REDACTED

Northern Utilities, Inc.

2023 Integrated Resource Plan

5-Year Natural Gas Portfolio Plan

Submitted jointly to the Maine Public Utilities Commission and
New Hampshire Public Utilities Commission

Submitted

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I. Executive Summary

The purpose of this Integrated Resource Plan ("IRP", "Plan" or "2023 IRP") filing is to review Northern Utilities, Inc.'s ("Northern" or the "Company") projected long-term resource needs over the coming five year planning period (2023/24 – 2026/27) and review the planning processes used by Northern to develop a natural gas portfolio that provides reliable service to customers at a reasonable cost.

The 2023 IRP provides details regarding the development of the demand forecast, including reductions for target energy efficiency savings, total system throughput under design (cold) weather conditions and conversion of the demand forecast into long-term planning load requirements. The IRP then reviews the current portfolio of long-term assets and compares the supplies available from the current portfolio to the forecast of planning load requirements in order to assess incremental resource needs. Potential supply alternatives are reviewed and the Company's long-term resource decision making process is explained.

The IRP documents current market dynamics, including state energy policy and legislation in Maine and New Hampshire, in order to establish a context for possible long-term contracting activity, Northern's current forecast of resource requirements over the planning period, and the analytical framework Northern uses to evaluate potential new resources.

The forecast of firm customer demand and the subsequent determination of planning load requirements establish the resource need that Northern expects to meet over the planning horizon. Northern developed a detailed demand forecast based on separate models of customer segment demand (*e.g.,* Residential customers,) for the Maine Division and New Hampshire Division. The demand forecasts were adjusted for expected energy efficiency savings and translated into city gate throughput requirements. In addition, the Company's demand forecast was calibrated to reflect extreme cold, or design, weather conditions. Northern uses a design planning standard of 1 occurrence in 30 year probability for supply planning, which is comparable to other LDCs in the region. Forecasts of planning load were developed for normal year, design year and design day conditions.

Table I-1 shows Northern's customer count forecast for the five-year planning period, which reflects an average annual growth rate of almost 2 percent or the addition of nearly 4,300 customers over the forecast period.

Table I-1: Northern Projected Customer Counts

Gas Year	Residential Customers	C&I LLF Customers	C&I HLF Customers	Division Customers
2022/23	54,451	14,345	2,321	71,117
2023/24	55,549	14,474	2,324	72,347
2024/25	56,612	14,620	2,328	73,560
2025/26	57,681	14,773	2,332	74,787
2026/27	58,748	14,920	2,336	76,004
CAGR	1.9%	1.0%	0.2%	1.7%

Table I-2 presents the forecast of Northern's Design Year throughput, which is projected to increase at average annual rates of 1.5 percent, resulting in additional throughput of approximately 2 Bcf annually and 22,000 Dth on design day.

Table I-2: Design Year Throughput (Dth)

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2022/23	221,208,322	22,152,715	12,489	243,342	22,408,545
2023/24	223,978,882	22,425,798	12,924	246,772	22,685,493
2024/25	226,920,671	22,720,278	12,924	250,134	22,983,336
2025/26	229,652,509	22,994,149	12,924	253,313	23,260,386
2026/27	232,215,268	23,250,691	12,924	256,323	23,519,938
CAGR	1.2%	1.2%	0.9%	1.3%	1.2%

Since Northern operates an unbundled system, the Company's planning load includes only the demand of customers for whom the Company has planning authority. The Company's planning load includes: (i) the natural gas demand of customers who continue to take supply from the Company; and (ii) those customers who receive natural gas supply from competitive suppliers but are assigned capacity pursuant to Northern's tariffs. The resource requirement for customer demands not included in planning load is managed by the customer and their marketer.

Table I-3: Design Year Planning Load (Dth)

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2022/23	22,408,545	5,305,121	59,968	17,043,456
2023/24	22,685,493	5,454,484	62,043	17,168,966
2024/25	22,983,336	5,516,900	62,803	17,403,633
2025/26	23,260,386	5,568,744	63,462	17,628,180
2026/27	23,519,938	5,615,019	64,068	17,840,850
CAGR	1.2%	1.4%	1.7%	1.1%

In the IRP, Northern compares the Planning Load forecast under design weather conditions to the supplies available from its portfolio of long-term natural gas supply resources to identify incremental resource requirements, and inform capacity renewal decisions. The comparison indicates that Northern's current resources are insufficient to meet planning load under design conditions during the colder days of the year during the planning period of this IRP. Currently, Northern meets this supply need with supplies delivered by others to its system, though additions of Atlantic Bridge, Portland XPress, and Westbrook Xpress capacity to the portfolio have significantly reduced the Company's reliance upon the availability of delivered supplies.[1]

Given the forecast of planning load and the reliance on delivered supplies, the Company intends to renew all resources subject to renewal during the planning period. These resources or contracts are typically "legacy contracts" (i.e., the costs of the underlying assets are heavily depreciated and therefore less expensive than the cost of new construction). Therefore, these legacy contracts are usually more cost effective capacity than incremental capacity. In addition, certain of the resources or contracts are also associated with natural gas storage that provides significant flexibility and price stability to the portfolio. Finally, certain of the resources and contracts are directly interconnected to Northern thus providing physical delivery of natural gas. Given the lead time required for new pipeline or peaking projects, the Company plans to secure delivered peaking supplies over the coming five year planning period to fill its supply requirements beyond the capabilities of the current long-term portfolio.

Northern monitors new supply alternatives and opportunities by staying informed of developments within the regional natural gas market and maintaining business relationships with pipelines, suppliers and other parties pursuing or offering solutions to supply challenges. These activities help Northern to identify developers and projects that could meet the needs Northern may require. Northern has also explored additional traditional resource additions, such as liquefied natural gas ("LNG") , pipeline and/or underground storage capacity, and delivered peaking supply, as well as alternative supply resources, namely renewable natural gas ("RNG"). The Company continues to explore these resources, and has developed a gas quality standard for potential RNG projects that might interconnect into the Company's distribution system.

As discussed in this IRP, the Company utilizes both quantitative and qualitative approaches to review the different aspects of potential incremental natural gas supply projects. Quantitative tools are used to identify incremental resource needs, model the impact of adding various proxy resources to identify potential resource additions, and to identify and compare costs. As part of the qualitative (i.e.,

[1] "Delivered supplies" refers to natural gas supply that is delivered to Northern by third-parties under their own supply and capacity arrangements. As such, the Company does not exert any control over the supply or capacity used by the third party to provide the service. The price for delivered baseload service is often tied to the New England market index price, which has been significantly more volatile than the indices used by Northern for supplies that feed its pipeline capacity contracts, while the price for delivered peaking supply is negotiable but there are very few sellers so buyers have little leverage.

non-price) review, the Company evaluates the projects across various metrics, including upstream/downstream issues, project development risks, regulatory environment, and rate/toll flexibility and transparency. The Company has also evaluated resources under the framework set forth in RSA 378:38-39 and the guidance provided by the Commission in DG 19-126, Orders No. 26,664 (August 8, 2022) and 26,689 (September 15, 2022). Ultimately, Northern relies primarily on qualitative criteria when making proposed resource decisions, so long as modeled costs of competing projects are reasonably comparable. Northern's primary reliance on qualitative assessment recognizes that price forecasts are subject to change in unpredictable ways and therefore reduces the possibility that major resource decisions are based primarily on price forecasts while ensuring that resource decisions are informed by appropriate selection criteria such as operational characteristics, added diversity or project risk – all of which cannot be adequately modeled.

In DG 19-126, Order No. 26,664, the Commission requested, for the first time in connection with the Northern's natural gas LCIRP, information related to the Company's investments in capital assets. Northern's distribution planning process begins with engineering planning studies that generally cover a ten-year time frame to identify short-term and long-term system needs. These studies serve as the basis for the Company's line-by-line, project-by-project five-year capital budget, which is updated annually. With this LCIRP, Northern provides its current New Hampshire Division capital budget, as well as a 5-year history of actual capital spending. Consistent with the Commission's guidance in Order No. 26,664, Northern has provided the information provided in a "functional view" by major category as well as a "project view" with narrative detail for projects costing $200,000 or more.

Northern serves customers in both Maine and New Hampshire and therefore is regulated by both the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission. Northern enters into transportation, storage and supply contracts on behalf of customers in order to provide reliable service at a reasonable cost. Northern expends extensive effort to assess the soundness of its decision making and provide sufficient supporting data and analysis that is adequate thus allowing regulators and policy makers in both states to understand the considerations evaluated and approve the cost consequences of any proposed contractual commitment.

Lastly, Northern must ensure that new long-term resource decisions are determined by its regulators to promote the public interest, that Northern is granted approval to recover the costs associated with new long-term contracts, and that its regulators will support Northern in the performance of its contractual obligations under new contracts.

In summary, the 2023 IRP is intended to communicate Northern's gas supply planning objective, describe the current market dynamics impacting long-term resource decisions; and the process used by the Company to forecast planning load, identify incremental resource needs and evaluate potential resource alternatives for possible addition to the portfolio.

II. Introduction

Northern Utilities, Inc., a subsidiary of Unitil Corporation, is a local distribution company ("LDC") providing natural gas supply and distribution service to customers in the states of Maine and New Hampshire. Northern's predecessor companies date back over 160 years to the Portland Gas Light Company, which was formed in 1849. In 1979, Northern was acquired by Bay State Gas Company ("Bay State"), and in 1999, Northern and Bay State were acquired by NiSource, Inc. In 2008, Unitil Corporation purchased Northern from NiSource, Inc. As of year-end 2022, Northern provides service to approximately 34,740 customers in southern Maine and to approximately 36,464 customers in the seacoast region of New Hampshire. Northern's highest annual throughput was 20,310,644 Dth, which occurred during the split-year of November 1, 2018 to October 31, 2019. Northern's maximum daily throughput was 158,447 Dth, which occurred on February 3, 2023.

Northern hereby submits its 2023 Integrated Resource Plan ("IRP"), which covers the five-year planning period from November 1, 2023 to October 31, 2028.

A. Structure of the Filing

Northern's 2023 IRP filing is organized as follows:

- Section III, Planning Environment, sets forth the jurisdictional, legal, regulatory, policy and market landscape within which Northern operates, all of which collectively frames the context in which resource planning decisions must be made;
- Section IV, New Hampshire Capital Budget, describes the Company's robust capital budget process, which is designed to provide safe, reliable and affordable service to customers, and presents the Company's detailed 5-year capital budget, which is developed and updated annually.
- Section V, Demand Forecast, describes the methodology and results of Northern's forecast of natural gas demand over the five-year planning horizon (i.e., gas-years from 2023/24 to 2027/284), including development of the Customer Segment Demand models, the modeling of planned Energy Efficiency savings and resulting Normal Year Throughput forecast;
- Section VI, Planning Load Forecast, introduces the planning standards Northern used to develop design condition forecasts, including Design Year and Design Day Throughput, explains the adjustments made relative to the Capacity Assignment provisions of the Delivery Service Tariffs, and provides the methodology and results of the Company's Long-Term Planning Load forecasts;
- Section VII, Current Portfolio, describes the Energy Efficiency resources being implemented in each Division, details the Company's existing long-term Capacity Portfolio and reviews the Company's supply procurement and price risk management practices;

- Section VIII, Resource Balance, provides Normal Year, Design Year and Design Day comparisons of the existing long-term resource portfolio relative to the Company's Long-Term Planning Load forecast to identify portfolio needs over the planning period;
- Section IX, Incremental Resources Options, reviews the limited available long-term resource options that could meet identified portfolio needs, such as incremental Energy Efficiency, traditional gas supplies and alternative gas supplies such as RNG, and reviews the Company's efforts since the prior IRP to identify new resources;
- Section X, Emissions and Public Health, provides summary greenhouse gas and air quality emissions and public health impacts based on the combustion of natural gas by customers using environmental metrics from the EPA.
- Section XI, Preferred Portfolio, describes the Company's approach to long-term portfolio planning and reviews the evaluation methods the Company uses to identify resource needs and compare competing long-term resources;

Additional supporting materials are provided in appendices.

III.Planning Environment

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern is a single company serving customers in the states of Maine and New Hampshire, subject to regulation and oversight in both states. Energy Efficiency programs are developed and delivered differently in Maine and New Hampshire. Retail Choice programs in the two Divisions are similar, which has stabilized the Company's Planning Load, enabling commitments to long-term capacity resources.*
- *Pursuant to State statute and regulatory rulings, Northern files Integrated Resource Plans to keep its regulators and key stakeholders apprised of its decision-making processes in the pursuit of providing safe, reliable service to customers at the lowest reasonable cost.*
- *Energy and environmental policy trends in Maine suggest a continued focus on decarbonization and reducing Greenhouse Gas ("GHG") emissions and the promotion of environmentally friendly heating sources and technologies (specifically heat pumps), to further emissions reduction goals in the state.*
- *Energy and environmental policy trends in New Hampshire suggest a focus on prioritizing cost-effective energy policies, which may include an "all of the above" approach to energy sources, but ultimately are those that enable both business and consumer cost savings and further a reliable and resilient energy system.*
- *Pursuant to the Clean Air Act, the EPA sets limits on certain air pollutants and actively monitors each state's compliance with air quality standards. The Act has led to significant declines in air pollution, and both Maine and New Hampshire are in attainment status. Northern's energy efficiency programs, conversions of oil customers to gas and replacement of leak prone pipe have had favorable impacts on air quality*
- *Current regional market conditions are beset by volatility and supply constraints due to increasing demand for gas while energy and environmental policy pose challenges to new fossil fuel infrastructure. The Company seeks additional supply resources and highly values resource flexibility to ensure it can continue to provide reliable and reasonably priced supply.*

A. Introduction

Section III describes Northern's Planning Environment. The Planning Environment section describes the legal, policy and market landscape within which Northern operates.

