Total Base Rate Change	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
23	COG Change		**$ Change**	$5.06	$4.47	$4.55	$4.84	$4.58	$4.47	**$27.97**
24			**% Change**	2.92%	2.75%	2.77%	2.86%	2.78%	2.75%	**2.81%**
25	LDAC Change		**$ Change**	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	-$0.01	**($0.09)**
26			**% Change**	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	**-0.01%**
27				May	June	July	August	Sept	October	Summer
28		Typical Usage: therms		167	148	151	160	152	148	926
29	Summer 2024									
30	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00
31	All	units @	$0.2338	$39.15	$34.58	$35.22	$37.51	$35.47	$34.59	$216.52
32	All	RDAC	($0.0035)	($0.59)	($0.52)	($0.53)	($0.56)	($0.53)	($0.52)	($3.24)
33		Total Base Rates	$0.2303	$38.57	$34.06	$34.70	$36.94	$34.93	$34.08	$213.28
33		COG 1	$0.2895	$48.48						$48.48
34		COG 2	$0.2895		$42.81					$42.81
35		COG 3	$0.2895			$43.62				$43.62
36		COG 4	$0.2895				$46.44			$46.44
37		COG 5	$0.2895					$43.91		$43.91
38		COG 6	$0.2895						$42.84	$42.84
39		Summer Period 2020 Avg. COG	$0.2895 *							
40		LDAC	$0.0375	$6.28	$5.55	$5.65	$6.02	$5.69	$5.55	$34.73
41			**TOTAL**	$173.33	$162.42	$163.96	$169.40	$164.54	$162.46	**$996.11**
42			**Change**	$5.04	$4.45	$4.53	$4.83	$4.57	$4.45	**$27.88**
43			**% Chg**	2.91%	2.74%	2.77%	2.85%	2.78%	2.74%	**2.80%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 7,530 therms/Summer

Comparison of Summer 2025 vs. Summer 2024

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2		Typical Usage: therms(*)		1,438	1,198	1,173	1,164	1,117	1,300	7,391
3		Summer 2025								
4	Customer Charg	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00
5	All	units @	$0.1763	$253.57	$211.18	$206.85	$205.24	$196.99	$229.21	$1,303.06
6	All	RDAC	($0.0035)	($5.03)	($4.19)	($4.11)	($4.07)	($3.91)	($4.55)	($25.87)
7		Total Base Rates	$0.1728	$248.54	$206.99	$202.75	$201.17	$193.08	$224.66	$1,277.19
8		COG 1	$0.3197	$459.82						$459.82
9		COG 2	$0.3197		$382.96					$382.96
10		COG 3	$0.3197			$375.10				$375.10
11		COG 4	$0.3197				$372.19			$372.19
12		COG 5	$0.3197					$357.23		$357.23
13		COG 6	$0.3197						$415.65	$415.65
14		Summer Period Avg. COG	$0.3197 *							
15		LDAC	$0.0374	$53.79	$44.80	$43.88	$43.54	$41.79	$48.63	$276.43
16			**TOTAL**	$987.15	$859.75	$846.73	$841.89	$817.10	$913.94	**$5,266.56**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$209.32	$200.90	$233.76	**$643.99**
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	25.94%	25.64%	26.72%	12.77%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Total Base Rate Change		**$ Change**	($5.03)	($4.19)	($4.11)	$205.24	$196.99	$229.21	**$618.12**
22	Total Base Rate Change		**% Change**	-0.53%	-0.51%	-0.51%	25.44%	25.14%	26.20%	**12.25%**
23	COG Change		**$ Change**	$43.44	$36.18	$35.43	$35.16	$33.74	$39.26	**$223.21**
24			**% Change**	4.60%	4.39%	4.37%	4.36%	4.31%	4.49%	**4.43%**
25	LDAC Change		**$ Change**	($0.14)	($0.12)	($0.12)	($0.12)	($0.11)	($0.13)	**($0.74)**
26			**% Change**	-0.02%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	**-0.01%**
27				May	June	July	August	Sept	October	Summer
28		Typical Usage: therms		1,438	1,198	1,173	1,164	1,117	1,300	7,391
29		Summer 2024								
30	Customer Charg	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00
31	All	units @	$0.1763	$253.57	$211.18	$206.85	$205.24	$196.99	$229.21	$1,303.06
32	All	RDAC	($0.0035)	($5.03)	($4.19)	($4.11)	($4.07)	($3.91)	($4.55)	($25.87)
33		Total Base Rates	$0.1728	$248.54	$206.99	$202.75	$201.17	$193.08	$224.66	$1,277.19
34		COG 1	$0.2895	$416.38						$416.38
35		COG 2	$0.2895		$346.78					$346.78
36		COG 3	$0.2895			$339.67				$339.67
37		COG 4	$0.2895				$337.03			$337.03
38		COG 5	$0.2895					$323.48		$323.48
39		COG 6	$0.2895						$376.39	$376.39
40		Summer Period 2020 Avg. COG	$0.2895 *							
41		LDAC	$0.0375	$53.94	$44.92	$44.00	$43.66	$41.90	$48.76	$277.17
42			**TOTAL**	$943.86	$823.69	$811.42	$806.85	$783.47	$874.81	**$5,044.09**
43			**Change**	$43.29	$36.06	$35.32	$35.04	$33.63	$39.13	**$222.47**
44			**% Chg**	4.59%	4.38%	4.35%	4.34%	4.29%	4.47%	**4.41%**

*-Note- Weighted by actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-52 Commercial & Industrial Bill
Comparison of Summer 2025 vs. Summer 2024

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2		Typical Usage: therms(*)		38,452	32,161	33,533	41,062	38,634	40,261	224,104
3	**Summer 2025**									
4	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00
5	All	units @	$0.1094	$4,206.64	$3,518.45	$3,668.53	$4,492.18	$4,226.59	$4,404.54	$24,516.94
6	All	RDAC	($0.0035)	($134.58)	($112.56)	($117.37)	($143.72)	($135.22)	($140.91)	($784.36)
7		Total Base Rates	$0.1059	$4,072.06	$3,405.89	$3,551.17	$4,348.46	$4,091.37	$4,263.62	$23,732.57
8		COG 1	$0.3197	$12,293.08						$12,293.08
9		COG 2	$0.3197		$10,281.99					$10,281.99
10		COG 3	$0.3197			$10,720.57				$10,720.57
11		COG 4	$0.3197				$13,127.51			$13,127.51
12		COG 5	$0.3197					$12,351.38		$12,351.38
13		COG 6	$0.3197						$12,871.39	$12,871.39
14		Summer Period Avg. COG	$0.3197 *							
15		LDAC	$0.0374	$1,438.10	$1,202.84	$1,254.14	$1,535.72	$1,444.92	$1,505.76	$8,381.48
16		**TOTAL**		$19,153.24	$16,240.72	$16,875.88	$20,361.69	$19,237.68	$19,990.77	**$111,859.98**
17	Base Rate Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
18	Base Rate Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	RDAC Change Summer		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20	RDAC Change Summer		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21		Total Base Rate Change	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
22		Total Base Rate Change	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
23	COG Change		**$ Change**	$1,161.25	$971.27	$1,012.70	$1,240.07	$1,166.76	$1,215.88	**$6,767.93**
24			**% Change**	6.45%	6.36%	6.38%	6.48%	6.46%	6.47%	**6.44%**
25	LDAC Change		**$ Change**	($3.85)	($3.22)	($3.35)	($4.11)	($3.86)	($4.03)	**($22.41)**
26			**% Change**	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%	**-0.02%**
27				May	June	July	August	Sept	October	Summer
28		Typical Usage: therms		38,452	32,161	33,533	41,062	38,634	40,261	224,104
29	**Summer 2024**									
30	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00
31	All	units @	$0.1094	$4,206.64	$3,518.45	$3,668.53	$4,492.18	$4,226.59	$4,404.54	$24,516.94
32	All	RDAC	($0.0035)	($134.58)	($112.56)	($117.37)	($143.72)	($135.22)	($140.91)	($784.36)
33		Total Base Rates	$0.1059	$4,072.06	$3,405.89	$3,551.17	$4,348.46	$4,091.37	$4,263.62	$23,732.57
34		COG 1	$0.2895	$11,131.83						$11,131.83
35		COG 2	$0.2895		$9,310.72					$9,310.72
36		COG 3	$0.2895			$9,707.87				$9,707.87
37		COG 4	$0.2895				$11,887.44			$11,887.44
38		COG 5	$0.2895					$11,184.63		$11,184.63
39		COG 6	$0.2895						$11,655.51	$11,655.51
40		Summer Period 2020 Avg. COG	$0.2895 *							
41		LDAC	$0.0375	$1,441.95	$1,206.05	$1,257.50	$1,539.82	$1,448.79	$1,509.78	$8,403.89
42		**TOTAL**		$17,995.84	$15,272.66	$15,866.53	$19,125.73	$18,074.79	$18,778.92	**$105,114.46**
43		**Change**		$1,157.40	$968.06	$1,009.35	$1,235.97	$1,162.89	$1,211.85	**$6,745.52**
44		**% Chg**		6.43%	6.34%	6.36%	6.46%	6.43%	6.45%	**6.42%**

*-Note- Weighted by actual usage.