This Planning Environment section is organized as follows:

Part B, Jurisdictional Context, explains that Northern is subject to regulation by two state utility commissions, reviews jurisdictional differences in the development and delivery of customer funded energy efficiency, describes the Retail Choice program and its relationship to gas supply planning and explains how costs are allocated among the states;

Part C, Statutory and Regulatory Requirements, reviews the legal and regulatory standards for integrated resource planning with which the Company must comply in each state. Northern has structured its Integrated Resource Plan in order to meet these standards;

Part D, State Energy Policy, provides context regarding the energy and environmental policy objectives and trends in each state, such as ensuring reliability, cost effectiveness and GHG reduction goals;

Part E, Clean Air Act of 1990, reviews the Clean Air Act and its applicability to gas distribution companies, greenhouse gas (GHG) emissions by fuel type and efforts Northern has made to improve the efficiency of its distribution system;

Part F, Regional Market Overview, discusses regional market conditions and recent changes in natural gas demand and supply dynamics to provide context for the Company's resource planning process.

B. Jurisdictional Context

Northern is a single company serving natural gas distribution customers in the states of Maine and New Hampshire and therefore is subject to dual oversight, by both the Maine Public Utilities Commission (MPUC) and the New Hampshire Public Utilities Commission (NHPUC), and to various laws and rules in each jurisdiction.

1. Customer Funded Energy Efficiency

Energy efficiency planning and implementation is developed and administered differently in the two states in which Northern operates. In Maine, energy efficiency is planned and administered centrally by Efficiency Maine Trust. In New Hampshire, Northern participates in a statewide process that identifies statewide and utility specific programs and savings targets. Northern directly designs and delivers approved energy efficiency programs to its customers in New Hampshire.

a) Energy Efficiency in Maine

Ratepayer supported Energy Efficiency programs in Maine are managed and administered by Efficiency Maine Trust ("EMT" or "Efficiency Maine"), which is defined on its website as "a quasi-state agency established to plan and implement energy efficiency programs in Maine." Efficiency Maine collects assessments from Maine natural gas and electric local distribution companies, including Northern, and manages a suite of electric and thermal efficiency programs for the state.

Efficiency Maine prepares and implements a Triennial Plan, subject to the review and oversight of the Maine PUC. The fiscal year 2023-2025 Triennial Plan was filed with the Maine Commission on November 29, 2021.[2] The Maine Public Utilities Commission approved a Stipulation among the parties to Docket 2021-00380 establishing a Fifth Triennial Plan for fiscal years 2023 - 2025.[3]

Legislation passed in 2019 amends 35-A M.R.S. Pt. 8, Ch. 97 to require that an evaluation be undertaken no less than every three years identifying the maximum achievable cost-effective ("MACE") potential for electric and natural gas energy efficiency in Maine.[4] It also provides that certain avoided cost and benefit elements to be included in Efficiency Maine's calculations of cost effectiveness be based on the regional Avoided Energy Supply Components ("AESC") study, which projects the value of the avoided cost of energy use realized by Energy Efficiency programs throughout the region.[5] The AESC Study estimates the marginal value of electricity, natural gas supply, pooled transmission and distribution, oil, propane, kerosene, wood, demand reduction induced price effects, and other resources, and serves as the basis for calculating the lifetime value of energy efficiency programs in all of the New England states, including New Hampshire.

As the largest natural gas distribution company in Maine, Northern participates as an intervenor in the Maine PUC cases in which energy efficiency programs are considered. The Company is called upon to provide customer-related data and other relevant information to assist in the development and implementation of energy efficiency programs and services. As an intervenor, the Company's primary focus is on protecting the interests of its customers and ratepayers and ensuring that they receive energy efficiency program benefits commensurate with the assessment collected from Northern.

b) Energy Efficiency in New Hampshire

The energy efficiency ("EE") programs offered by Northern to its New Hampshire customers are developed as part of a comprehensive, statewide approach to optimizing energy use by natural gas and electricity customers. These programs are jointly marketed across the state under the NHSaves banner. The New Hampshire programs aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors. As such, the energy efficiency environment in New Hampshire, particularly Northern's collaboration with other utilities and stakeholders in the planning process and Northern's direct implementation of approved measures, is very different from the environment in Maine.

On February 24, 2022, HB 549 was signed into law. Among other things, HB 549 amended RSA chapters 374 and 374-F relative to energy efficiency program funding, cost effectiveness, and future energy efficiency filing. Pursuant to RSA 374-F:3, IV, as amended by HB 549, Northern and the other New

[2] See generally Docket 2021-00380.
[3] 2021-00380, Order Approving Stipulation (May 17, 2022).
[4] 35-A M.R.S. § 10104(4)(a).
[5] 35-A M.R.S. § 10110(4-A)(B).

Hampshire electric and natural gas utilities submitted an EE plan for program offerings available from May 1, 2022 through January 1, 2024 (the "2022-2023 Plan"). The Commission approved the 2022-2023 Plan, finding it to be consistent with the directives of HB 549.[6] Northern is currently administering energy efficiency programs in New Hampshire consistent with the 2022-2023 Plan. The Company is currently working with the other New Hampshire electric and natural gas utilities, as well as other interested stakeholders, to develop proposed program offerings for the next triennial period; the next three-year plan will be filed on or before July 1, 2023.[7]

2. Retail Choice Program

The Company operates an unbundled distribution system pursuant to the Delivery Service Terms and Conditions approved by the Maine Public Utilities Commission ("ME Delivery Service Tariff") and the New Hampshire Public Utilities Commission ("NH Delivery Service Tariff", or jointly "Delivery Service Tariffs"). The Delivery Service Tariffs allow commercial and industrial ("C&I") customers to purchase their gas supply from retail suppliers and establish the rules under which retail suppliers deliver supply to Northern's system and under which Northern provides services such as administration, metering and balancing. The Delivery Service Tariffs also establish the parameters under which a C&I customer would be eligible for, or exempt from, the assignment of capacity from the Company's upstream pipeline, storage and on-system peaking resources. For customers that are assigned capacity, the Tariff includes the Capacity Assignment provisions that impact Northern's Planning Load. The Delivery Service Tariff provisions are referred to as the Retail Choice Program. Participating customers are referred to as Delivery Customers, who receive "Delivery Service" from Northern and "Supplier Service" from retail suppliers. Customers who receive supply from Northern are referred to as Sales Customers, who receive "Sales Service", which includes bundled delivery and supply service from Northern.

Consistency in the Delivery Service Tariffs in both states, as well as provisions like the Capacity Ratio and Annual TCQ Review have stabilized the Company's Planning Load, which has allowed the Company to better define its Planning Load obligations and commit to incremental long-term capacity additions to its gas supply portfolio.

The main characteristics of the Retail Choice Program are:

1. Any Customer who received Sales Service from the Company, who then initiates Delivery Service, is assigned capacity with a Total Capacity Quantity (TCQ) equal to 100 percent of the Customer's estimated Peak Day demand times the Capacity Ratio.
2. A Capacity Ratio, equal to the amount of capacity divided by estimated requirements of sales and capacity assigned delivery customers on the Peak Day, is used to allocate capacity proportionately among sales and delivery customers.

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[6] DE 20-092, Order No. 26,621 ("Order on the 2022-2023 New Hampshire Statewide Energy Efficiency Plan") at 1, 36-37 (April 29, 2022).
[7] RSA 374-F:3, VI-a(d)(3).

3. Each delivery customer's TCQ is reviewed annually by re-estimating their Peak Day demand and updating the Capacity Ratio. The customer's TCQ is adjusted if their updated TCQ differs from their prior TCQ by a threshold amount.[8]

4. Any Customer at a new service location who commences Delivery Service within 60 days of initiating service is not assigned capacity, and is therefore Capacity Exempt, subject to an annual usage demonstration threshold of 25,000 therms in the Maine Division.

5. Any Capacity Exempt customer who chooses to receive Sales Service will become subject to Capacity Assignment if they subsequently choose a retail supplier.

6. Retail suppliers are assigned proportionate shares of capacity from Northern's entire capacity portfolio. The majority of assigned capacity is released directly to retail suppliers through each pipeline's Electronic Bulletin Board or comparable process for Canadian resources. A small portion of the assigned capacity is provided as a "Company-Managed" service, which is controlled by the Company. All assigned resources are priced at actual demand and commodity cost.

7. Delivered Supply purchases made by Northern are solely for serving Sales Service customer load, and are not assignable to retail suppliers. Thus, apart from the assignment of limited Company-managed resources, retail suppliers directly control their own supply purchases.

8. Customers who switch from Delivery Service to Sales Service must remain on Sales Service until the subsequent April 30 and pay a commodity-based re-entry charge (for capacity assigned customers) or conversion charge (for capacity exempt customers) during the stay period.

3. Inter Divisional Cost Allocation

Since Northern maintains a single gas supply portfolio to serve customers in both Maine and New Hampshire, it is critical that gas supply cost allocation between the states be well understood and accepted in both states.

Northern utilizes two different methodologies to equitably allocate demand and commodity costs between the Maine and New Hampshire Divisions. Whereas commodity costs are allocated based on each division's percentage of monthly firm sendout, demand costs are allocated utilizing the Modified Proportional Responsibility ("MPR") allocation method. The MPR allocation methodology is designed to equitably assign costs to both sales customers and capacity assigned (non-exempt) delivery customers in each division based on those customers' demand requirements. This methodology assigns costs to each division based on prior year sales and dispatch of resources that are adjusted for design weather conditions. Using a linear optimization model, Northern determines the optimal dispatch of resources (pipeline, storage and peaking) in the design weather conditions. Northern's supply resource costs

[8] In the Maine Division, a customer's TCQ is adjusted if their TCQ changes by more than 5 percent; in the New Hampshire Division, a customer's TCQ is adjusted if their TCQ changes by more than 10 percent.

(pipeline, storage and peaking) are then allocated to each month based on the percentage of the monthly utilization of that resource. This assigns resource costs to each month based on usage. The monthly costs are then allocated to each division based on the percentage of total demand for each division. Once allocated to each division, the monthly costs are then summed with the percentage comprised from each division equaling that division's PR allocator.

The MPR methodology was developed in response to the emergence of retail choice programs in both states and was approved by Maine PUC pursuant to Settlements in Docket Nos. 2005-00098 and 2005-00273, and by the New Hampshire PUC in Docket No. DG 05-080. Approval of the methodology was reiterated in Maine Docket No. 2017-00117 in which, subsequent to the numerous changes made to the Delivery Service Terms and Conditions in Docket No. 2014-00132, the Maine PUC determined that the MPR methodology was still the best method for inter-divisional cost allocation notwithstanding the changes to Northern's retail choice program in Maine. During the pendency of the Maine PUC dockets on retail choice and cost allocation, a New Hampshire PUC initiated an investigation into whether the methodology used by Northern to allocate gas supply costs between New Hampshire and Maine was just and reasonable, Docket No. IR 15-009. In 2018, following the retail choice changes and affirmation of the MPR allocation method in the Maine Division, the investigation was closed.

The approval and support of the MPR methodology from the Maine and New Hampshire Commissions provide Northern with assurance and stability in its long-term planning process and allows the Company to focus on obtaining low cost and reliable resources without the distraction of cost allocation issues.

C. Statutory and Regulatory Requirements

To provide context for the Integrated Resource Plan, this section reviews the respective statutory and regulatory requirements relative to resource planning in each jurisdiction.

1. Maine Regulatory Requirements

There are no statutory requirements to file an Integrated Resource Plan in Maine, and Northern is the only natural gas LDC in Maine that files an IRP. Northern's obligation to file an Integrated Resource Plan with the Maine Commission stems from a Stipulation and Settlement approved by the Maine and New Hampshire Commissions.[9] The Stipulation states:

> *The purpose of the IRP will be to keep the Maine Commission and New Hampshire Commission informed of Northern's forward-looking system planning processes and*

[9] See Maine Dockets 2005-00087 and 2005-00273, Order Part 2 (April 26, 2005); New Hampshire Docket DG 05-080, Order Approving Settlement Agreement (June 1, 2006).

plans. The Maine Commission may provide a hearing process to review the IRP and may provide such advice or consent as the Maine Commission deems proper.[10]

Consistent with the approach that the IRP is intended to keep the respective Commissions informed of Northern's planning processes and activities, during the proceeding in which Northern's 2015 IRP was reviewed in Maine, the Commission treats the Company's IRP filings as informational and has not given affirmative approval of the Company's planning practices.[11]

In addition, the Maine Commission has been willing to review specific long-term capacity commitments for pre-approval. For example, the Maine Commission reviewed and approved Northern commitment to pipeline expansion capacity on the Westbrook Xpress Project, in Docket No. 2019-00101.

Northern terminated its financial hedging program in 2018. In its Order approving the termination of Northern's financial hedging program, the Maine Commission proposed that Northern include in its IRP filing an "in depth discussion of its price risk management objectives and a description of actions it has taken, or will take, to reduce customers' exposures to gas price volatility form year to year." [12] In Section VII.D, Northern describes it approach to price risk management.