DOE 1-15 Attachment - Winter

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		44	81	96	116	88	68	494	38	15	12	12	11	17	105	599
3		Winter 2024 - 2025																
4	Customer Charge	units @	$ 22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20								
5	All	units @	$0.9259	$40.70	$75.35	$89.09	$107.43	$81.69	$63.28	$457.54								
6	All	RDAC	$0.0434	$1.91	$3.53	$4.18	$5.04	$3.83	$2.97	$21.45								
7		Total Base Rates	$0.9693	$42.60	$78.88	$93.27	$112.46	$85.52	$66.25	$478.98								
6		COG 1	$0.6553	$28.80						$28.80								
7		COG 2	$0.6553		$53.33					$53.33								
8		COG 3	$0.6553			$63.05				$63.05								
9		COG 4	$0.6553				$76.03			$76.03								
10		COG 5	$0.6553					$57.82		$57.82								
11		COG 6	$0.6553						$44.79	$44.79								
12		LDAC	$0.0649	$2.85	$5.28	$6.24	$7.53	$5.73	$4.44	$32.07								
13		Summer 2025																
14	Customer Charge	units @	$ 22.20								$ 22.20	$22.20	$22.20	$22.20	$ 22.20	$22.20	$133.20	
15	All	units @	$0.9259								$34.86	$13.75	$11.05	$10.91	$10.60	$16.15	$97.32	
16	All	RDAC	$0.1071								$4.03	$1.59	$1.28	$1.26	$1.23	$1.87	$11.26	
17		Total Base Rates	$1.0330								$38.90	$15.34	$12.33	$12.17	$11.82	$18.01	$108.58	
16		COG 1	$0.3884								$14.63						$14.63	
17		COG 2	$0.3884									$5.77					$5.77	
18		COG 3	$0.3884										$4.64				$4.64	
19		COG 4	$0.3884											$4.58			$4.58	
20		COG 5	$0.3884												$4.45		$4.45	
21		COG 6	$0.3884													$6.77	$6.77	
22		Summer Period Weighted Avg. COG	$0.3884															
23		LDAC	$ 0.0649								$2.44	$0.96	$0.77	$0.76	$0.74	$1.13	$6.82	
24			TOTAL	$96.46	$159.69	$184.76	$218.22	$171.27	$137.67	$968.07	$ 78.17	$ 44.27	$ 39.94	$ 39.71	$ 39.21	$ 48.12	$ 289.42	$1,257.50
	Base Rate Change Winter		$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
	Base Rate Change Winter		% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	RDAC Change Winter		$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
	RDAC Change Winter		% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
		Total Base Rate Change	$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
		Total Base Rate Change	% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	COG Change Winter		$ Change	($3.20)	($4.41)	($2.85)	($3.43)	$12.98	-$16.24	($17.16)								
			% Change	-3.18%	-2.66%	-1.50%	-1.53%	8.08%	-10.43%	-1.72%								
	LDAC Change Winter		$ Change	($1.03)	($1.90)	($2.49)	($3.01)	($2.29)	($1.77)	($12.49)								
			% Change	-1.02%	-1.15%	-1.31%	-1.34%	-1.42%	-1.14%	-1.25%								
25				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26		Typical Usage: therms		44	81	96	116	88	68	494	38	15	12	12	11	17	105	599
27		Winter 2023 - 2024																
28	Customer Charge	units @	$ 22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20								
29	All	units @	$0.9259	$40.70	$75.35	$89.09	$107.43	$81.69	$63.28	$457.54								
30	All	RDAC	$0.0434	$1.91	$3.53	$4.18	$5.04	$3.83	$2.97	$21.45								
31		Total Base Rates	$0.9693	$42.60	$78.88	$93.27	$112.46	$85.52	$66.25	$478.98								
32		COG 1	$0.7282	$32.01						$32.01								
33		COG 2	$0.7095		$57.74					$57.74								
34		COG 3	$0.6849			$65.90				$65.90								
35		COG 4	$0.6849				$79.47			$79.47								
36		COG 5	$0.5082					$44.84		$44.84								
37		COG 6	$0.8929						$61.03	$61.03								
38		Winter Period Weighted Avg. COG	$0.6900															
39		LDAC	$ 0.0883	$3.88	$7.19					$11.07								
40		LDAC 2, January 1	$ 0.0908			$8.74	$10.54	$8.01	$6.21	$33.49								
41																		
42		Summer 2024																
43	Customer Charge	units @	$ 22.20								$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20	
44	All	units @	$0.9259								$34.86	$13.75	$11.05	$10.91	$10.60	$16.15	$97.32	
45	All	RDAC	$0.1071								$4.03	$1.59	$1.28	$1.26	$1.23	$1.87	$11.26	
46		Total Base Rates	$1.0330								$38.90	$15.34	$12.33	$12.17	$11.82	$18.01	$108.58	
47		COG 1	$0.3569								$13.44						$13.44	
48		COG 2	$0.3569									$5.30					$5.30	
49		COG 3	$0.3569										$4.26				$4.26	
50		COG 4	$0.3569											$4.20			$4.20	
51		COG 5	$0.3569												$4.08		$4.08	
52		COG 6	$0.3569													$6.22	$6.22	
53		Summer Period Weighted Avg. COG	$0.3569															
54		LDAC	$ 0.0908								$3.42	$1.35	$1.08	$1.07	$1.04	$1.58	$9.54	
55			TOTAL	$100.69	$166.01	$190.10	$224.66	$160.57	$155.68	$997.72	$77.96	$44.19	$39.88	$39.64	$39.15	$48.02	$288.83	$1,286.55
56			Change	($4.23)	($6.32)	($5.34)	($6.44)	$10.69	($18.01)	($29.64)	$0.21	$0.08	$0.07	$0.07	$0.06	$0.10	$0.59	($29.05)
57			% Chg	-4.20%	-3.80%	-2.81%	-2.87%	6.66%	-11.57%	-3.0%	0.27%	0.19%	0.17%	0.17%	0.16%	0.20%	0.20%	-2.26%

*-Note- Weighted by most recent 12-month actual usage.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 2023-2024 vs. Actual Winter 2022-2023

Residential Heating	Winter 2023- 2024	Winter 2024- 2025
Customer Charge	$22.20	$22.20
All Therms	$0.9693	$0.9693
LDAC**	$0.0900	$0.0649
CGA	$0.6900	$0.6553

	Usage (Therms)	Winter 2022-2023 Bill Amount	Winter 2023-2024 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$30.95	$30.65	($0.30)	-1.0%	$0.00	0.0%	($0.17)	-0.5%	($0.13)	-0.4%
	10	$39.69	$39.10	($0.60)	-1.5%	$0.00	0.0%	($0.35)	-0.9%	($0.25)	-0.6%
	20	$57.19	$55.99	($1.20)	-2.1%	$0.00	0.0%	($0.69)	-1.2%	($0.50)	-0.9%
	25	$65.93	$64.44	($1.49)	-2.3%	$0.00	0.0%	($0.87)	-1.3%	($0.63)	-1.0%
	30	$74.68	$72.89	($1.79)	-2.4%	$0.00	0.0%	($1.04)	-1.4%	($0.75)	-1.0%
	45	$100.92	$98.23	($2.69)	-2.7%	$0.00	0.0%	($1.56)	-1.5%	($1.13)	-1.1%
	50	$109.66	$106.68	($2.99)	-2.7%	$0.00	0.0%	($1.74)	-1.6%	($1.25)	-1.1%
	75	$153.40	$148.91	($4.48)	-2.9%	$0.00	0.0%	($2.60)	-1.7%	($1.88)	-1.2%
Monthly*	125	$240.86	$233.39	($7.47)	-3.1%	$0.00	0.0%	($4.34)	-1.8%	($3.13)	-1.3%
	150	$284.59	$275.63	($8.97)	-3.2%	$0.00	0.0%	($5.21)	-1.8%	($3.76)	-1.3%
	200	$372.06	$360.10	($11.96)	-3.2%	$0.00	0.0%	($6.94)	-1.9%	($5.01)	-1.3%

* Monthly amount for benchmarking purposes, does not represent the average monthly use of Northern's residential class.

DOE 1-15 Attachment - Winter

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Non-Heating Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1																		
2		Typical Usage: therms (*)		12	18	21	24	20	16	111	12	8	8	8	8	9	53	164
3		**Winter 2023 - 2024**																
4	Customer Charge	units @	$ 22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20								
5	All	units @	$1.4005	$16.37	$25.25	$29.25	$34.08	$27.72	$22.91	$155.58								
6	All	RDAC	$0.0588	$0.69	$1.06	$1.23	$1.43	$1.16	$0.96	$6.53								
7		Total Base Rates	$1.4593	$17.06	$26.31	$30.48	$35.51	$28.89	$23.87	$162.12								
6		COG 1	$0.6553	$7.66						$7.66								
7		COG 2	$0.6553		$11.81					$11.81								
8		COG 3	$0.6553			$13.69				$13.69								
9		COG 4	$0.6553				$15.94			$15.94								
10		COG 5	$0.6553					$12.97		$12.97								
11		COG 6	$0.6553						$10.72	$10.72								
12		LDAC	$0.0649	$0.76	$1.17	$1.36	$1.58	$1.28	$1.06	$7.21								
13		**Summer 2024**																
14	Customer Charge	units @	$ 22.20								$ 22.20	$22.20	$22.20	$22.20	$ 22.20	$22.20	$133.20	
15	All	units @	$1.4005								$16.97	$11.69	$11.27	$11.27	$10.57	$12.26	$74.02	
16	All	RDAC	$0.0933								$1.13	$0.78	$0.75	$0.75	$0.70	$0.82	$4.93	
17		Total Base Rates	$1.4938								$18.10	$12.47	$12.02	$12.02	$11.27	$13.07	$78.96	
16		COG 1	$0.3884								$4.71						$4.71	
17		COG 2	$0.3884									$3.24					$3.24	
18		COG 3	$0.3884										$3.12				$3.12	
19		COG 4	$0.3884											$3.13			$3.13	
20		COG 5	$0.3884												$2.93		$2.93	
21		COG 6	$0.3884													$3.40	$3.40	
22	Summer Period Weighted Avg. COG		$0.3884															
23		LDAC	$ 0.0649								$0.79	$0.54	$0.52	$0.52	$0.49	$0.57	$3.43	
24			**TOTAL**	$47.68	$61.49	$67.72	$75.23	$65.34	$57.86	**$375.32**	$45.79	$38.45	$37.86	$37.87	$36.89	$39.24	$236.12	$611.44

		Nov	Dec	Jan	Feb	Mar	Apr	Winter
Base Rate Change Winter	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Base Rate Change Winter	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RDAC Change Winter	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
RDAC Change Winter	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Base Rate Change	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Total Base Rate Change	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
COG Change Winter	**$ Change**	($0.85)	($0.98)	($0.62)	($0.72)	$2.91	-$3.89	**($4.14)**
	% Change	-1.75%	-1.55%	-0.90%	-0.94%	4.63%	-6.25%	**-1.08%**
LDAC Change Winter	**$ Change**	($0.27)	($0.42)	($0.54)	($0.63)	($0.51)	($0.42)	**($2.80)**
	% Change	-0.56%	-0.67%	-0.79%	-0.82%	-0.81%	-0.68%	**-0.73%**

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26																		
27		Typical Usage: therms		12	18	21	24	20	16	111	12	8	8	8	8	9	53	164
28		**Winter 2023 - 2024**																
29	Customer Charge	units @	$ 22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20								
30	All	units @	$1.4005	$16.37	$25.25	$29.25	$34.08	$27.72	$22.91	$155.58								
31	All	RDAC	$0.0588	$0.69	$1.06	$1.23	$1.43	$1.16	$0.96	$6.53								
32		Total Base Rates	$1.4593	$17.06	$26.31	$30.48	$35.51	$28.89	$23.87	$162.12								
33		COG 1	$0.7282	$8.51						$8.51								
34		COG 2	$0.7095		$12.79					$12.79								
35		COG 3	$0.6849			$14.31				$14.31								
36		COG 4	$0.6849				$16.66			$16.66								
37		COG 5	$0.5082					$10.06		$10.06								
38		COG 6	$0.8929						$14.61	$14.61								
39	Winter Period Weighted Avg. COG		$0.6926															
40		LDAC	$ 0.0883	$1.03	$1.59					$2.62								
41		LDAC 2, January 1	$ 0.0908			$1.90	$2.21	$1.80	$1.49	$7.39								
42																		
43		**Summer 2024**																
44	Customer Charge	units @	$ 22.20								$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20	
45	All	units @	$1.4005								$16.97	$11.69	$11.27	$11.27	$10.57	$12.26	$74.02	
46	All	RDAC	$0.0933								$1.13	$0.78	$0.75	$0.75	$0.70	$0.82	$4.93	
47		Total Base Rates	$1.4938								$18.10	$12.47	$12.02	$12.02	$11.27	$13.07	$78.96	
48		COG 1	$0.3569								$4.32						$4.32	
49		COG 2	$0.3569									$2.98					$2.98	
50		COG 3	$0.3569										$2.87				$2.87	
51		COG 4	$0.3569											$2.87			$2.87	
52		COG 5	$0.3569												$2.69		$2.69	
53		COG 6	$0.3569													$3.12	$3.12	
54	Summer Period Weighted Avg. COG		$0.3569															
55		LDAC	$ 0.0908								$1.10	$0.76	$0.73	$0.73	$0.69	$0.79	$4.80	
56			**TOTAL**	$48.80	$62.89	$68.88	$76.58	$62.94	$62.17	**$382.27**	$45.73	$38.41	$37.82	$37.83	$36.85	$39.19	$235.82	$618.09
57			**Change**	($1.13)	($1.40)	($1.16)	($1.35)	$2.40	($4.31)	**($6.95)**	$0.07	$0.05	$0.05	$0.05	$0.04	$0.05	**$0.30**	($6.65)
58			**% Chg**	-2.31%	-2.22%	-1.68%	-1.76%	3.81%	-6.93%	**-1.8%**	0.15%	0.12%	0.12%	0.12%	0.11%	0.13%	**0.13%**	-1.08%

*-Note- Weighted by most recent 12-month actual usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		134	255	315	377	281	214	1,576	102	33	23	23	22	42	245	1,821
3	**Winter 2024 - 2025**																	
4	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00								
5	All	units @	$0.2554	$34.18	$65.23	$80.51	$96.36	$71.80	$54.55	$402.62								
6	All	RDAC	$0.0169	$2.26	$4.32	$5.33	$6.38	$4.75	$3.61	$26.64								
7		Total Base Rates	$0.2723	$36.44	$69.54	$85.84	$102.73	$76.55	$58.16	$429.26								
6		COG 1	$0.6636	$88.80						$88.80								
7		COG 2	$0.6636		$169.48					$169.48								
8		COG 3	$0.6636			$209.18				$209.18								
9		COG 4	$0.6636				$250.36			$250.36								
10		COG 5	$0.6636					$186.55		$186.55								
11		COG 6	$0.6636						$141.75	$141.75								
12		LDAC	$0.0374	$5.00	$9.55	$11.79	$14.11	$10.51	$7.99	$58.96								
13	**Summer 2025**																	
14	Customer Charge	units @	$ 80.00								$ 80.00	$80.00	$80.00	$80.00	$ 80.00	$80.00	$480.00	
15	All	units @	$0.2554								$26.16	$8.36	$5.84	$5.89	$5.68	$10.66	$62.59	
16	All	RDAC	$0.0008								$0.08	$0.03	$0.02	$0.02	$0.02	$0.03	$0.20	
17		Total Base Rates	$0.2562								$26.24	$8.39	$5.86	$5.91	$5.69	$10.69	$62.78	
16		COG 1	$0.4624								$47.36						$47.36	
17		COG 2	$0.4624									$15.14					$15.14	
18		COG 3	$0.4624										$10.58				$10.58	
19		COG 4	$0.4624											$10.67			$10.67	
20		COG 5	$0.4624												$10.28		$10.28	
21		COG 6	$0.4624													$19.29	$19.29	
22	Summer Period Weighted Avg. COG		$0.4624															
23		LDAC	$ 0.0374								$3.83	$1.22	$0.86	$0.86	$0.83	$1.56	$9.17	
24			**TOTAL**	$210.24	$328.57	$386.81	$447.20	$353.61	$287.90	**$2,014.34**	$ 157.43	$ 104.75	$ 97.29	$ 97.44	$ 96.80	$ 111.54	$ 665.26	$2,679.60