2. New Hampshire Statutes and Regulatory Requirements

Pursuant to New Hampshire's Least Cost Energy Planning statute (RSA 378:37-40)[13], Northern, along with all other gas and electric utilities in New Hampshire, must periodically file an IRP with the NH Public Utilities Commission to be reviewed in an adjudicative proceeding.[14]

The Least Cost Energy Planning statute sets forth the energy policy of New Hampshire as follows:

…it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.[15]

As set forth in RSA 378:38, the IRP must include the following: [16]

I. *A forecast of future demand for the utility's service area.*

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[10] Maine Docket Nos. 2005-00087 and 2005-00273, Stipulation and Settlement at 11-12.
[11] Maine Docket No. 2019-00123, Order Closing Docket at 2 (November 19, 2020).
[12] Maine Docket No. 2018-00041, Cost of Gas Factor, May 7, 2018, p.7.
[13] Please see Appendix 6 for the full text of RSA 378:37-40.
[14] RSA 378:38, 39.
[15] RSA 378:37
[16] RSA 378:38

II. *An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.*

III. *An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.*

IV. *An assessment of distribution and transmission requirements, including an assessment of the benefits and costs of "smart grid" technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies.*

V. *An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.*

VI. *An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.*

VII. *An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.*

RSA 378:39 sets forth requirements for the Commission's evaluation of plans as follows: [17]

The commission shall review integrated least-cost resource plans in order to evaluate the consistency of each utility's plan with this subdivision, in an adjudicative proceeding. In deciding whether or not to approve the utility's plan, the commission shall consider potential environmental, economic, and health-related impacts of each proposed option. The commission is encouraged to consult with appropriate state and federal agencies, alternative and renewable fuel industries, and other organizations in evaluating such impacts. The commission's approval of a utility's plan shall not be deemed a pre-approval of any actions taken or proposed by the utility in implementing the plan. Where the commission determines the options have equivalent financial costs, equivalent reliability, and equivalent environmental, economic, and health-related impacts, the following order of energy policy priorities shall guide the commission's evaluation:

I. Energy efficiency and other demand-side management resources;
II. Renewable energy sources;
III. All other energy sources.

In its review of Northern's 2019 IRP, in DG 19-126, the Commission approved a settlement among the Company, the Office of the Consumer Advocate and then New Hampshire Commission Staff establishing a Working Group to develop recommendations to the Commission with respect to Northern's next IRP.[18] Pursuant to the Settlement, the Working Group submitted its report to the Commission on March 31, 2022. The Commission issued an Order that partially adopted the recommendations of the

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17 RSA 378:39
18 Order 26,382. DG 19-126, "Order Approving Settlement Agreement" (July 23, 2020).

Working Group and provided guidance for the Company's next LCIRP. DG 19-126.[19] The guidance from these Orders is summarized below:

1. The Company should provide a "functional" and "project" view of planned capital investments for the coming ten (10) years and historical capital investment for the previous five (5) years in its next LCIRP, to be followed by annual updates.[20]
2. The LCIRP process should not conflict with the Energy Efficiency Resource Plans, which have maximum funding levels set legislatively.
3. Northern should include RNG as a potential supply option, but only if available as a least cost supply.
4. Northern should assess GHG emissions, but only with respect to emissions from Northern's distribution system, while emissions upstream of Northern's system and from downstream customer equipment are considered out of scope.
5. Northern should assess health related impacts of emissions from leakage on its distribution system, leveraging publicly available reports on such impacts.
6. Northern should assess the economic impacts of its distribution system operation system upgrades by reporting on direct jobs attributable to Northern's operations over the past 20 years. If supply options under consideration would create jobs in New Hampshire, Northern should estimate the direct jobs that would be created.
7. Northern should seek opportunities to incorporate Non-Pipeline Alternatives ("NPAs") that could avoid or defer system infrastructure costs, including via truck or rail, CNG and LNG.

Northern has incorporated the requirements of the Least Cost Energy Planning statutes and, where possible, the New Hampshire Commission's guidance in the development of this IRP and has addressed them throughout this report.

D. State Energy Policy

State energy policy may be a function of, among other things, legislative initiatives, State Agency policy recommendations, and Public Utility Commission decisions. Over time, priorities change. Both New Hampshire and Maine periodically review state energy policy, potentially resulting in adjustments or fundamental changes in the direction and implementation of state energy policy.

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[19] DG 19-126, Order No. 26,664 ("Order Following Working Group Report") (August 8, 2022); Order No. 26,689 ("Order on Northern Utilities' Motion for Rehearing") (September 15, 2022).

[20] Order No. 26,664 pp. 11-13, 16-18.

1. Maine Energy Policy

In recent years, Maine has shown an increased focus on State energy policy. For example, in 2009 the Maine Legislature established the Efficiency Maine Trust ("EMT" or "Efficiency Maine") for the purposes of developing, planning, coordinating and implementing energy efficiency and alternative energy resources programs in the State. 35-A M.R.S. § 10103(1). The EMT is tasked with administering cost-effective energy and energy efficiency programs to help individuals and businesses meet their energy needs at the lowest cost by, *inter alia*, reducing the cost of energy to residents of the State, maximizing the use of cost-effective energy efficiency measures, enhancing heating improvements for households of all income levels through implementation of cost-effective efficiency programs, and using cost-effective energy and energy efficiency investments to reduce greenhouse gas emissions. 35-A M.R.S. § 10103(2). The Maine Public Utilities Commission approved the EMT's Fifth Triennial plan for the fiscal years 2023 – 2025, Legislation passed in 2019 amends 35-A M.R.S. Pt. 8, Ch. 97 to require that an evaluation be undertaken no less than every three years identifying the MACE potential for natural gas energy efficiency in Maine.[21] It also provides that certain avoided cost and benefit elements to be included in Efficiency Maine's calculations of cost effectiveness be based on the regional AESC study, which projects the value of the avoided cost of energy use realized by Energy Efficiency programs throughout the region.[22] The AESC Study estimates the marginal value of electricity, natural gas supply, pooled transmission and distribution, oil, propane, kerosene, wood, demand reduction induced price effects, and other resources, and serves as the basis for calculating the lifetime value of energy efficiency programs in all of the New England states, including New Hampshire. Maine energy efficiency is discussed further below.

Other energy policy legislation relevant to natural gas in Maine includes 35-A M.R.S. Pt. 8, Ch. 19, "The Maine Energy Cost Reduction Act" (ECRC). In passing the ECRC, the Maine legislature found that expansion of natural gas transmission capacity into this State and other states in the ISO-NE region could result in lower natural gas prices and, by extension, lower electricity prices for consumers in this State. 35-A M.R.S. § 1903(2). The ECRC authorizes the Maine Commission to execute an energy cost reduction contract or a physical energy storage contract, or both, subject to certain limitations. 35-A M.R.S. § 1904. To date, the Commission has not entered into any contracts under the ECRC. See <u>2014-00071, Order on Petitions for Clarification and Reconsideration at 5-6 (Nov. 21, 2016); 2016-00253, Order at 43 (May 17, 2017)</u>. More recently, the Maine Legislature passed L.D. 1766, "An Act To Transform Maine's Heat Pump Market To Advance Economic Security and Climate Objectives," establishing, among other things, a goal to install 100,000 new high-performance air source heat pumps in Maine by EMT fiscal year 2025 to provide heating in both residential and nonresidential spaces. The Legislature also passed LD 1679, "An Act To Establish the Maine Climate Change Council to Assist Maine to Mitigate, Prepare for and Adapt to Climate Change," which, *inter alia*, creates a "Maine Climate Change Council" and establishes greenhouse gas emissions reduction goals (less than 45% of 1990 levels by January 1, 2030 and less than 80% of 1990

[21] 35-A M.R.S. § 10104(4)(a).
[22] 35-A M.R.S. § 10110(4-A)(B).

levels by January 1, 2050) and energy efficiency goals (achieving electricity and natural gas program savings of at least 20% and heating fuel savings of at least 20% by 2020). In December 2020, the Council presented a final plan, entitled "Maine Won't Wait," which included, *inter alia*, strategies to pursue reduce emissions from transportation, modernize buildings (including weatherization of existing homes and businesses), reduce emissions through clean energy innovation, and grow the state's clean energy economy.[23] As of this writing, more than 82,000 new heat pumps have been installed in Maine since 2019.[24] In this same period, more than 9,100 homes have been weatherized, which is more than halfway toward the plan's goal of weatherizing 17,500 homes by 2025.[25]

In February 2015, the Maine Governor's Energy Office issued an Update to its Comprehensive Energy Plan (the "Update").[26] The Update proposed an overarching energy policy objective of lowering costs for businesses and residential customers and reducing pollution. Update at 3. The Update noted that there had been progress made towards the 2009 Plan goal of expanding access to natural gas, and recommended continuing progress toward reducing heating costs by increasing opportunities for residents to install energy efficiency improvements and more affordable heating systems, including via access to natural gas infrastructure. Update at 8, 10, 14, 15. The Update also recommended that the State continue to pursue a regional solution to natural gas capacity constraints by working regionally, and as an individual state, to successfully expand natural gas transportation infrastructure into New England and into Maine. Id. at 3, 20. With respect to reduction of greenhouse gas emissions, the Update recommends that Maine continue its efforts to increase energy efficiency and replace higher emitting energy sources with renewable energy sources and low carbon emitting natural gas. Id. at 50.

2. New Hampshire Energy Policy

In July 2022, the New Hampshire Department of Energy issued an update to the New Hampshire 10-Year State Energy Strategy.[27] The first State Energy Policy was published in 2014, and subsequently updated in 2018.

The 2022 Update continues to prioritize addressing the high cost of energy and organizing goals around cost-effective energy policies. Goals to improve state energy policy to better meet consumer include, but are not limited to,

1. Prioritizing cost-effective energy policies;
2. Ensuring a secure, reliable, and resilient energy system;
3. Adopting all-resource energy strategies and minimizing government barriers to innovation;
4. Achieving cost-effective energy savings;
5. Achieving environmental protection that is cost-effective and enables economic growth;

[23] "*Maine Won't Wait*, A Four-Year Plan for Climate Action" (December 1, 2020).
[24] "*Maine Won't Wait* Progress Report" at 2 (December 1, 2022).
[25] Id.
[26] The State's previous Comprehensive Energy Plan was issued on January 15, 2009.
[27] See RSA 12-P:7-a.

6. Supporting a robust, market-selection of cost-effective energy resources;
7. Generating in-state economic activity without reliance on permanent subsidization of energy; and
8. Protecting New Hampshire's interests in regional energy matters.[28]

Natural gas continues to be featured prominently in the Update in the context of an input fuel for electric generation and as a heating fuel. The Update theme of supply diversity and elimination of economic subsidization of competing technologies favors gas expansion in the State. With respect to natural gas in in the home heating segment, the 10-Year State Energy Strategy notes that New Hampshire ranks second in the nation in oil heating per capita, with 42% of New Hampshire citizens using oil as their primary source of heat in 2019.[29] Approximately 6% of New Hampshire households rely on wood as a primary source of home heating.[30] Roughly 20% of customers classified under "Electric Heat" use heat pumps, which is approximately 2% of the statewide total. Correspondingly, New Hampshire has a much lower share of households using natural gas and electricity for heating than the national average.

As is the case in Maine, New Hampshire is committed to advancing energy efficiency initiatives in the State. On February 24, 2022, HB 549 was signed into law. Among other things, HB 549 amended RSA chapters 374 and 374-F relative to energy efficiency program funding, cost effectiveness, and future energy efficiency filing. Pursuant to RSA 374-F:3, IV, as amended by HB 549, Northern and the other New Hampshire electric and natural gas utilities submitted an EE plan for program offerings available from May 1, 2022 through January 1, 2024 (the "2022-2023 Plan"). The Commission approved the 2022-2023 Plan, finding it to be consistent with the directives of HB 549.[31] Northern is currently administering energy efficiency programs in New Hampshire consistent with the 2022-2023 Plan. The Company is currently working with the other New Hampshire electric and natural gas utilities, as well as other interested stakeholders, to develop proposed program offerings for the next triennial period; the next three-year plan will be filed on or before July 1, 2023.[32]. New Hampshire energy efficiency is discussed further below.

E. Clean Air Act of 1990

1. Overview of Clean Air Act

Northern provides an overview of the Clean Air Act and relevant air quality measures to provide context for its assessment regarding the integration of the IRP and its impact on New Hampshire's compliance with the Act and other environmental laws, as required by RSA 378:38.V.

[28] New Hampshire 10-Year State Energy Strategy at 7 (July 2022).
[29] Id. at 58.
[30] Id.
[31] DE 20-092, Order No. 26,621 ("Order on the 2022-2023 New Hampshire Statewide Energy Efficiency Plan") at 1, 36-37 (April 29, 2022).
[32] RSA 374-F:3, VI-a(d)(3).

The Clean Air Act ("CAA") is a federal law that defines the United States Environmental Protection Agency's ("EPA") responsibilities for protecting and improving the nation's air quality and the stratospheric ozone layer. The last major change in the law, the Clean Air Act Amendments of 1990, was enacted by Congress in 1990.[33] The Act was first established in 1963 and revised in 1970, the same year that the EPA was established and given the primary role of carrying out the law. In 1990 Congress expanded and amended the CAA, giving EPA more authority to reduce air pollution. The EPA sets limits on certain air pollutants, including setting limits on how much of these pollutants can be in the air anywhere in the United States.[34]

The CAA requires EPA to set ambient outdoor air standards for specific pollutants. EPA has set National Ambient Air Quality Standards (NAAQS) for the six criteria air pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO2), ozone, particulate matter (PM2.5 and PM10), and sulfur dioxide (SO2).[35]

The Act is intended to improve health and the environment by reducing air pollution in the United States. The sectors listed by EPA as a part of the Act are the following: Agriculture - Crop Production and Animal Products, Automotive Sectors, Construction, Electric Power Generation, Transmission and Distribution, Oil and Gas Extraction, Transportation and Warehousing, and others.[36] While there are several industries that are directly affected by the Clean Air Act, there is no direct application of the Clean Air Act to gas utilities.

The federal government establishes minimum pipeline safety standards under the U.S. CFR, Title 49 "Transportation", Parts 190 - 199. The Office of Pipeline Safety (OPS), within the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), has overall regulatory responsibility for hazardous liquid and gas pipelines under its jurisdiction in the United States.

Specifically, the CFRs include three parts relevant to the transport of natural gas and LNG facilities:

- Part 191: Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, And Safety-Related Condition Reports;
- Part 192: Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards; and
- Part 193: Liquefied Natural Gas ("LNG") Facilities: Federal Safety Standards.