		Nov	Dec	Jan	Feb	Mar	Apr	Winter
Base Rate Change Winter	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Base Rate Change Winter	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RDAC Change Winter	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
RDAC Change Winter	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Base Rate Change	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Total Base Rate Change	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
COG Change Winter	**$ Change**	($10.25)	($14.79)	($10.50)	($12.56)	$40.31	-$51.54	**($59.33)**
	% Change	-4.7%	-4.3%	-2.6%	-2.7%	12.9%	-15.2%	**-2.9%**
LDAC Change Winter	**$ Change**	$0.16	$0.31	($0.03)	($0.04)	($0.03)	($0.02)	**$0.35**
	% Change	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	**0.0%**

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
25				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26		Typical Usage: therms		134	255	315	377	281	214	1,576	102	33	23	23	22	42	245	1,821
27	**Winter 2023 - 2024**																	
28	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00								
29	All	units @	$0.2554	$34.18	$65.23	$80.51	$96.36	$71.80	$54.55	$402.62								
30	All	RDAC	$0.0169	$2.26	$4.32	$5.33	$6.38	$4.75	$3.61	$26.64								
31		Total Base Rates	$0.2723	$36.44	$69.54	$85.84	$102.73	$76.55	$58.16	$429.26								
32		COG 1	$0.7402	$99.05						$99.05								
33		COG 2	$0.7215		$184.26					$184.26								
34		COG 3	$0.6969			$219.68				$219.68								
35		COG 4	$0.6969				$262.93			$262.93								
36		COG 5	$0.5202					$146.23		$146.23								
37		COG 6	$0.9049						$193.29	$193.29								
38	Winter Period Weighted Avg. COG		$0.7012															
39		LDAC	$ 0.0362	$4.84	$9.25					$14.09								
40		LDAC 2, January 1	$ 0.0375			$11.82	$14.15	$10.54	$8.01	$44.52								
41																		
42	**Summer 2024**																	
43	Customer Charge**	units @	$ 80.00								$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00	
44	All	units @	$0.2554								$26.16	$8.36	$5.84	$5.89	$5.68	$10.66	$62.59	
45	All	RDAC	$0.0008								$0.08	$0.03	$0.02	$0.02	$0.02	$0.03	$0.20	
46		Total Base Rates	$0.2562								$26.24	$8.39	$5.86	$5.91	$5.69	$10.69	$62.78	
47		COG 1	$0.4074								$41.73						$41.73	
48		COG 2	$0.4074									$13.34					$13.34	
49		COG 3	$0.4074										$9.32				$9.32	
50		COG 4	$0.4074											$9.40			$9.40	
51		COG 5	$0.4074												$9.05		$9.05	
52		COG 6	$0.4074													$17.00	$17.00	
53	Summer Period Weighted Avg. COG		$0.4074															
54		LDAC	$ 0.0375								$3.84	$1.23	$0.86	$0.87	$0.83	$1.56	$9.19	
55			**TOTAL**	$220.33	$343.05	$397.34	$459.81	$313.32	$339.47	**$2,073.32**	$151.81	$102.96	$96.04	$96.18	$95.58	$109.25	$651.81	$2,725.13
56			**Change**	($10.09)	($14.48)	($10.53)	($12.60)	$40.28	($51.56)	**($58.98)**	$5.62	$1.80	$1.26	$1.27	$1.22	$2.29	**$13.45**	($45.53)
57			**% Chg**	-4.58%	-4.22%	-2.65%	-2.74%	12.86%	-15.19%	**-2.84%**	3.70%	1.75%	1.31%	1.32%	1.28%	2.10%	**2.06%**	-1.67%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		1,651	2,681	3,148	3,627	2,919	2,198	16,223	1,234	527	362	351	378	713	3,566	19,788
3		**Winter 2024 - 2025**																
4	Customer Charge	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00								
5	All	units @	$0.2881	$475.65	$772.42	$906.84	$1,044.84	$840.85	$633.19	$4,673.78								
6	All	RDAC	$0.0169	$27.90	$45.31	$53.20	$61.29	$49.32	$37.14	$274.16								
7		Total Base Rates	$0.3050	$503.55	$817.73	$960.04	$1,106.13	$890.17	$670.33	$4,947.94								
6		COG 1	$0.6636	$1,095.59						$1,095.59								
7		COG 2	$0.6636		$1,779.16					$1,779.16								
8		COG 3	$0.6636			$2,088.78				$2,088.78								
9		COG 4	$0.6636				$2,406.64			$2,406.64								
10		COG 5	$0.6636					$1,936.78		$1,936.78								
11		COG 6	$0.6636						$1,458.47	$1,458.47								
12		LDAC	$0.0374	$61.75	$100.27	$117.72	$135.64	$109.16	$82.20	$606.73								
13		**Summer 2025**																
14	Customer Charge	units @	$ 225.00								$ 225.00	$225.00	$225.00	$225.00	$ 225.00	$225.00	$1,350.00	
15	All	units @	$0.2881								$355.39	$151.76	$104.39	$101.25	$109.04	$205.43	$1,027.26	
16	All	RDAC	$0.0008								$0.99	$0.42	$0.29	$0.28	$0.30	$0.57	$2.85	
17		Total Base Rates	$0.2889								$356.38	$152.18	$104.68	$101.53	$109.34	$206.00	$1,030.12	
16		COG 1	$0.4624								$570.40						$570.40	
17		COG 2	$0.4624									$243.58					$243.58	
18		COG 3	$0.4624										$167.55				$167.55	
19		COG 4	$0.4624											$162.51			$162.51	
20		COG 5	$0.4624												$175.00		$175.00	
21		COG 6	$0.4624													$329.71	$329.71	
22	Summer Period Weighted Avg. COG		$0.4624															
23		LDAC	$ 0.0374								$46.14	$19.70	$13.55	$13.14	$14.15	$26.67	$133.36	
24			TOTAL	$1,885.88	$2,922.15	$3,391.54	$3,873.40	$3,161.11	$2,436.00	**$17,670.09**	$1,197.91	$ 640.47	$ 510.78	$ 502.19	$ 523.49	$ 787.38	$4,162.23	$21,832.32

		Nov	Dec	Jan	Feb	Mar	Apr	Winter
Base Rate Change Winter	$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Base Rate Change Winter	% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RDAC Change Winter	$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
RDAC Change Winter	% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Base Rate Change	$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Total Base Rate Change	% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
COG Change Winter	$ Change	($126.46)	($155.23)	($104.82)	($120.77)	$418.53	-$530.33	**($619.09)**
	% Change	-5.03%	-3.99%	-2.35%	-2.37%	11.52%	-14.58%	**-3.39%**
LDAC Change Winter	$ Change	$1.98	$3.22	($0.31)	($0.36)	($0.29)	($0.22)	**$4.01**
	% Change	0.079%	0.083%	-0.007%	-0.007%	-0.008%	-0.006%	**0.02%**