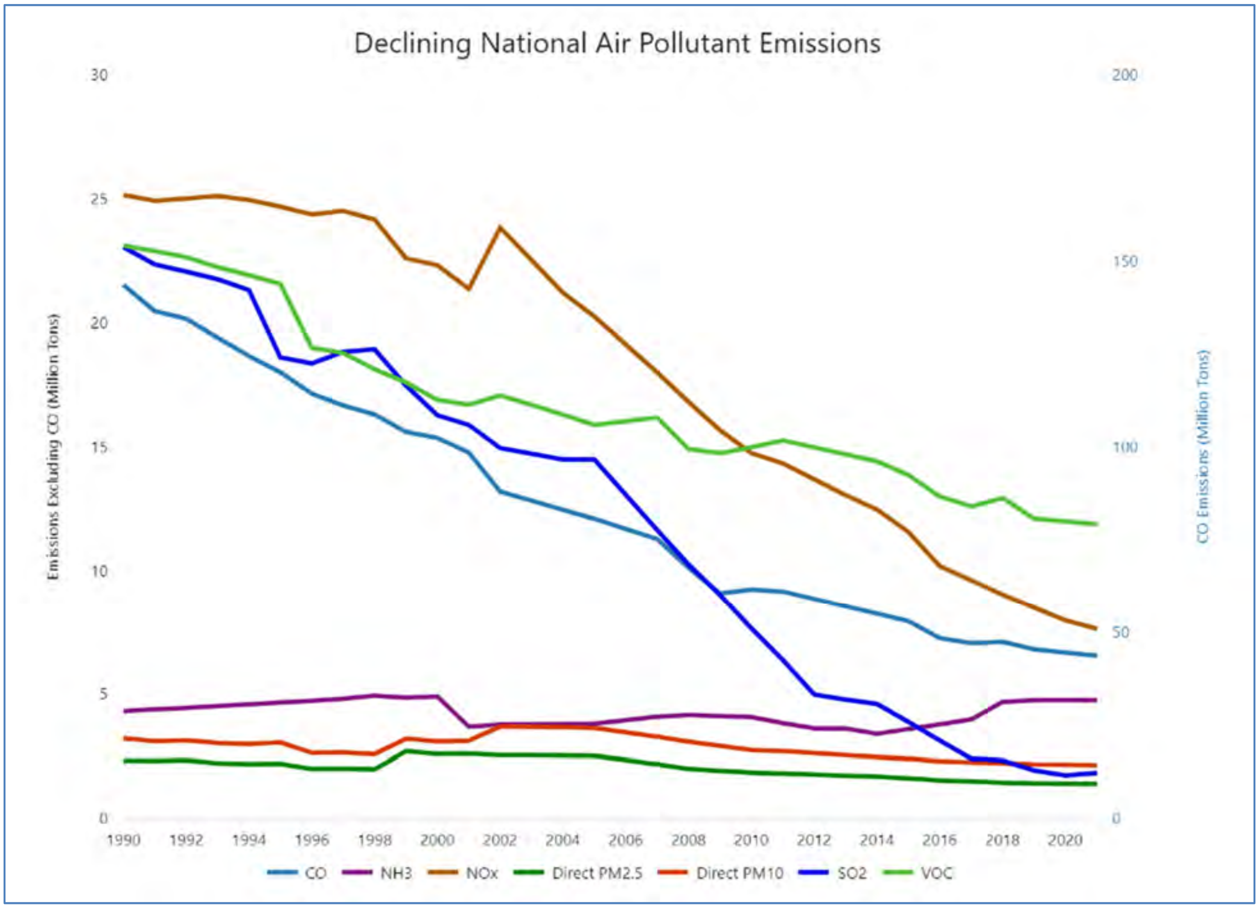
These CFRs dictate pipeline and LNG safety standards and do not address air emissions, air quality, or contain any reference to the CAA. Importantly, however, although the primary objective of these regulations is safety, the resulting investment in natural gas systems to enhance integrity has also

[33] US EPA Clean Air Act Text, at https://www.epa.gov/clean-air-act-overview/clean-air-act-text. The Clean Air Act was incorporated into the United States Code as Title 42, Chapter 85.
[34] US EPA Regulatory Information by Topic: Air, at https://www.epa.gov/regulatory-information-topic/regulatory-information-topic-air.
[35] State of New Hampshire Air Quality–2017: Executive Edition, R-ARD-17-01-E, March 2018, Prepared by the New Hampshire Department of Environmental Services, page 3.
[36] Others listed include: Dry Cleaning, Educational Services, Forestry & Logging, Healthcare & Social Assistance, Manufacturing, Mining, Public Administration & Government, Water and Sewage Utilities Sector.

significantly reduced fugitive emissions. At the end of this Section III.E., we list progress Northern has made in replacing leak prone pipe on its distribution system, which reduces air quality impacts.

In terms of improvements in air emissions over time, in the United States from 1990 to 2017 emissions of air toxics declined by 74%.[37] The levels of emissions of key air pollutants continue to decline from 1990 levels, as shown in Figure III-1.

Figure III-1: Declining National Air Pollutant Emissions[38]



To provide context for the emissions levels shown in Figure III-1 relative to current national emissions standards, or NAAQS, for criteria pollutants, Figure III-2 provides national concentration averages of air pollutants, which have similarly dropped significantly since 1990. As EPA mentions, despite increases in air concentrations of pollutants associated with fires, namely carbon monoxide and particle pollution, national average air quality concentrations remain below the current national standards.

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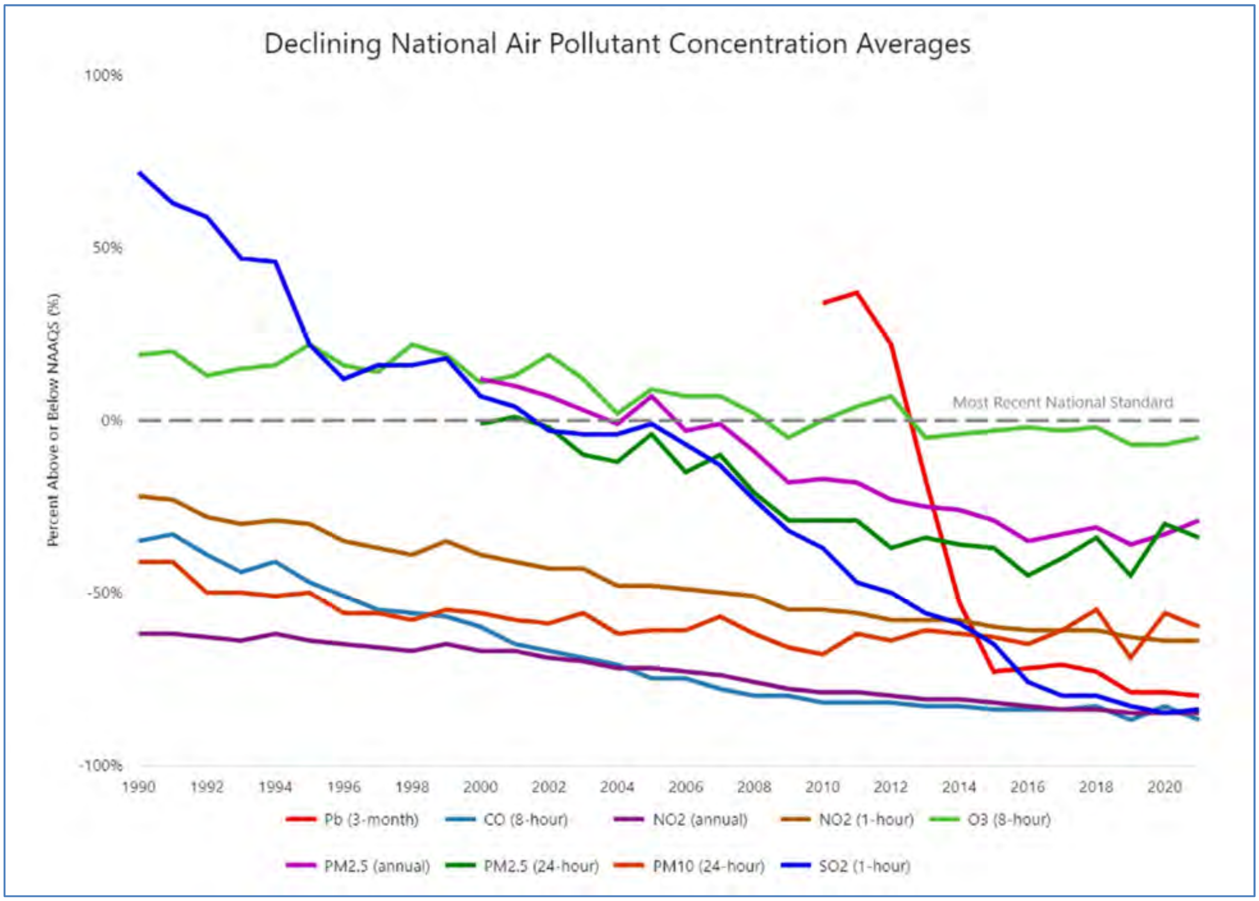
37 Emission Trends, at https://gispub.epa.gov/air/trendsreport/2022/#introduction.

38 Ibid. Decreases from 1990 levels are as follows: Carbon Monoxide (CO), 70%, Ammonia (NH3), up 10%, Nitrogen Oxides (NOx), 70%, Direct Particulate Matter 2.5 microns (PM2.5), 40%, Direct Particulate Matter 10 microns (PM10), 33%, Sulfur Dioxide (SO2), 92%, Volatile Organic Compounds (VOC), 49%.

Figure III-3: Declining National Air Pollutant Concentration Averages[39]



To provide context on where and what types of emissions come from different sources, Figure III-3 shows pollutants emitted by source categories. The sources categories are defined as follows: "Stationary Fuel Combustion" sources include electric utilities and industrial boilers, "Industrial and Other Processes" include metal smelters, petroleum refineries, cement kilns and dry cleaners, "Highway Vehicles" is straightforward, and "Non-Road Mobile" sources include recreational and construction equipment, marine vessels, aircraft and locomotives.

The nationwide shift to natural gas for electric generation has significantly helped to reduce greenhouse gas emissions (GHG). Since the beginning of the shale gas revolution in the 2008-2009 timeframe, gas-fired electric generation has supplanted coal and gas as the primary fuel of choice. According to the EPA, total CO2 emissions from fossil fuel combustion equaled 4,651 MMTe in 2021, which is 19 percent below 2005 levels.[40]

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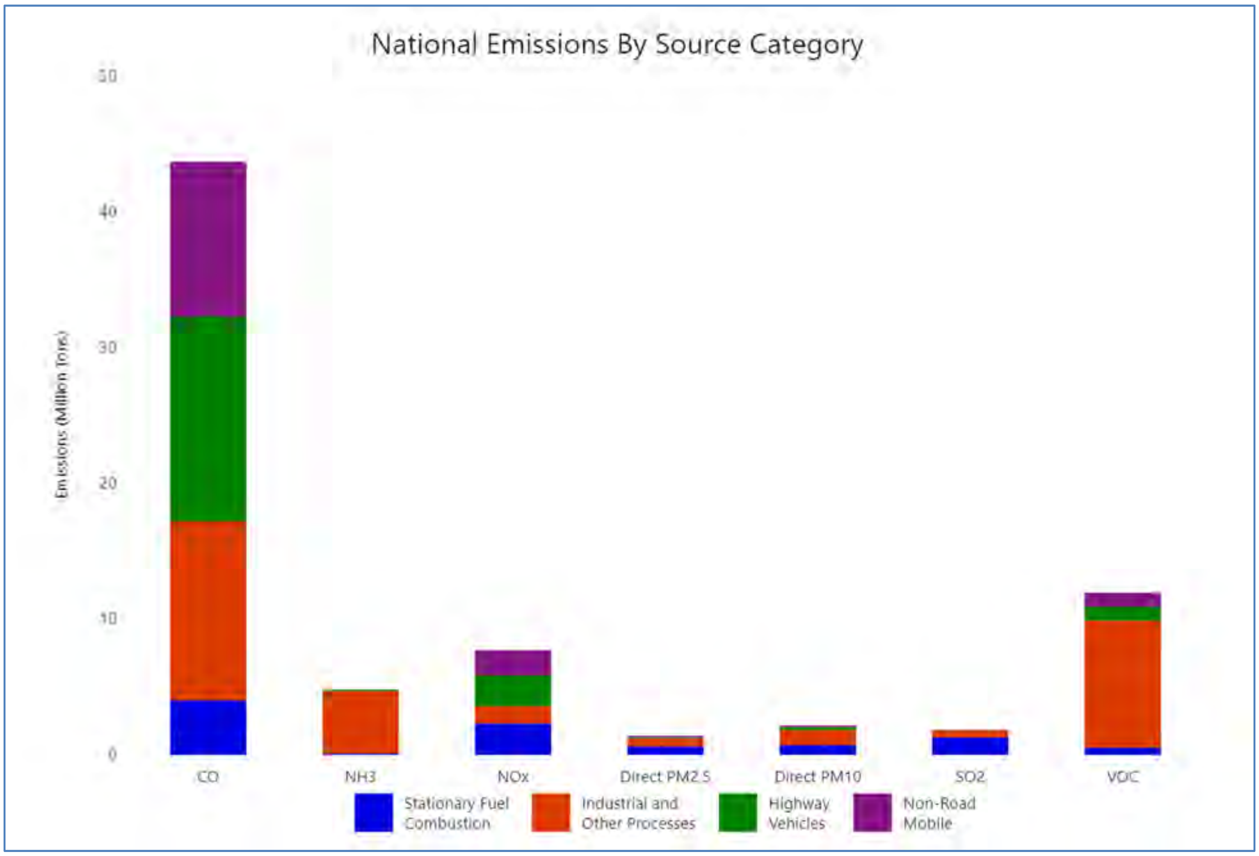
[39] Emission Trends, at https://gispub.epa.gov/air/trendsreport/2022/#introduction.

[40] EPA (2023) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021. U.S. Environmental Protection Agency, EPA 430-D-23-001. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021, Table 3-5.

Locally, the CAA has enabled New Hampshire to come into compliance with the National Ambient Air Quality Standards for each NAAQS, and to maintain that compliance while improving visibility throughout the state and reducing acid, nitrogen and mercury deposition and providing a cleaner and healthier environment.[41] The EPA also lists Maine as maintaining compliance with the Standards. Both Maine and New Hampshire are listed on EPA's website as having improved visibility at national parks and scenic areas.[42]

New Hampshire Governor Christopher Sununu stated in the 2017 State of New Hampshire Air Quality report that the state "ha[s] enacted reasonable incentives for low pollution renewable power and cost-effective market-based solutions to address greenhouse gases from the energy sector."[43]

Figure III-3: National Emissions by Source Category[44]



41 State of New Hampshire 2020 Air Quality Update, at https://www.des.nh.gov/sites/g/files/ehbemt341/files/documents/r-ard-21-05.pdf, Page 18.

42 https://gispub.epa.gov/air/trendsreport/2018/#scenic_areas

43 State of New Hampshire Air Quality–2017: Executive Edition, R-ARD-17-01-E, March 2018, Prepared by the New Hampshire Department of Environmental Services, Page ii.

44 Emission Sources, at https://gispub.epa.gov/air/trendsreport/2022/#sources.

2. Implications of Clean Air Act for Northern

Despite no immediately direct connection between the CAA and gas distribution companies, in the spirit of the Act, Northern has focused on (i) participating in energy efficiency programs to help customers reduce their overall energy consumption; (ii) expanding its system to convert customers from oil to gas; and (iii) improving its distribution system by replacing leak prone pipe to reduce the risk of fugitive gas emissions. From a supply perspective, although Northern's gas supply portfolio is not adequate to meet its Planning Load obligations without purchasing short term supply, meaning that Northern cannot simply turnback existing supply resources, Northern is working to better understand the environmental attributes of the pipelines and storage facilities it relies upon to serve customers. Northern is also exploring non-pipeline supply options, including renewable natural gas, which could be carbon neutral or net negative, as well as certified gas, which is geologic gas demonstrated to have been produced with very low emissions.

Energy Efficiency activity is described in several sections of the IRP, including in Part B of Section III, which describes the environment in which customer funded Energy Efficiency programs are developed and implemented for Northern's customers, as well as in Section V, which shows how energy efficiency savings from those are incorporated into the Demand Forecast, Section VII, which describes the current Energy Efficiency programs and Section IX, which presents Energy Efficiency generally as a potential Incremental Resource, and Section X, which reviews Resource Impacts of Energy Efficiency.

The share of households using natural gas, fuel oil, electricity, propane, and other fuels to heat homes varies from state to state. As shown in Table III-1, the share of homes that heat with natural gas in Maine and New Hampshire is 8.1% and 22.3%, respectively, both of which lag well behind the average natural gas penetration for home heating of 46.5% across the United States. Fuel oil is the most common home heating fuel of households in both Maine and New Hampshire.

Table III-1: Home Heating Source by State, 2021[45]

Fuel	Maine	New Hampshire	U.S. Average
Natural Gas	8.1%	22.3%	46.5%
Fuel Oil	58.1%	39.9%	4.1%
Electricity	10.3%	10.7%	41.0%
Propane	13.2%	18.7%	5.0%
Other/None	10.3%	8.5%	3.5%

[45] https://www.eia.gov/state/data.php?sid=ME#ConsumptionExpenditures, https://www.eia.gov/state/data.php?sid=NH#ConsumptionExpenditures.

The production, delivery and consumption of natural gas produces, like other energy sources, greenhouse gases (GHGs) including Carbon dioxide (CO_2), Methane (CH4), and Nitrogen dioxide (NOx). GHGs are emitted through fuel combustion and can cause harm to humans and the environment. Representative levels of CO_2, CH4, and NOx for the combustion of major sources of heating fuel used in Maine and New Hampshire are listed in Table III-2.

Table III-2: GHG Emissions by Fuel Type[46]

Fuel	CO2 (kg/mmBtu)	CH4 (g/mmBtu)	N2O (g/mmBtu)
Natural Gas	53.06	1.0	0.1
Propane	62.87	3.0	0.6
#2 Fuel Oil	73.96	3.0	0.6

As can be seen in Table III-2, natural gas results in the lowest emissions from combustion across all GHGs when compared to other fuel types. It is also important to note that while CH4 and NOx have relatively low emissions when compared with CO2, they have much higher global warming potentials (GWP), meaning they are much more potent than CO2. Typically, greenhouse gas emissions are reported in units of carbon dioxide equivalent (CO2e). Gases are converted to CO2e by multiplying by their global warming potential (GWP), where the GWP of CO2 equals 1. The latest 100-year GWP of CH4 is 34 and the GWP of N2O is 298. See Table III-3.

Table III-3: Global Warming Potential (GWP) of GHG Emissions[47]

GHG	Lifetime (years)	100 Year GWP w/o cc fb AR5	100 Year GWP with cc fb AR5	20 Year GWP w/o cc fb AR5	20 Year GWP with cc fb, AR5
CO2	n/a	1	1	1	1
CH4	12.4	28	34	84	86
N2O	121.0	265	298	264	268

cc fb = climatecarbon feedback

In terms of converting customers from oil to gas, recent history and the IRP forecast show that Northern adds approximately new 1,200 customers annually, approximately 1,050 of which are residential. The majority of existing homes and businesses Northern acquires are customers who switch from fuel oil. On an MMBtu equivalent basis, based on the data in Table III-2, substituting natural gas for

46 EPA, Emission Factors for Greenhouse Gas Inventories, April 2022. Available at: https://www.epa.gov/system/files/documents/2022-04/ghg_emission_factors_hub.pdf

47 Myhre, G., et.al., 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Table 8.7, p. 714.

fuel oil reduces CO_2 emissions by 28 percent (53.06/73.96-1), and reduces CH4 and N2O emissions by even more.

Natural gas, or methane (CH_4), is a GHG in its natural state. Gas utilities across the nation, including Northern, have accelerated their leak-prone pipeline replacement programs in an effort to increase public safety and reduce the risk of methane fugitive emissions. According to the EPA, methane emissions from Natural Gas Systems have decreased by 14.2 percent since 1990, with decreases in distribution emissions largely due to a reduction in emissions from pipelines and distribution station leaks.[48]

The EPA assesses Natural Gas Systems in 6 separate segments, as listed in Table III-4 below. Note that emissions from natural gas distribution systems account for only 8 percent of methane emissions from natural gas systems, as shown in Table III-4.

Table III-4: CH4 Emissions from Natural Gas Systems (MMT CO2 Eq.)[49]

Segment	1990	2005	2017	2018	2019	2020	2021	2021%
Exploration	3.3	10	1.4	2.6	2.1	0.2	0.2	0%
Production	64.7	97.9	103.5	107.0	104.7	97.3	94.0	52%
Onshore Production	39.3	69	59.9	62.9	59.4	53.8	50.0	28%
Gathering and Boosting	20.7	26.8	42.9	43.3	44.6	42.6	43.4	24%
Offshore Production	4.8	2	0.7	0.8	0.7	0.9	0.7	0%
Processing	23.9	13	12.9	13.5	14.2	13.9	14.3	8%
Transmission and Storage	64.1	44.3	41.0	43.2	44.3	45.5	44.6	25%
Distribution	50.9	28.5	15.7	15.6	15.5	15.5	15.3	8%
Post-Meter	8.1	9.6	11.9	12.5	12.8	13.0	13.0	7%
Total	**215.1**	**203.4**	**186.4**	**194.4**	**193.6**	**185.4**	**181.4**	**100%**

Both CO_2 and methane emissions have been reduced through the replacement of leak-prone pipes with state of the art materials, including high-density polyethylene (plastic). Nationwide, nearly 90 percent of the decline in fugitive emissions from distribution systems since 1990 is attributed to pipeline replacements.[50] Total leak-prone pipe (miles of distribution main) in the U.S. has decreased from 133,768 miles in 1990 to 56,771 miles in 2017.

In terms of distribution system improvements, Northern has been aggressively replacing leak-prone pipes, including bare steel, coated non-cathodically-protected steel, cast iron and wrought iron. The leak-prone pipes made from these materials are often referred to as "CIBS" (cast iron bare steel). CIBS pipe is identified as leak-prone for a variety of reasons, including its susceptibility to corrosion and

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48 EPA (2023) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021. U.S. Environmental Protection Agency, EPA 430-D-23-001. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.

49 Ibid, at 3-82.

50 https://www.aga.org/globalassets/2019-increase-in-safety-leads-to-a-decrease-in-emissions-v.3.pdf

graphitization. In response to multiple high-profile incidents, PHMSA issued a "Call to Action" to accelerate replacement of CIBS across the country.[51]

From 2010-2022, Northern retired approximately 66.78 miles of leak prone (CIBS) distribution pipeline in Maine and 42.25 miles of leak prone distribution pipeline in New Hampshire. At of the end of 2022, Northern reports approximately 14.09 miles of leak prone pipe remaining in Maine and .14 miles in New Hampshire. As shown in Table III-5, since 2010, Northern has replaced 99.67% of CIBS mains pipeline in the New Hampshire Division, and 82.58% of CIBS mains in the Maine Division. Taken together, Northern has replaced 109.03 miles of leak prone pipe, or 88% relative to 2010 level CIBS mains, representing a (23.7%) annual reduction. By comparison, the U.S. as a whole has only replaced approximately 46% of its 2010 level CIBS mains, representing a (7.4%) annual reduction. This comparison is shown in Table III-5.

Table III-5: CIBS Pipe Replacement: Northern vs. The U.S.[52]

	Miles of CIBS Mains		Percent of 2010 miles replaced	Annual Percentage Change
	2010	2022		
Northern ME	80.87	14.09	82.58%	-19.6%
Northern NH	42.39	0.14	99.67%	-
Northern Total	123.3	14.23	88%	-23.7%
U.S.	100,248	54,074	46%	-7.4%

A. Regional Market Overview

This Section III.F discusses New England natural gas market conditions to provide context for the Company's resource planning process and activities. The region is experiencing a period of expected long-term volatility and periodic supply constraints brought about by market (supply/demand) dynamics and policy effects described below. Given this volatility, the Company seeks additional supply resources and highly values resource flexibility to ensure its ability to continue providing reliable and reasonably priced supply.

There is unprecedented uncertainty with respect to future natural gas demand and supply, natural gas pricing implications, including the role and impact of climate-related policies in New England, which will impact the Company's long-term resource planning and strategy. Since Northern's 2019 IRP, significant challenges associated with the natural gas market environment in the New England region, particularly during the winter period, have continued to impact the Company's resource plans. Specifically, overall demand for natural gas in New England has continued to be strong, however, the various natural gas supply issues previously discussed in the Regional Market Overview of the 2019 IRP

51 https://opsweb.phmsa.dot.gov/pipeline_replacement/action.asp

52 Source: Unitil CIBS Main Data Source PHMSA 7100 Annual Report.

have continued to be a major challenge for market participants. The regional natural gas market demand and supply conditions have resulted in extremely volatile New England natural gas prices during the winter period, with natural gas demand and associated market area prices oscillating between relatively low demand with low gas prices and high demand with extremely high gas prices. In addition, the regional trends in energy and environmental policy to address climate change have continued to impact the availability of new infrastructure.

The remainder of this section is organized as follows:

Part 1, Natural Gas Demand Trends, reviews natural gas demand growth over the past 20 years;

Part 2, Natural Gas Supply Issues, reviews U.S. and Canadian production and reserves in supply basins that are deliverable to New England, constraints on the existing pipeline system and concerns over the ongoing viability of the region's imported LNG facilities, upon which the New England region is heavily dependent;

Part 3, Implications for Regional Natural Gas Prices, reviews the regional natural gas prices and the impact of energy market conditions on New England natural gas prices and basis values;

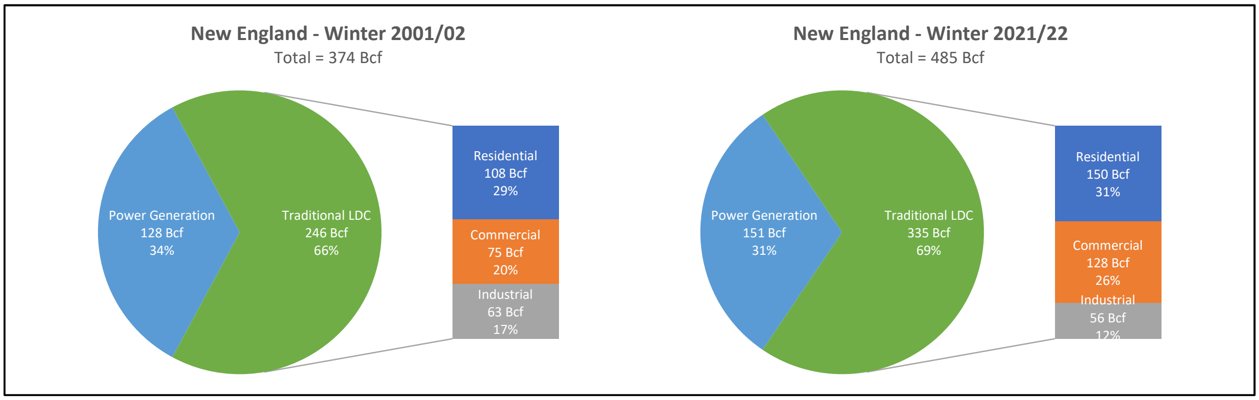
Part 4, Energy and Environmental Policy, discusses uncertainty stemming from energy and climate policy, which highlights the fact that Northern needs to maintain flexibility within its resource portfolio notwithstanding its need to also build and maintain a portfolio that meets its Planning Load.