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
25				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26		Typical Usage: therms		1,651	2,681	3,148	3,627	2,919	2,198	16,223	1,234	527	362	351	378	713	3,566	19,788
27		**Winter 2023 - 2024**																
28	Customer Charge	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00								
29	All	units @	$0.2881	$475.65	$772.42	$906.84	$1,044.84	$840.85	$633.19	$4,673.78								
30	All	RDAC	$0.0169	$27.90	$45.31	$53.20	$61.29	$49.32	$37.14	$274.16								
31		Total Base Rates	$0.3050	$503.55	$817.73	$960.04	$1,106.13	$890.17	$670.33	$4,947.94								
32		COG 1	$0.7402	$1,222.05						$1,222.05								
33		COG 2	$0.7215		$1,934.39					$1,934.39								
34		COG 3	$0.6969			$2,193.60				$2,193.60								
35		COG 4	$0.6969				$2,527.41			$2,527.41								
36		COG 5	$0.5202					$1,518.26		$1,518.26								
37		COG 6	$0.9049						$1,988.80	$1,988.80								
38	Winter Period Weighted Avg. COG		$0.7018															
39		LDAC	$ 0.0362	$59.77	$97.05					$156.82								
40		LDAC 2, January 1	$ 0.0375			$118.04	$136.00	$109.45	$82.42	$445.90								
41																		
42		**Summer 2024**																
43	Customer Charge**	units @	$ 225.00								$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00	
44	All	units @	$0.2881								$355.39	$151.76	$104.39	$101.25	$109.04	$205.43	$1,027.26	
45	All	RDAC	$0.0008								$0.99	$0.42	$0.29	$0.28	$0.30	$0.57	$2.85	
46		Total Base Rates	$0.2889								$356.38	$152.18	$104.68	$101.53	$109.34	$206.00	$1,030.12	
47		COG 1	$0.4074								$502.55						$502.55	
48		COG 2	$0.4074									$214.61					$214.61	
49		COG 3	$0.4074										$147.62				$147.62	
50		COG 4	$0.4074											$143.18			$143.18	
51		COG 5	$0.4074												$154.19		$154.19	
52		COG 6	$0.4074													$290.49	$290.49	
53	Summer Period Weighted Avg. COG		$0.4074															
54		LDAC	$ 0.0375								$46.26	$19.75	$13.59	$13.18	$14.19	$26.74	$133.71	
55			TOTAL	$2,513.92	$3,891.89	$4,456.71	$5,100.66	$3,633.05	$3,636.89	**$18,285.17**	$1,130.19	$611.55	$490.89	$482.90	$502.72	$748.23	$3,966.47	$22,251.64
56			Change	($628.03)	($969.74)	($1,065.17)	($1,227.26)	($471.94)	($1,200.89)	**($615.08)**	$67.72	$28.92	$19.89	$19.29	$20.78	$39.15	**$195.75**	($419.32)
57			% Chg	-24.98%	-24.92%	-23.90%	-24.06%	-12.99%	-33.02%	**-3.36%**	5.99%	4.73%	4.05%	4.00%	4.13%	5.23%	**4.94%**	-1.88%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-42 Commercial & Industrial Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
2		Typical Usage: therms (*)		17,512	20,258	25,086	23,013	18,768	14,436	119,072	8,263	4,842	4,185	4,857	5,825	8,566	36,538	155,610
3	**Winter 2024 - 2025**																	
4	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00								
5	All	units @	$0.2182	$3,821.06	$4,420.36	$5,473.67	$5,021.35	$4,095.15	$3,149.83	$25,981.42								
6	All	RDAC	$0.0169	$295.95	$342.37	$423.95	$388.91	$317.18	$243.96	$2,012.31								
7		Total Base Rates	$0.2351	$4,117.01	$4,762.73	$5,897.62	$5,410.26	$4,412.32	$3,393.79	$27,993.73								
6		COG 1	$0.6636	$11,620.79						$11,620.79								
7		COG 2	$0.6636		$13,443.41					$13,443.41								
8		COG 3	$0.6636			$16,646.80				$16,646.80								
9		COG 4	$0.6636				$15,271.15			$15,271.15								
10		COG 5	$0.6636					$12,454.35		$12,454.35								
11		COG 6	$0.6636						$9,579.42	$9,579.42								
12		LDAC	$0.0374	$654.94	$757.66	$938.20	$860.67	$701.92	$539.89	$4,453.28								
13	**Summer 2025**																	
14	Customer Charge	units @	$ 1,350.00								$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$ 1,350.00	$1,350.00	$8,100.00	
15	All	units @	$0.2182								$1,802.98	$1,056.44	$913.16	$1,059.83	$1,271.05	$1,869.18	$7,972.63	
16	All	RDAC	$0.0008								$6.61	$3.87	$3.35	$3.89	$4.66	$6.85	$29.23	
17		Total Base Rates	$0.2190								$1,809.59	$1,060.31	$916.51	$1,063.71	$1,275.71	$1,876.03	$8,001.86	
16		COG 1	$0.4624								$3,820.80						$3,820.80	
17		COG 2	$0.4624									$2,238.76					$2,238.76	
18		COG 3	$0.4624										$1,935.13				$1,935.13	
19		COG 4	$0.4624											$2,245.94			$2,245.94	
20		COG 5	$0.4624												$2,693.56		$2,693.56	
21		COG 6	$0.4624													$3,961.08	$3,961.08	
22	Summer Period Weighted Avg. COG		$0.4624															
23		LDAC	$ 0.0374								$309.03	$181.08	$156.52	$181.66	$217.86	$320.38	$1,366.53	
24			**TOTAL**	$17,742.73	$20,313.79	$24,832.62	$22,892.08	$18,918.59	$14,863.10	**$119,562.92**	$ 7,289.42	$ 4,830.14	$ 4,358.15	$ 4,841.31	$ 5,537.13	$ 7,507.49	$ 34,363.65	$153,926.57
	Base Rate Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	Base Rate Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	RDAC Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	RDAC Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**								
	COG Change Winter		**$ Change**	($1,341.40)	($1,172.96)	($835.35)	($766.32)	$2,691.31	-$3,483.29	**($4,908.01)**								
			% Change	-7.04%	-5.47%	-3.25%	-3.24%	16.58%	-18.98%	**-3.94%**								
	LDAC Change Winter		**$ Change**	$21.01	$24.31	($2.51)	($2.30)	($1.88)	($1.44)	**$37.19**								
			% Change	0.110%	0.113%	-0.010%	-0.010%	-0.012%	-0.008%	**0.03%**								