1. Natural Gas Demand Trends

In the New England region, natural gas is the leading fuel for electric power generation and space heating, with natural gas consumption peaking during the winter period.[53] As depicted in Figure III-4 (below), both the traditional LDC and power generation sectors have experienced increases in winter natural gas consumption over the past 20 years. Specifically, winter natural gas consumption by the traditional LDC sector in the region increased from approximately 246 Bcf in 2001/02 to approximately 335 Bcf in 2021/22, or by approximately 36 percent. Over that same time period, winter natural gas consumption by the power generation sector in New England increased from approximately 128 Bcf to approximately 151 Bcf, or by approximately 18 percent. Thus, in total, natural gas demand in New England increased from approximately 374 Bcf in winter 2001/02 to 485 Bcf in winter 2021/22, or by approximately 30 percent, with demand from gas LDCs growing at twice the rate as demand of power generation. Within the LDC sector, it is noteworthy that industrial customer demand dropped, with a 20-year compound annual growth rate ("CAGR") of -0.6% while residential demand grew at a 20-year CAGR of 1.7% and commercial demand led the way with a 20-year CAGR of 2.7%.

[53] Throughout this section, the winter period refers to the five months from November to March and the summer period refers to the seven months from April to October.

Figure III-4: Winter Natural Gas Consumption in New England[54]

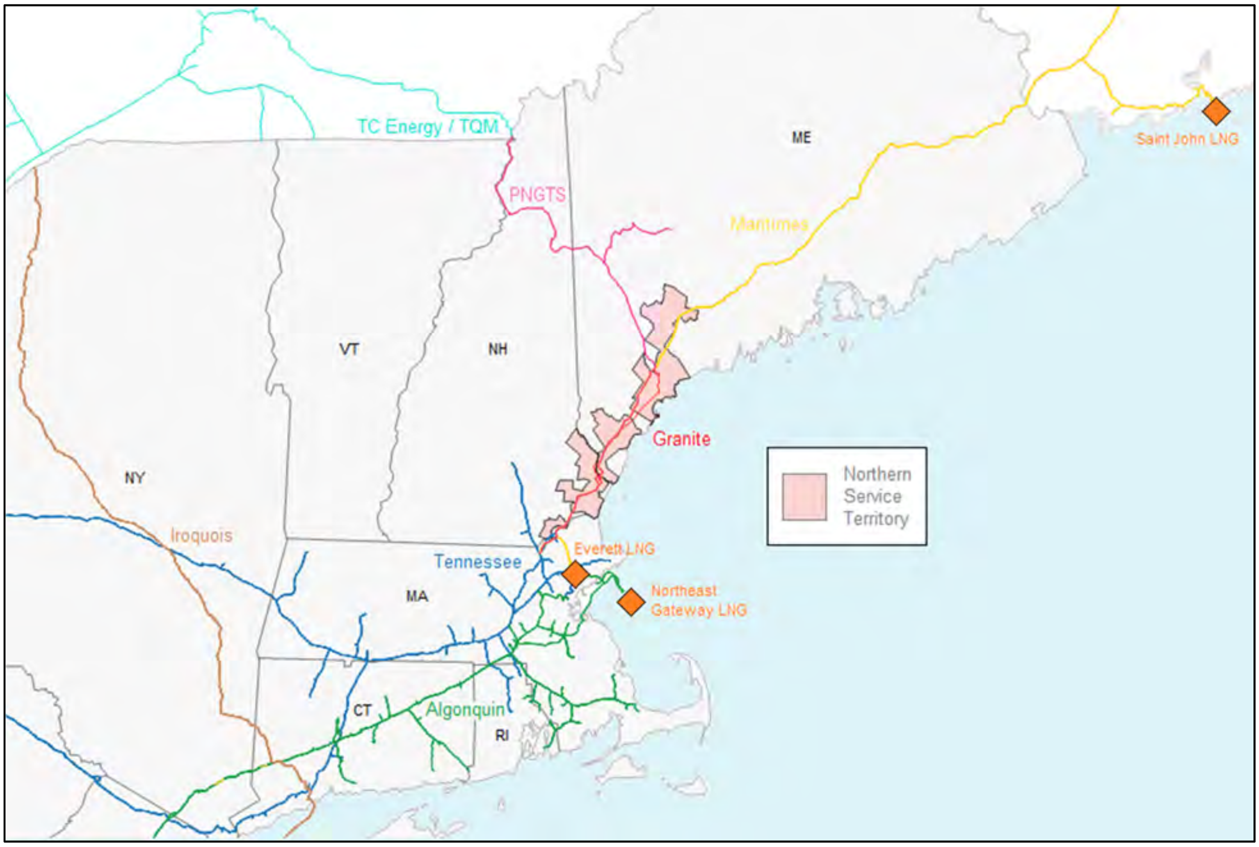


2. Natural Gas Supply Issues

Since New England is not a natural gas-producing region and has no underground natural gas storage, the New England region relies on natural gas supplies that are primarily delivered to the region via interstate pipelines from the U.S. production areas (i.e., the Appalachian and Gulf Coast regions) and Canada, as well as imported LNG. The five major interstate pipelines serving the New England region are Algonquin Gas Transmission ("Algonquin"), Iroquois Gas Transmission ("Iroquois"), Maritimes and Northeast Pipeline ("Maritimes"), Portland Natural Gas Transmission System ("PNGTS"), and Tennessee Gas Pipeline ("Tennessee"). As shown in Figure III-5 (below), the New England region is essentially at the "end of the line" with respect to interstate pipeline infrastructure. Also illustrated in Figure III-5 (below) is the Company's service territory in Maine and New Hampshire, which is served by the Maritimes, PNGTS, and Tennessee pipelines, each of which deliver to Northern directly or via Granite State Gas Transmission ("Granite") and provide the Company with access to the various upstream natural gas supply sources.

[54] Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, February 28, 2023. Represents combined data for Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, and Vermont with estimated data for certain months in 2021/22.

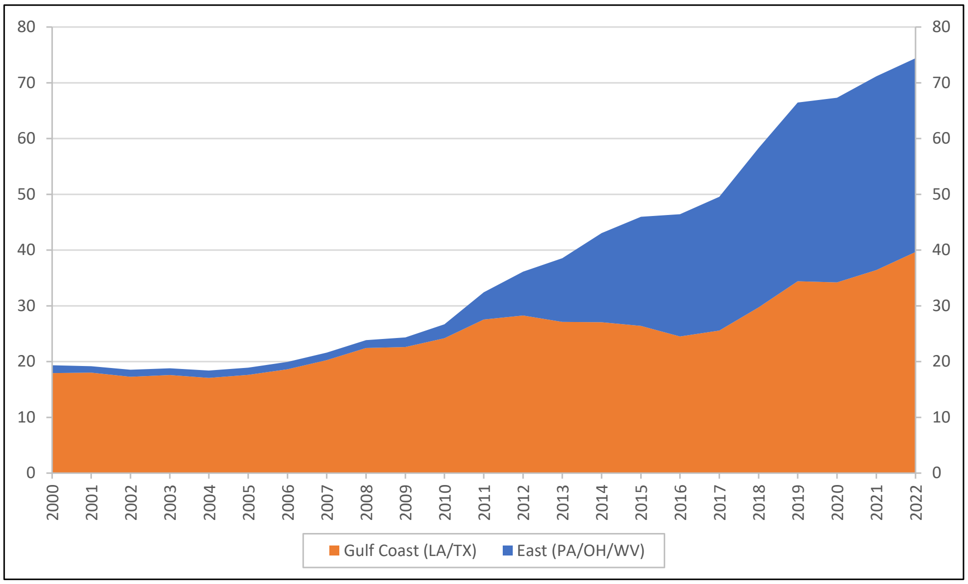
Figure III-5: Northern Service Territory and Regional Natural Gas Infrastructure



a) U.S and Canadian Gas Production

The primary natural gas supply basins in North America are the U.S. Appalachian (i.e., Marcellus and Utica), U.S. Gulf Coast, and Western Canadian Sedimentary Basin ("WCSB"). Figure III-6 (below) illustrates the significant increase in U.S. natural gas production from the East (i.e., Appalachian region) since 2010, as well as the historical natural gas production from the U.S. Gulf Coast region.

Figure III-6: U.S. Gulf Coast and East Natural Gas Marketed Production (Bcf/day)[55]

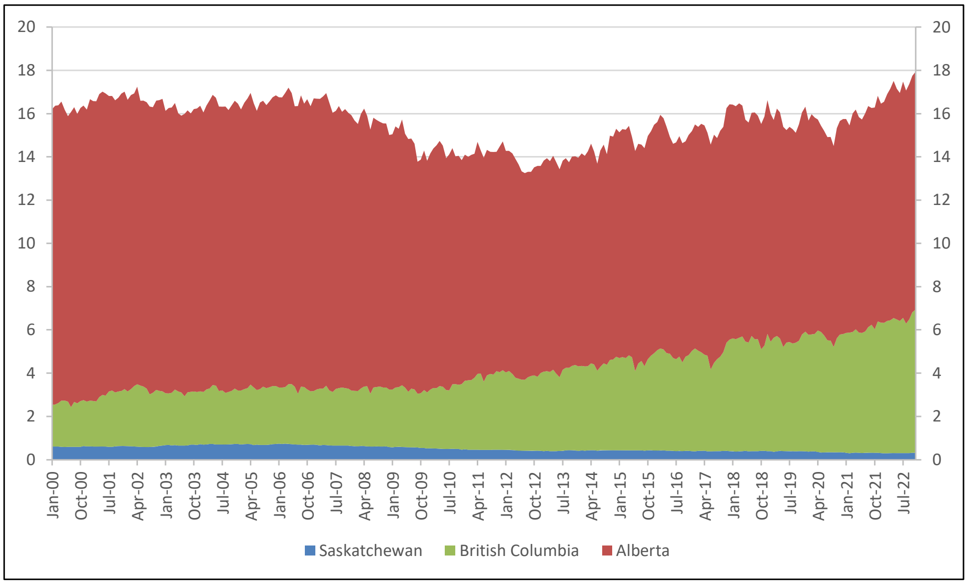


Based on the most recent estimates published by the Potential Gas Committee ("PGC"), there is over 1,300 Tcf of potentially recoverable gas resources in the Atlantic region, which encompasses the Marcellus and Utica supply basins, and over 500 Tcf in the Gulf Coast.[56] In addition, the U.S. EIA provides estimates of proved reserves that are demonstrated with reasonable certainty (i.e., 90 percent probability or greater) to be recoverable under existing economic and operation conditions, which are supplemental to the PGC estimates. According to the most recent estimate from the U.S. EIA, the level of proved reserves in the major U.S. shale plays include the Appalachian (i.e., Marcellus and Utica shale basins) at approximately 177 Tcf and Gulf Coast (i.e., Haynesville/Bossier and Eagle Ford) at approximately 86 Tcf.[57]

With respect to Canadian gas supply, the WCSB natural gas production basin is situated in the Alberta, British Columbia, and Saskatchewan provinces. As illustrated in Figure III-7 (below), total WCSB natural gas production has increased from 2009-2014 levels (i.e., approximately 13 Bcf/day to 14 Bcf/day) to a record high of nearly 18 Bcf/day in November 2022.

[55] Source: U.S. Energy Information Administration, Natural Gas Marketed Production, February 28, 2023.
[56] Source: Potential Gas Committee, "Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee (December 31, 2020)," October 19, 2021.
[57] Source: U.S. Energy Information Administration, Proved Reserves of Crude Oil and Natural Gas in the United States, Year-End 2021, December 30, 2022.

Figure III-7: WCSB Natural Gas Marketed Production (Bcf/day)[58]

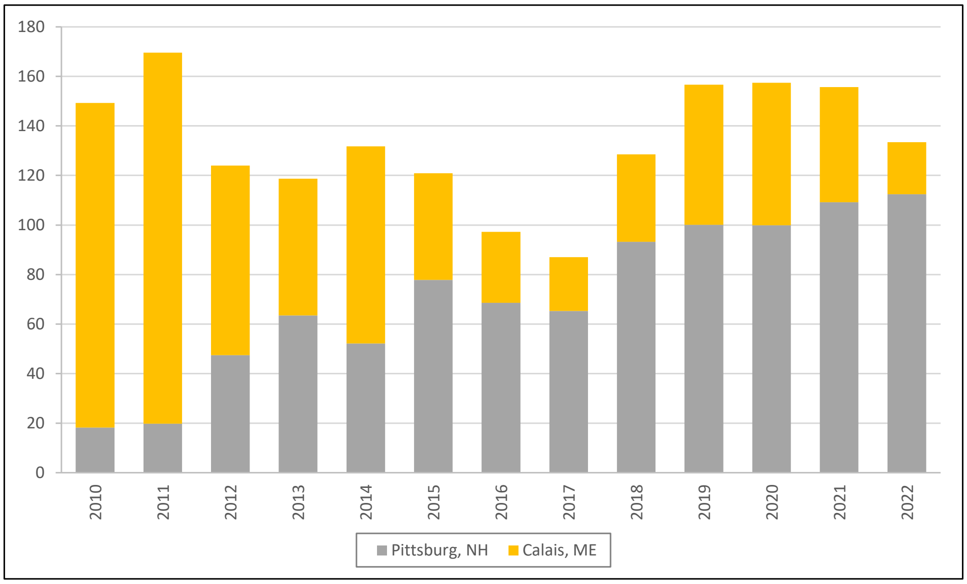


As noted by the Canada Energy Regulator, the most recent estimate of ultimate natural gas potential in the WCSB is well over 1,000 Tcf.[59] While estimates of potential gas resources, in general, may be considered speculative and dependent on natural gas prices and extraction technologies, the substantial volume of natural gas potential in the WSCB demonstrates the considerable abundance of gas supply from the basin.

As shown in Figure III-8 (below), while natural gas deliveries from Canada to the New England region via Maritimes (i.e., imports at Calais, ME) have decreased from their 2010-2011 levels, natural gas deliveries to the region via PNGTS (i.e., imports at Pittsburg, NH) have increased significantly. The increase in the level of natural gas imports from Canada to the New England region via PNGTS has been supported by the successful development of pipeline expansion projects on Enbridge (Union Gas System) and TC Energy from the Dawn Hub[60] (in conjunction with several pipeline expansions on PNGTS). As illustrated in Figure III-8 (below), the level of natural gas imports from Canada to the interconnection with PNGTS at Pittsburg, NH has increased by over six-fold, from 18 Bcf in 2010 to approximately 112 Bcf in 2021.

[58] Source: Canada Energy Regulator, Marketable Natural Gas Production in Canada, February 22, 2023.
[59] Source: Canada Energy Regulator, "Published Estimates for Ultimately Recoverable Natural Gas in the WCSB," July 5, 2022.
[60] Enbridge's Dawn Hub is one of the largest integrated natural gas storage facilities in North America. As discussed in Northern's 2019 IRP, natural gas supply at the Dawn Hub, which has access to Appalachian (i.e., Marcellus and Utica) and WCSB natural gas production, has continued to increase and diversify.

Figure III-8: Natural Gas Import Volumes on PNGTS and Maritimes (Bcf)[61]



b) Regional Pipeline Capacity Constraints

As illustrated in Figure III-5 (above), there are a limited number of interstate pipelines serving the New England region. In addition, the existing interstate pipeline infrastructure into the region is fully subscribed. LDCs have contracted for the majority of the pipeline capacity via long-term contractual arrangements for firm pipeline transportation service to meet their customers' natural gas demand requirements. In contrast, as highlighted by the FERC in its most recent Winter Energy Market and Reliability Assessment, "many natural gas-fired generators in the region historically have not contracted for long-term firm pipeline capacity;" thus, power generators and other customers without firm pipeline service typically rely on remaining available capacity on the pipelines.[62]

During the winter period when natural gas demand from the power generation sector coincides with demand for space heating from the LDCs' customers, the interstate pipelines into the New England region often experience capacity constraints as they reach their maximum capacity. These pipeline capacity constraints lead to less flexibility for shippers (including LDCs) on the interstate pipeline systems and places upward pressure on New England natural gas prices. For example, Tennessee has indicated restrictions have been in place for nearly all of the winter period over the past four split-years at key points on their pipeline system that transport supplies to the New England market area.[63] In addition, the length

[61] Source: U.S. Energy Information Administration, U.S. Natural Gas Imports by Point of Entry, February 28, 2023.
[62] Federal Energy Regulatory Commission, Winter Energy Market and Reliability Assessment, updated October 25, 2022, at 37-38.
[63] For example, Tennessee's Station 245 was restricted 100 percent of the days in the winters of 2018/19 to 2021/22 and 99 percent of the days in winter 2021/22. See, Kinder Morgan, 2022 NGA Pre-Winter Briefing Meeting, November 17, 2022, at 5.

(in days) and number of operational flow orders ("OFOs") affecting deliveries to the New England market area on Tennessee have generally increased.[64]

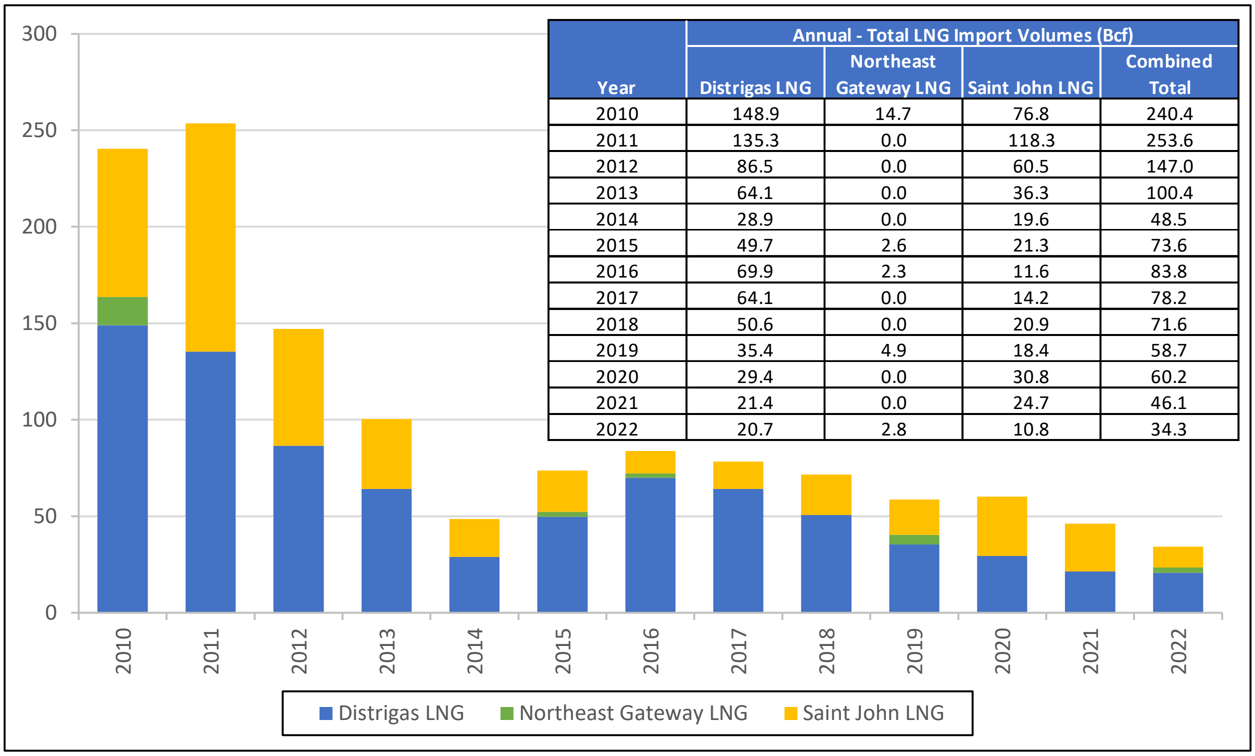
While natural gas demand in the region has increased, there have been limited expansion projects to increase pipeline capacity to serve the New England region, in general, and the Company, in particular. Only three pipeline projects, which provide incremental capacity into the New England region, have successfully been placed in-service since the Company's 2019 IRP.[65] These projects include the PNGTS Portland XPress, PNGTS Westbrook XPress, and Algonquin Atlantic Bridge projects; and, notably, the Company has contracted for firm pipeline service on all three projects. Over the planning period, there may be incremental capacity projects on PNGTS and Algonquin. Specifically, PNGTS has indicated that limited incremental capacity may be available on PNGTS; and Enbridge has indicated that brownfield expansions on the Algonquin Mainline are being considered.[66] There are currently no proposed pipeline expansion projects on Tennessee to serve the New England market area.

c) Reliance on Imported LNG for Peaking Supplies

During the peak winter period, the New England region relies on incremental supplies from the regional LNG import terminals to meet natural gas demand requirements. There are currently three active LNG import terminals that serve the New England and Atlantic Canada region; specifically, the Constellation LNG, LLC ("CLNG") Distrigas LNG facility in Everett, MA; Excelerate Energy's offshore Northeast Gateway LNG facility in Cape Ann, MA; and Repsol Energy North America's ("Repsol") Saint John LNG facility in Atlantic Canada (formerly, the Canaport LNG facility). As discussed in the Company's 2019 IRP, the LNG import volumes at the Distrigas LNG and Saint John LNG facilities have decreased significantly from their 2011 levels; and the LNG import volumes at the Northeast Gateway LNG facility have been limited. Figure III-9 (below) illustrates the combined annual LNG import volumes at the three active regional LNG import terminals, which ranged between approximately 30 Bcf and 60 Bcf over the most recent four years.

[64] See, Kinder Morgan, 2022 NGA Pre-Winter Briefing Meeting, November 17, 2022, at 6.
[65] As noted in Northern's 2019 IRP, the TGP 261 Upgrade project on the Tennessee system was limited to LDCs located in western Massachusetts and did not provide incremental supply to New England region.
[66] See, PNGTS, Shipper Meeting, October 12, 2022, at 35; and Enbridge, NGA Pre-Winter Meeting, November 17, 2022, at 8.

Figure III-9: Annual LNG Import Volumes (Bcf)[67]



Year	Annual - Total LNG Import Volumes (Bcf) Distrigas LNG	Northeast Gateway LNG	Saint John LNG	Combined Total
2010	148.9	14.7	76.8	240.4
2011	135.3	0.0	118.3	253.6
2012	86.5	0.0	60.5	147.0
2013	64.1	0.0	36.3	100.4
2014	28.9	0.0	19.6	48.5
2015	49.7	2.6	21.3	73.6
2016	69.9	2.3	11.6	83.8
2017	64.1	0.0	14.2	78.2
2018	50.6	0.0	20.9	71.6
2019	35.4	4.9	18.4	58.7
2020	29.4	0.0	30.8	60.2
2021	21.4	0.0	24.7	46.1
2022	20.7	2.8	10.8	34.3

Pricing and availability of imported LNG supplies for the New England region are heavily influenced by global LNG market dynamics. The New England region competes with international markets, such as Europe and Asia, for LNG import volumes to meet peak winter demand requirements and, thus, global LNG prices impact the winter natural gas prices in New England. Prior to the most recent winter, the Governors of the six New England states indicated in a July 27, 2022 letter to the U.S. Department of Energy Secretary Jennifer Granholm, "[t]he Russian invasion of Ukraine has exacerbated the pricing of nearly all energy commodities which is directly impacting energy consumers in our respective states" and emphasized that "[t]he increase in global liquified natural gas (LNG) pricing has been particularly acute." Notably, the global LNG supply chain issues led to record high global LNG prices and winter natural gas futures prices for New England in the summer of 2022.

Finally, due to certain commercial changes, there is uncertainty regarding the long-term availability of natural gas supplies from the Saint John and Distrigas LNG facilities for the New England region. Specifically, with respect to the Saint John LNG facility, Repsol continues to assess the feasibility of expanding the facility to add liquefaction capability to facilitate LNG exports, and recently received approval from the Canada Energy Regulator to extend the commencement date of LNG exports to May

[67] Source: U.S. Department of Energy, LNG Annual Reports for 2011-2021; U.S. Department of Energy, LNG Monthly Report for 2022, February 15, 2023; and Canada Energy Regulator, LNG Exports and Imports Detail, February 12, 2023.

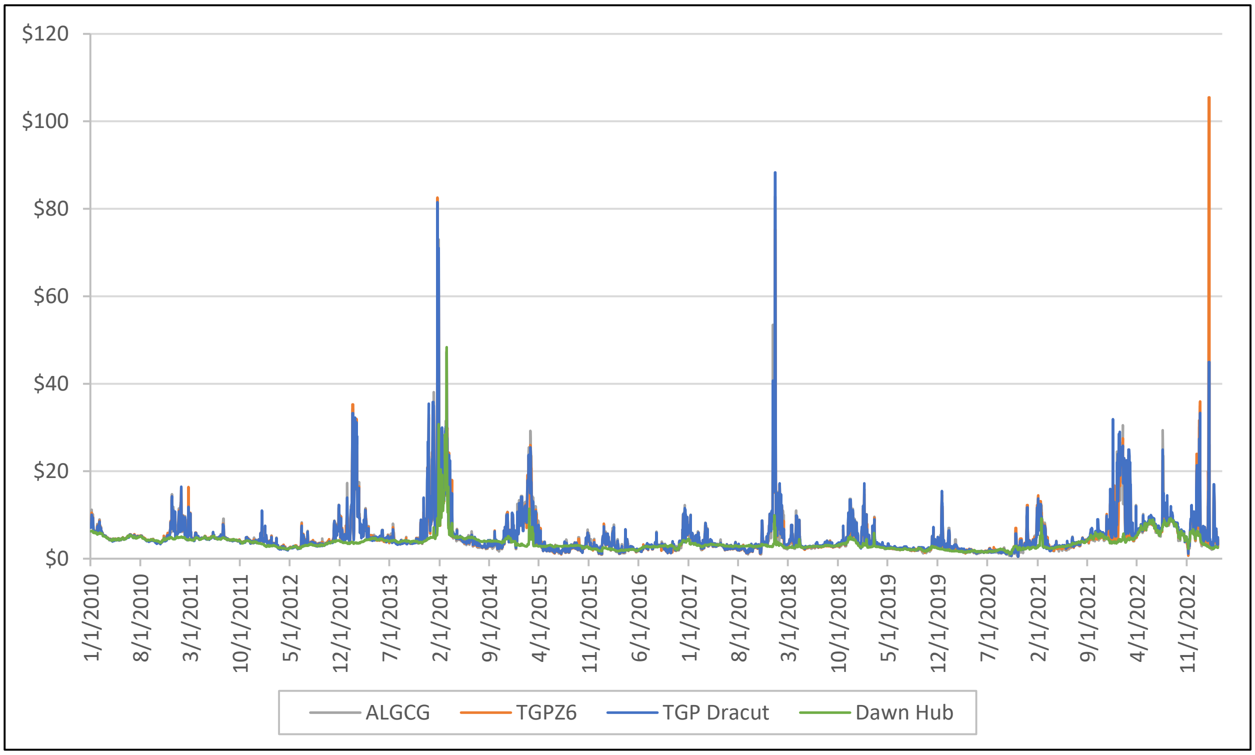
2032.[68] In addition, as discussed in the Company's 2019 IRP, there is significant uncertainty regarding the future of CLNG's Distrigas LNG facility, which currently provides delivered natural gas supplies (i.e., vapor and liquid) to certain LDCs in the region and is the sole source of natural gas supply for Constellation Mystic Power, LLC ("Mystic") generating units 8 and 9. While CLNG had received FERC approval for a cost-of-service agreement to support the continued operation of Mystic, the generating units are set to retire in mid-2024. Coinciding with the retirement of Mystic, CLNG's existing firm pipeline capacity contracts on Algonquin and Tennessee are set to expire in October 2024 and November 2024, respectively. CLNG has indicated that cost recovery associated with the continued operation and maintenance of the Distrigas LNG facility is uncertain after the retirement of Mystic, thus adding significant uncertainty with respect to the future availability and associated pricing of natural gas supplies from the Distrigas LNG facility. Notably, Northern typically purchases LNG for its Lewiston LNG vaporization plant from CLNG.[69]

3. Implications for Regional Natural Gas Prices

Natural gas prices in the New England market area, as represented by the Algonquin Citygate ("ALGCG"), Tennessee Zone 6 ("TGPZ6"), and TGP Dracut prices indices, have exhibited significant volatility at high price levels during the winter period relative to other supply regions, such as the Dawn Hub, as illustrated in Figure III-10 (below). As noted by the U.S. EIA, the key market drivers for the high winter natural gas prices in the New England region include: the weather-driven demand increases (for both space heating and electric power generation); the constraints on the region's interstate natural gas pipelines; and the limited incremental LNG supplies (all of which are discussed above).[70]

[68] See, Saint John LNG Development Company, Ltd., Application for a Variation of License GL-318 and GL-319 to the Canada Energy Regulator, September 14, 2022; and Canada Energy Regulator, Letter and Order AO-001-GL-318, January 24, 2023.
[69] Comments of Constellation Energy Generation, LLC. "New England Winter Gas-Electric Forum", Docket No. AD22-9-000, at 5.
[70] U.S. Energy Information Administration, "New England natural gas and electricity prices increase on supply constraints, high demand," February 3, 2022.