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
25				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
26		Typical Usage: therms		17,512	20,258	25,086	23,013	18,768	14,436	119,072	8,263	4,842	4,185	4,857	5,825	8,566	36,538	155,610
27	**Winter 2023 - 2024**																	
28	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00								
29	All	units @	$0.2182	$3,821.06	$4,420.36	$5,473.67	$5,021.35	$4,095.15	$3,149.83	$25,981.42								
30	All	RDAC	$0.0169	$295.95	$342.37	$423.95	$388.91	$317.18	$243.96	$2,012.31								
31		Total Base Rates	$0.2351	$4,117.01	$4,762.73	$5,897.62	$5,410.26	$4,412.32	$3,393.79	$27,993.73								
32		COG 1	$0.7402	$12,962.19						$12,962.19								
33		COG 2	$0.7215		$14,616.36					$14,616.36								
34		COG 3	$0.6969			$17,482.15				$17,482.15								
35		COG 4	$0.6969				$16,037.47			$16,037.47								
36		COG 5	$0.5202					$9,763.04		$9,763.04								
37		COG 6	$0.9049						$13,062.72	$13,062.72								
38	Winter Period Weighted Avg. COG		$0.7048															
39		LDAC	$ 0.0362	$633.92	$733.35					$1,367.28								
40		LDAC 2, January 1	$ 0.0375			$940.71	$862.97	$703.79	$541.33	$3,048.81								
41																		
42	**Summer 2024**																	
43	Customer Charge**	units @	$ 1,350.00								$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00	
44	All	units @	$0.2182								$1,802.98	$1,056.44	$913.16	$1,059.83	$1,271.05	$1,869.18	$7,972.63	
45	All	RDAC	$0.0008								$6.61	$3.87	$3.35	$3.89	$4.66	$6.85	$29.23	
		Total Base Rates	$0.2190								$1,809.59	$1,060.31	$916.51	$1,063.71	$1,275.71	$1,876.03	$8,001.86	
46		COG 1	$0.4074								$3,366.33						$3,366.33	
47		COG 2	$0.4074									$1,972.47					$1,972.47	
48		COG 3	$0.4074										$1,704.96				$1,704.96	
49		COG 4	$0.4074											$1,978.80			$1,978.80	
50		COG 5	$0.4074												$2,373.18		$2,373.18	
51		COG 6	$0.4074													$3,489.93	$3,489.93	
52	Summer Period Weighted Avg. COG		$0.4074															
53		LDAC	$ 0.0375								$309.86	$181.56	$156.94	$182.14	$218.44	$321.24	$1,370.18	
54			**TOTAL**	$19,063.12	$21,462.44	$25,670.48	$23,660.70	$16,229.16	$18,347.84	**$124,433.74**	$6,835.78	$4,564.34	$4,128.40	$4,574.65	$5,217.33	$7,037.20	$32,357.70	$156,791.44
55			**Change**	($1,320.38)	($1,148.65)	($837.86)	($768.62)	$2,689.43	($3,484.74)	**($4,870.81)**	$453.64	$265.80	$229.75	$266.66	$319.80	$470.29	**$2,005.95**	($2,864.87)
56			**% Chg**	-6.93%	-5.35%	-3.26%	-3.25%	16.57%	-18.99%	**-3.91%**	6.64%	5.82%	5.57%	5.83%	6.13%	6.68%	**6.20%**	-1.83%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-50 Commercial & Industrial Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		153	184	199	232	205	180	1,153	167	148	151	160	152	148	926	2,079
3	**Winter 2024 - 2025**																	
4	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00								
5	All	units @	$0.2338	$35.80	$42.93	$46.43	$54.30	$47.99	$42.18	$269.63								
6	All	RDAC	($0.0112)	($1.71)	($2.06)	($2.22)	($2.60)	($2.30)	($2.02)	($12.92)								
7		Total Base Rates	$0.2226	$34.08	$40.87	$44.21	$51.70	$45.69	$40.16	$256.71								
6		COG 1	$0.6135	$93.93						$93.93								
7		COG 2	$0.6135		$112.65					$112.65								
8		COG 3	$0.6135			$121.84				$121.84								
9		COG 4	$0.6135				$142.50			$142.50								
10		COG 5	$0.6135					$125.92		$125.92								
11		COG 6	$0.6135						$110.68	$110.68								
12		LDAC	$0.0374	$5.73	$6.87	$7.43	$8.69	$7.68	$6.75	$43.13								
13	**Summer 2025**																	
14	Customer Charge	units @	$ 80.00								$ 80.00	$80.00	$80.00	$80.00	$ 80.00	$80.00	$480.00	
15	All	units @	$0.2338								$39.15	$34.58	$35.22	$37.51	$35.47	$34.59	$216.52	
16	All	RDAC	($0.0035)								($0.59)	($0.52)	($0.53)	($0.56)	($0.53)	($0.52)	($3.24)	
17		Total Base Rates	$0.2303								$38.57	$34.06	$34.70	$36.94	$34.93	$34.08	$213.28	
16		COG 1	$0.3197								$53.54						$53.54	
17		COG 2	$0.3197									$47.28					$47.28	
18		COG 3	$0.3197										$48.17				$48.17	
19		COG 4	$0.3197											$51.29			$51.29	
20		COG 5	$0.3197												$48.50		$48.50	
21		COG 6	$0.3197													$47.31	$47.31	
22	Summer Period Weighted Avg. COG		$0.3197															
23		LDAC	$ 0.0374								$6.26	$5.53	$5.63	$6.00	$5.67	$5.53	$34.64	
24			**TOTAL**	$213.74	$240.40	$253.47	$282.89	$259.29	$237.58	**$1,487.36**	$ 178.37	$ 166.87	$ 168.50	$ 174.23	$ 169.10	$ 166.92	$ 1,023.99	$2,511.35
	Base Rate Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	Base Rate Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	RDAC Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	RDAC Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**								
	COG Change Winter		**$ Change**	($6.92)	($4.87)	($0.38)	($0.44)	$35.88	-$37.87	**($14.59)**								
			% Change	-3.14%	-1.99%	-0.15%	-0.16%	16.06%	-13.75%	**-0.97%**								
	LDAC Change Winter		**$ Change**	$0.18	$0.22	($0.02)	($0.02)	($0.02)	($0.02)	**$0.32**								
			% Change	0.08%	0.09%	-0.01%	-0.01%	-0.01%	-0.01%	**0.02%**								
25				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
26		Typical Usage: therms		153	184	199	232	205	180	1,153	167	148	151	160	152	148	926	2,079
27	**Winter 2023 - 2024**																	
28	Customer Charge	units @	$ 80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00								
29	All	units @	$0.2338	$35.80	$42.93	$46.43	$54.30	$47.99	$42.18	$269.63								
30	All	RDAC	($0.0112)	($1.71)	($2.06)	($2.22)	($2.60)	($2.30)	($2.02)	($12.92)								
31		Total Base Rates	$0.2226	$34.08	$40.87	$44.21	$51.70	$45.69	$40.16	$256.71								
32		COG 1	$0.6587	$100.85						$100.85								
33		COG 2	$0.6400		$117.52					$117.52								
34		COG 3	$0.6154			$122.22				$122.22								
35		COG 4	$0.6154				$142.94			$142.94								
36		COG 5	$0.4387					$90.05		$90.05								
37		COG 6	$0.8234						$148.54	$148.54								
38	Winter Period Weighted Avg. COG		$0.6262															
39		LDAC	$ 0.0362	$5.54	$6.65					$12.19								
40		LDAC 2, January 1	$ 0.0375			$7.45	$8.71	$7.70	$6.77	$30.62								
41																		
42	**Summer 2024**																	
43	Customer Charge**	units @	$ 80.00								$80.00	$80.00	$80.00	$80.00	$80.00	$80.00	$480.00	
44	All	units @	$0.2338								$39.15	$34.58	$35.22	$37.51	$35.47	$34.59	$216.52	
45	All	RDAC	($0.0035)								($0.59)	($0.52)	($0.53)	($0.56)	($0.53)	($0.52)	($3.24)	
46		Total Base Rates	$0.2303								$38.57	$34.06	$34.70	$36.94	$34.93	$34.08	$213.28	
47		COG 1	$0.2895								$48.48						$48.48	
48		COG 2	$0.2895									$42.81					$42.81	
49		COG 3	$0.2895										$43.62				$43.62	
50		COG 4	$0.2895											$46.44			$46.44	
51		COG 5	$0.2895												$43.91		$43.91	
52		COG 6	$0.2895													$42.84	$42.84	
53	Summer Period Weighted Avg. COG		$0.2895															
54		LDAC	$ 0.0375								$6.28	$5.55	$5.65	$6.02	$5.69	$5.55	$34.73	
55			**TOTAL**	$220.47	$245.04	$253.87	$283.35	$223.43	$275.46	**$1,501.63**	$173.33	$162.42	$163.96	$169.40	$164.54	$162.46	$996.11	$2,497.74
56			**Change**	($6.74)	($4.65)	($0.40)	($0.46)	$35.86	($37.88)	**($14.27)**	$5.04	$4.45	$4.53	$4.83	$4.57	$4.45	**$27.88**	$13.61
57			**% Chg**	-3.06%	-1.90%	-0.16%	-0.16%	16.05%	-13.75%	**-0.95%**	2.91%	2.74%	2.77%	2.85%	2.78%	2.74%	**2.80%**	0.54%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1																		
2		Typical Usage: therms (*)		1,505	1,739	1,817	2,137	1,875	1,611	10,685	1,438	1,198	1,173	1,164	1,117	1,300	7,391	18,076
3	**Winter 2024 - 2025**																	
4	Customer Charge	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00								
5	All	units @	$0.1763	$265.39	$306.62	$320.38	$376.81	$330.58	$284.05	$1,883.82								
6	All	RDAC	($0.0112)	($16.86)	($19.48)	($20.35)	($23.94)	($21.00)	($18.04)	($119.68)								
7		Total Base Rates	$0.1651	$248.53	$287.14	$300.03	$352.87	$309.58	$266.00	$1,764.15								
8		COG 1	$0.6135	$923.52						$923.52								
9		COG 2	$0.6135		$1,067.00					$1,067.00								
10		COG 3	$0.6135			$1,114.89				$1,114.89								
11		COG 4	$0.6135				$1,311.24			$1,311.24								
12		COG 5	$0.6135					$1,150.36		$1,150.36								
13		COG 6	$0.6135						$988.44	$988.44								
14		LDAC	$0.0374	$56.30	$65.05	$67.97	$79.94	$70.13	$60.26	$399.63								
15	**Summer 2025**																	
16	Customer Charge	units @	$ 225.00								$ 225.00	$225.00	$225.00	$225.00	$ 225.00	$225.00	$1,350.00	
17	All	units @	$0.1763								$253.57	$211.18	$206.85	$205.24	$196.99	$229.21	$1,303.06	
18	All	RDAC	($0.0035)								($5.03)	($4.19)	($4.11)	($4.07)	($3.91)	($4.55)	($25.87)	
19		Total Base Rates	$0.1728								$248.54	$206.99	$202.75	$201.17	$193.08	$224.66	$1,277.19	
18		COG 1	$0.3197								$459.82						$459.82	
19		COG 2	$0.3197									$382.96					$382.96	
20		COG 3	$0.3197										$375.10				$375.10	
21		COG 4	$0.3197											$372.19			$372.19	
22		COG 5	$0.3197												$357.23		$357.23	
23		COG 6	$0.3197													$415.65	$415.65	
24		Summer Period Weighted Avg. COG	$0.3197															
25		LDAC	$ 0.0374								$53.79	$44.80	$43.88	$43.54	$41.79	$48.63	$276.43	
26			TOTAL	$1,453.35	$1,644.18	$1,707.89	$1,969.04	$1,755.07	$1,539.70	**$10,069.23**	$ 987.15	$ 859.75	$ 846.73	$ 841.89	$ 817.10	$ 913.94	$ 5,266.56	$15,335.79

			Nov	Dec	Jan	Feb	Mar	Apr	Winter
Base Rate Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Base Rate Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RDAC Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
RDAC Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Total Base Rate Change	**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
	Total Base Rate Change	**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
COG Change Winter		**$ Change**	($68.04)	($46.09)	($3.45)	($4.06)	$327.76	-$338.18	**-$132.06**
		% Change	-4.48%	-2.73%	-0.20%	-0.21%	22.96%	-18.01%	**-1.29%**
LDAC Change Winter		**$ Change**	$1.81	$2.09	($0.18)	($0.21)	($0.19)	($0.16)	**$3.15**
		% Change	0.12%	0.12%	-0.01%	-0.01%	-0.01%	-0.01%	**0.03%**

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
25																		
26		Typical Usage: therms		1,505	1,739	1,817	2,137	1,875	1,611	10,685	1,438	1,198	1,173	1,164	1,117	1,300	7,391	18,076
27	**Winter 2023 - 2024**																	
28	Customer Charge	units @	$ 225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00								
29	All	units @	$0.1763	$265.39	$306.62	$320.38	$376.81	$330.58	$284.05	$1,883.82								
30	All	RDAC	($0.0112)	($16.86)	($19.48)	($20.35)	($23.94)	($21.00)	($18.04)	($119.68)								
31		Total Base Rates	$0.1651	$248.53	$287.14	$300.03	$352.87	$309.58	$266.00	$1,764.15								
32		COG 1	$0.6587	$991.56						$991.56								
33		COG 2	$0.6400		$1,113.08					$1,113.08								
34		COG 3	$0.6154			$1,118.34				$1,118.34								
35		COG 4	$0.6154				$1,315.30			$1,315.30								
36		COG 5	$0.4387					$822.60		$822.60								
37		COG 6	$0.8234						$1,326.63	$1,326.63								
38		Winter Period Weighted Avg. COG	$0.6259															
39		LDAC	$ 0.0362	$54.49	$62.96					$117.45								
40		LDAC 2, January 1	$ 0.0375			$68.15	$80.15	$70.32	$60.42	$279.03								
41																		
42	**Summer 2024**																	
43	Customer Charge**	units @	$ 225.00								$225.00	$225.00	$225.00	$225.00	$225.00	$225.00	$1,350.00	
44	All	units @	$0.1763								$253.57	$211.18	$206.85	$205.24	$196.99	$229.21	$1,303.06	
45	All	RDAC	($0.0035)								($5.03)	($4.19)	($4.11)	($4.07)	($3.91)	($4.55)	($25.87)	
46		Total Base Rates	$0.1728								$248.54	$206.99	$202.75	$201.17	$193.08	$224.66	$1,277.19	
47		COG 1	$0.2895								$416.38						$416.38	
48		COG 2	$0.2895									$346.78					$346.78	
49		COG 3	$0.2895										$339.67				$339.67	
50		COG 4	$0.2895											$337.03			$337.03	
51		COG 5	$0.2895												$323.48		$323.48	
52		COG 6	$0.2895													$376.39	$376.39	
53		Summer Period Weighted Avg. COG	$0.2895															
54		LDAC	$ 0.0375								$53.94	$44.92	$44.00	$43.66	$41.90	$48.76	$277.17	
55			TOTAL	$1,519.58	$1,688.18	$1,711.52	$1,973.31	$1,427.49	$1,878.05	**$10,198.14**	$943.86	$823.69	$811.42	$806.85	$783.47	$874.81	$5,044.09	$15,242.23
56			Change	($66.23)	($44.00)	($3.63)	($4.27)	$327.58	($338.34)	**($128.91)**	$43.29	$36.06	$35.32	$35.04	$33.63	$39.13	**$222.47**	$93.56
57			% Chg	-4.36%	-2.61%	-0.21%	-0.22%	22.95%	-18.02%	**-1.26%**	4.59%	4.38%	4.35%	4.34%	4.29%	4.47%	**4.41%**	0.61%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-52 Commercial & Industrial Bill

Comparison of Winter 2024-2025 vs. Winter 2023-2024

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		51,851	45,376	47,252	43,875	44,442	40,295	273,091	38,452	32,161	33,533	41,062	38,634	40,261	224,104	497,195
3	**Winter 2024 - 2025**																	
4	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00								
5	All	units @	$0.1791	$9,286.55	$8,126.76	$8,462.81	$7,858.07	$7,959.54	$7,216.85	$48,910.58								
6	All	RDAC	($0.0112)	($580.73)	($508.21)	($529.22)	($491.40)	($497.75)	($451.30)	($3,058.62)								
7		Total Base Rates	$0.1679	$8,705.81	$7,618.55	$7,933.59	$7,366.66	$7,461.80	$6,765.54	$45,851.96								
8		COG 1	$0.6135	$31,810.70						$31,810.70								
9		COG 2	$0.6135		$27,837.89					$27,837.89								
10		COG 3	$0.6135			$28,989.03				$28,989.03								
11		COG 4	$0.6135				$26,917.50			$26,917.50								
12		COG 5	$0.6135					$27,265.11		$27,265.11								
13		COG 6	$0.6135						$24,721.03	$24,721.03								
14		LDAC	$0.0374	$1,939.23	$1,697.05	$1,767.22	$1,640.94	$1,662.13	$1,507.04	$10,213.60								
15	**Summer 2025**																	
16	Customer Charge	units @	$ 1,350.00								$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$ 1,350.00	$1,350.00	$8,100.00	
17	All	units @	$0.1094								$4,206.64	$3,518.45	$3,668.53	$4,492.18	$4,226.59	$4,404.54	$24,516.94	
18	All	RDAC	($0.0035)								($134.58)	($112.56)	($117.37)	($143.72)	($135.22)	($140.91)	($784.36)	
19		Total Base Rates	$0.1059								$4,072.06	$3,405.89	$3,551.17	$4,348.46	$4,091.37	$4,263.62	$23,732.57	
20		COG 1	$0.3197								$12,293.08						$12,293.08	
21		COG 2	$0.3197									$10,281.99					$10,281.99	
22		COG 3	$0.3197										$10,720.57				$10,720.57	
23		COG 4	$0.3197											$13,127.51			$13,127.51	
24		COG 5	$0.3197												$12,351.38		$12,351.38	
25		COG 6	$0.3197													$12,871.39	$12,871.39	
26	Summer Period Weighted Avg. COG		$0.3197															
27		LDAC	$ 0.0374								$1,438.10	$1,202.84	$1,254.14	$1,535.72	$1,444.92	$1,505.76	$8,381.48	
28			**TOTAL**	$43,805.75	$38,503.49	$40,039.84	$37,275.10	$37,739.03	$34,343.61	**$231,706.81**	$19,153.24	$16,240.72	$16,875.88	$20,361.69	$19,237.68	$19,990.77	$111,859.98	$343,566.79
	Base Rate Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	Base Rate Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	RDAC Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	RDAC Change Winter		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	Total Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
	Total Base Rate Change		**% Change**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	COG Change Winter		**$ Change**	($2,343.67)	($1,202.45)	($89.78)	($83.36)	$7,768.44	($8,457.94)	**($4,408.76)**								
			% Change	-5.09%	-3.03%	-0.22%	-0.22%	25.92%	-19.76%	-1.87%								
	LDAC Change Winter		**$ Change**	$62.22	$54.45	($4.73)	($4.39)	($4.44)	($4.03)	**$99.09**								
			% Change	0.14%	0.14%	-0.01%	-0.01%	-0.01%	-0.01%	0.04%								
29				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
30		Typical Usage: therms		51,851	45,376	47,252	43,875	44,442	40,295	273,091	38,452	32,161	33,533	41,062	38,634	40,261	224,104	497,195
31	**Winter 2023 - 2024**																	
32	Customer Charge	units @	$ 1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00								
33	All	units @	$0.1791	$9,286.55	$8,126.76	$8,462.81	$7,858.07	$7,959.54	$7,216.85	$48,910.58								
34	All	RDAC	($0.0112)	($580.73)	($508.21)	($529.22)	($491.40)	($497.75)	($451.30)	($3,058.62)								
35		Total Base Rates	$0.1679	$8,705.81	$7,618.55	$7,933.59	$7,366.66	$7,461.80	$6,765.54	$45,851.96								
36		COG 1	$0.6587	$34,154.38						$34,154.38								
37		COG 2	$0.6400		$29,040.35					$29,040.35								
38		COG 3	$0.6154			$29,078.80				$29,078.80								
39		COG 4	$0.6154				$27,000.86			$27,000.86								
40		COG 5	$0.4387					$19,496.66		$19,496.66								
41		COG 6	$0.8234						$33,178.96	$33,178.96								
42	Winter Period Weighted Avg. COG		$0.6296															
43		LDAC	$ 0.0362	$1,877.01	$1,642.59					$3,519.61								
44		LDAC 2, January 1	$ 0.0375			$1,771.95	$1,645.32	$1,666.57	$1,511.07	$6,594.91								
45																		
46	**Summer 2024**																	
47	Customer Charge**	units @	$ 1,350.00								$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$1,350.00	$8,100.00	
48	All	units @	$0.1094								$4,206.64	$3,518.45	$3,668.53	$4,492.18	$4,226.59	$4,404.54	$24,516.94	
49	All	RDAC	($0.0035)								($134.58)	($112.56)	($117.37)	($143.72)	($135.22)	($140.91)	($784.36)	
50		Total Base Rates	$0.1059								$4,072.06	$3,405.89	$3,551.17	$4,348.46	$4,091.37	$4,263.62	$23,732.57	
51		COG 1	$0.2895								$11,131.83						$11,131.83	
52		COG 2	$0.2895									$9,310.72					$9,310.72	
53		COG 3	$0.2895										$9,707.87				$9,707.87	
54		COG 4	$0.2895											$11,887.44			$11,887.44	
55		COG 5	$0.2895												$11,184.63		$11,184.63	
56		COG 6	$0.2895													$11,655.51	$11,655.51	
57	Summer Period Weighted Avg. COG		$0.2895															
58		LDAC	$ 0.0375								$1,441.95	$1,206.05	$1,257.50	$1,539.82	$1,448.79	$1,509.78	$8,403.89	
59			**TOTAL**	$46,087.21	$39,651.49	$40,134.34	$37,362.85	$29,975.03	$42,805.57	**$236,016.49**	$17,995.84	$15,272.66	$15,866.53	$19,125.73	$18,074.79	$18,778.92	$105,114.46	$341,130.95
60			**Change**	($2,281.45)	($1,148.00)	($94.50)	($87.75)	$7,764.00	($8,461.97)	**($4,309.67)**	$1,157.40	$968.06	$1,009.35	$1,235.97	$1,162.89	$1,211.85	**$6,745.52**	$2,435.85
61			**% Chg**	-4.95%	-2.90%	-0.24%	-0.23%	25.90%	-19.77%	**-1.83%**	6.43%	6.34%	6.36%	6.46%	6.43%	6.45%	**6.42%**	0.71%

*-Note- Weighted by usage. Actual Weather Normalized.
** Effective August 1, 2022 the Customer Charge increased to $225.00.

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response:

Request No. DOE 1-16:

Reference: Sept 17, 2024, filing

Has the transfer in ownership of the Portland Natural Gas Transmission System (PNGTS) caused an adverse effect on rates, terms, operations, or services of Northern and if yes, please provide a narrative description of the changes in rates, terms, operations, or services caused by the change of ownership of PNGTS.

Response:

Northern has experienced no adverse effect on rates, terms, operations, or services caused by the transfer in ownership of PNGTS.

Person Responsible: Francis Wells **Date:** 10/3/2024

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response: 10/4/2024

Request No. DOE 1-17:

Reference: Docket No. DG 23-087, and Settlement Agreement therein regarding quarterly reports to be issued by the Company to the DOE.

Northern provided the first of the quarterly reports on June 7, 2024; the report was undated and unsigned and was—from the Department's perspective--two months delayed. Moreover, the next (2nd) quarterly report was to be filed in August (covering May June and July) and therefore is delayed. When will Northern provide the second quarterly report?

The Settlement Agreement states p 8 para 7 – *"Decision points include, **but are not limited to**, unfavorable regulatory decisions, a material increase in actual or projected project costs, and material changes in cost allocation due to decisions or actions of transporters. See Confidential Attachment A. The Company agrees to provide quarterly updates to the Department and OCA until such time that all conditions precedent in the 2027 SCPL PA are satisfied or waived and until the Company enters into a Firm Transportation Service Contract for service **from November 2027** through March 2054 with TCPL."* (emphasis added). From the Department's perspective a two-year delay in construction is a "decision point." Please provide an updated list of decision points and deadlines associated with what the June 7 quarterly report identified as a two –year delay.

Please clarify that Northern's quarterly report references the updated (amended) Settlement Agreement, and not the agreement as originally filed.

In light of the two-year delay, does the Company proposed to update the Settlement Agreement and Confidential Attachment A as filed in Docket No. DG 23-087? Why or why not? If yes, when does the Company propose to update the document?

Response:

Northern filed its quarterly report for the second quarter of 2024, the first full quarter after the Commission's Order in docket DG 23-087, on June 7, 2024. This report incorporated information discussed during internal meetings regarding the Empress Capacity Project held in March, April, May, and June 2024. Furthermore, the Company submitted an update to the Public Utilities Commission on July 1, 2024 explaining certain amendments to the Empress Capacity Agreements, and attaching the amendments for reference by the Commission and all parties to the docket. The Company anticipates receiving an updated spend profile related to the Empress

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response: 10/4/2024

Capacity Project on or about October 7, 2024 and will file its report for the Third Quarter shortly thereafter. The Company believes that this information, though technically received after the end of the third quarter, will be valuable to the Department of Energy.

The Department of Energy's question states: "From the Department's perspective a two-year delay in construction is a "decision point."' The Company clarifies that there has not been a "two-year delay in construction." As the Company explained in its July 1, 2024 letter to the Commission, TransCanada PipeLines Limited ("TCPL") expected to construct new facilities to support its capacity offering beginning November 1, 2027. As such, the 2024 TCPL Precedent Agreement and TCPL Agreement anticipated service from April 1, 2024 through October 31, 2027, and the 2027 TCPL Precedent Agreement 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 Precedent Agreement on a date after November 1, 2027, and that service under the TCPL Agreement may therefore extend beyond October 31, 2027. See DG 23-087, Petition Attachment 4 at 1 (noting that the 2027 TCPL PA "commits [Northern] to enter into a Firm Transportation service agreement for commencement on November 1, 2027 *or as soon as possible thereafter*."); Petition Attachment 5 at 4 (indicating that service under the TCPL Agreement may extend past October 31, 2027); Petition Attachment 6 (Redacted) at 1 (stating, in Recital C of the 2027 TCPL Precedent Agreement, that the in-service date would be "November 1, 2027 or as soon as possible thereafter.").

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. This is a modification in project scope, and not a "delay in construction." 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. A copy of TCPL's June 10, 2024 letter was included as Attachment 1 to Northern's July 1, 2024 letter to the Commission.

Included with Northern's letter were amendments modifying the TCPL Agreement and 2027 TCPL Precedent Agreement to (1) reflect the new termination date of TCPL's operational arrangements (October 31, 2029) and by extension the termination date of the TCPL Agreement; (2) reflect the new target In-Service date (November 1, 2029); (3) amend the sunset date in Section 13(h)(i) and Section 13(h)(ii) of the 2027 TCPL Precedent Agreement to May 1, 2029; and (4) amend the date for internal approvals in Section 13(k) of the 2027 TCPL Precedent Agreement to April 1, 2026.

Northern Utilities, Inc.
DG 24-102
Winter 2024-2025 and Summer 2025 Cost of Gas, Department of Energy (DOE)
Data Request Set 1

Date Request Received: 9/23/24 Date of Response: 10/4/2024

As the Company explained in its July 1, 2024 letter, it does not believe the above-described amendments were "decision points" as described in the Settlement Agreement and Order. nevertheless, the Company promptly brought them to the attention of the Commission's and the parties to DG 23-087, including the Department of Energy. **The above-described amendments do not result in any disruption to the firm service obligations under the TCPL Agreement; do not affect pricing under the Empress Capacity Agreements; and do not extend the combined term of the Empress Capacity Agreements beyond the 30-year period previously approved by the Commission.** The volumes available to the Company and the price paid by the Company under the Agreements remain unchanged during the full 30-year period. As such, there is no impact to Northern's customers as a result of the Amendments. Furthermore, the change to the in-service date in the 2027 TCPL PA will result in a reduction to the near-term project expenditures, as shown on the updated exposure profile enclosed as Attachment 4 to the Company's July 1, 2024 letter.

In light of the foregoing, the Company does not propose, or intend to propose, any change in the Settlement Agreement approved by the Commission in DG 23-087.

DOE 1-17 Attachment 1 CONFIDENTIAL provides an updated list of decision points reflecting the amendments to the Empress Capacity Agreements filed with the Commission on July 1, 2024.

Person Responsible: Francis Wells **Date:** 10/4/2024