Figure III-10: Daily Spot Gas Prices ($/MMBtu)[71]



As illustrated in Figure III-10 (above), the New England market area price indices experience significant daily price spikes during the winter period. As shown in Table III-6 (below), the simple average daily price levels during the winter period of the New England market area indices have exceeded the simple average daily prices at the Dawn Hub by more than 50 percent in 9 of the last 13 winters. Focusing on the simple average daily prices over the most recent five winter periods, the simple average daily price at the Dawn Hub has been approximately $3/MMBtu below the simple average daily prices of the New England market area indices.

[71] Source: S&P Capital IQ.

Table III-6: Average Winter Spot Prices and Volatility[72]

Winter	Average Spot Prices ($/MMBtu)					Price Volatility				
(Nov-Mar)	Henry Hub	TGP Dracut	TGPZ6	ALGCG	Dawn Hub	Henry Hub	TGP Dracut	TGPZ6	ALGCG	Dawn Hub
2010/11	$ 4.10	$ 6.46	$ 6.52	$ 6.57	$ 4.59	32%	228%	249%	227%	23%
2011/12	$ 2.77	$ 3.85	$ 3.86	$ 3.86	$ 3.24	35%	180%	171%	171%	22%
2012/13	$ 3.47	$ 9.28	$ 9.31	$ 9.64	$ 3.83	24%	327%	298%	312%	20%
2013/14	$ 4.63	$ 15.76	$ 14.93	$ 15.09	$ 8.06	89%	452%	472%	473%	287%
2014/15	$ 3.26	$ 8.95	$ 8.88	$ 9.27	$ 3.87	43%	358%	370%	385%	143%
2015/16	$ 2.00	$ 3.07	$ 2.97	$ 3.02	$ 2.10	49%	267%	272%	321%	45%
2016/17	$ 3.04	$ 4.92	$ 4.82	$ 4.69	$ 3.27	45%	294%	231%	268%	48%
2017/18	$ 3.01	$ 8.71	$ 8.28	$ 8.13	$ 3.08	109%	418%	421%	514%	129%
2018/19	$ 3.38	$ 5.77	$ 5.45	$ 5.40	$ 3.38	59%	315%	318%	329%	108%
2019/20	$ 2.13	$ 3.46	$ 3.21	$ 3.16	$ 2.03	43%	260%	291%	280%	38%
2020/21	$ 3.13	$ 4.46	$ 4.79	$ 4.48	$ 2.71	174%	356%	363%	382%	121%
2021/22	$ 4.55	$ 11.68	$ 9.73	$ 10.53	$ 4.40	62%	436%	531%	505%	54%
2022/23	$ 4.07	$ 8.47	$ 9.52	$ 7.05	$ 3.95	97%	439%	568%	501%	102%

With respect to gas price volatility (i.e., a measure of the degree of price variations),[73] as shown in Table III-6 (above), the volatility level for the New England market area price indices have been well above 100 percent every winter, with the simple average daily prices during the winter period exceeding $5/MMBtu in 8 of the 13 winters. Stated differently, the New England market area prices have experienced large price fluctuations at high price levels in 8 of the last 13 winters. In contrast, the Dawn Hub index has only one observation with relatively high volatility, which reflected certain price spikes at the Dawn Hub in the colder-than-normal winter of 2013/14; five observations with volatility levels between 100 percent and 150 percent and price levels below $4/MMBtu; and seven observations with volatility levels well below 100 percent and price levels between $2-5/MMBtu.

Notably, as discussed later in Section VII.D.2, the Company engages in supply and price risk management activities to mitigate exposure to the volatility of daily prices. These activities are periodically reviewed by the Maine and New Hampshire Public Utilities Commissions in Northern's Cost of Gas filings.

4. Energy and Environmental Policy

Federal and many state policymakers, including in the New England region, are promoting a major energy transition away from fossil fuels and toward a decarbonized energy system. At the federal level, recent climate-related policies are aimed at accelerating the reduction in emissions (e.g., Inflation Reduction Act Methane Emissions Charge) and supporting the growth of clean energy sources (e.g., EPA's proposed rule changes to the Renewable Fuel Standard). At the regional level, the six New England states have been working to reduce GHG emissions through state goals and legislative mandates, as well as

[72] Based on ScottMadden's analysis of data from S&P Capital IQ. Note: Winter 2022/23 includes data through March 14, 2023.
[73] Historical price volatility is calculated as the standard deviation of daily relative changes in natural gas prices. Source: U.S. Energy Information Administration, An Analysis of Price Volatility in Natural Gas Markets, August 2007.

regional agreements.[74] For example, in New Hampshire, the state's Climate Action Plan published in 2009 called for a reduction in GHG emissions of 80 percent below 1990 levels by 2050; and in Maine, an Act to Promote Clean Energy Jobs and to Establish the Maine Climate Council, which was passed in 2019, requires the state to reduce GHG emissions to 45 percent below 1990 levels by 2030 and 80 percent by 2050.

However, there is considerable uncertainty with respect to the role and impact of the various energy and environmental policies on future natural gas demand, supply, and costs/pricing. For example, in Massachusetts, the Department of Public Utilities ("DPU") is currently reviewing the role of the Massachusetts gas LDCs in support of the Commonwealth's 2050 climate goals of net-zero GHG emissions in Docket DPU 20-80. As part of the DPU 20-80 proceeding, various pathways to achieve net zero emissions were evaluated, which were highly dependent on assumptions regarding fundamental factors, such as the availability of renewable gas and pace and magnitude of technology adoption, and, thus, inherently subject to substantial forward-looking uncertainties. In addition, the pathways evaluated in the DPU 20-80 proceeding resulted in an extremely wide range of outcomes across pathways with meaningfully different implications on natural gas demand, supply, and costs over the coming decades.

For Northern, and its parent (Unitil Corporation), the trends in energy and environmental policy to address climate change continue to influence and inform its approach to decarbonization and GHG emissions reductions. As discussed in Unitil Corporation's *2022 Corporate Sustainability and Responsibility Report*,[75] the Company and its parent fully embrace the imperative to achieve net-zero emissions by 2050. Efforts to achieve net-zero emissions over the coming decades include: increasing Energy Efficiency, reducing the percentage of leak prone pipe on its distribution system and level of emissions from its fleet and facilities, decarbonizing gas supply (e.g., opportunities to decrease the carbon content of the gas supply portfolio by procuring and utilizing renewable gas and certified gas), and promotion of environmentally-friendly heating sources and technologies.

Nevertheless, given the level of uncertainty regarding the impact of climate-related policies on long-term natural gas demand and supply, it is imperative that Northern's resource portfolio achieves resource adequacy (the Company's resource portfolio is capable of meeting its Planning Load) and that the Company preserves flexibility and optionality as the natural gas market landscape continues to evolve to address state and regional climate goals and policies, and customer preferences.

[74] See, ISO Newswire, "The New England states' frameworks for reducing greenhouse gas emissions continue to evolve," January 19, 2021.
[75] See, https://unitil.com/reports/2022-Sustainability-Report/. Unitil's Carbon emissions reduction target is company-wide direct greenhouse gas emissions reduction from 2019 levels by at least 50 percent by 2030, and to net-zero emissions by 2050.

IV. New Hampshire Capital Budget

Key Takeaways

Key takeaways in this chapter include the following:

- *The Company maintains a mature and robust capital planning process designed to provide safe, reliable, and affordable service. Capital planning begins with engineering assessments of load growth and hydraulic modeling of the distribution system under normal and design operating conditions. The Company develops a detailed 5-year capital budget annually.*
- *As directed in NHPUC Order 26,664 (August 8, 2022), the Company provides its current New Hampshire Division capital budget, as well as a 5-year history of actual capital spending. The materials provided below are in the format used by the Company, and provided in functional view by major category along with project view narrative detail for projects costing $200,000 or more.*

A. Introduction

This New Hampshire Capital Budget section is organized as follows:

Part B, Capital Planning Process, provides an overview of the Company's annual budgeting process, requirements and standards;

Part C, New Hampshire System Capital Budget, provides a 5-year history of actual capital spending and the Company's current New Hampshire Division 5-year capital budget presented in summary and in detail by functional category, along with project narratives for budget items greater than $200,000.

B. Capital Budget Process

1. Distribution System Planning

The main objective of Northern's planning process is to provide safe and reliable service in the most economical manner. The planning process starts with engineering studies performed by the Company's engineering group. This includes network studies performed via hydraulic modeling and simulation of integrated, multi-pressure-level systems including regulator stations. These studies are updated with the latest load forecasts and identify both short term and long-term needs. The purpose of the studies is to determine when system growth is likely to cause unacceptable pressure conditions on the distribution system. The study examines the distribution system under design day conditions in its normal operating condition as well as in response to design contingencies. The study generally covers a ten-year timeframe. Engineering planning studies are the first and most important input into the capital planning process.

2. Load Growth Rate Analysis

In order to determine load growth, the historical customer and supply point monthly volumetric usage were analyzed to determine the usage per degree day ("UDD") for each year and subsequently the annual percent change. This analysis is performed using a global data regression determined from the flow rate data collected at each supply point present within the Northern systems (i.e. Newington, Pleasant St., and Westbrook Interconnects, and the Salem, Debbie Ln., and Cotton Rd. City Gate Stations and the Lewiston LNG Plant.). The regression analysis is designed to determine the base load (usage at a 0 Effective Degree Day ("EDD")) and a UDD. This resulted in an average growth in UDD of 1.333% per year.

3. Network Modeling

The Northern system simulations were performed (using Synergi Gas 4.9.2) for an 80 EDD and peak hourly demands using a peaking factor of 0.051. The annual growth rate was applied to the entirety of the Northern distribution systems to simulate ten years of compounding load growth. Lastly, the system improvements that have been documented within the five-year budget have been modeled for each successive year. However, after five years the model remains unchanged and only load is increased. Inherently, this allows for new system improvements to be identified. Any high pressure ("HP") or intermediate pressure ("IP") system that experiences pressures below one-half of the MAOP are identified as requiring a system improvement. Low pressure ("LP") systems are not to operate below 5.5 IN W.C.

4. Capital Budgeting Development

Each year Northern develops a line-by-line, project-by-project five-year capital budget. The Company does not complete a budget for years 6-10 because the level of accuracy decreases and the level of uncertainty increases with each subsequent year. In addition, there is little value to complete capital budgets for years 6-10 because the Company refreshes the five-year budget every year to include the most up to date information.

In advance of the budget cycle each year, instructions are provided to all budget managers and other contributors that define expectations for the proper development and justification of projects. These instructions ensure that individual budget items are well defined, estimated and justified, and ensure accurate and consistent entry into the budget system. The goal of this process is to streamline the review and approval process once budgets are approved. Specifically, each submitted project is expected to meet the following requirements:

- Each project must have a well-defined project scope, which fully describes the project and the extent of work to be undertaken.
- Each project must also have a detailed justification that describes the need for the project, including quantitative analysis where possible.
- The cost of each project is estimated to a level of accuracy of 90% or better.

In general, projects that are not well defined and appropriately justified are not included in the budget. Project entries intended to be "place holders" for undefined plans or needs are not accepted. This allows management to efficiently and effectively review priorities and spending, and ensure an appropriate level of funding for important projects.

The engineering group identifies the need for system improvement and reinforcement projects. Operations personnel identify the need for condition replacements based on inspection and maintenance programs. Budgets are constructed using a "bottom up" process each year with input from dozens of engineering and operations employees. Technical and managerial personnel with responsibility for planning, designing, operating and maintaining the gas delivery system are responsible for identifying needs and developing cost-effective solutions. A multistep process is used to budget hundreds of individual projects, and to then prioritize needs and determine which projects are essential to meet our objective of safe and reliable service for our customers. Projects are also proposed that may not be essential, but which represent an improvement or enhancement to existing systems or capabilities, including projects to improve reliability, replace old or obsolete equipment, and projects with a defined economic payback.

After several rounds of review involving multiple levels of engineering and operations management, a preliminary budget is recommended to senior management for review and approval. Upon approval by senior management, the final budget is presented to the Board of Directors for final approval.

C. New Hampshire System Capital Budget

1. Historical and Forecast Capital Spending

The table below provides the historical capital budget spending from the 5-year period of 2018-2022 by major functional category.

Table IV-1: Historical NH Division Capital Spending ($000's)

	Actual Spending (000's)				
Description	**2018**	**2019**	**2020**	**2021**	**2022**
Annual Requirements	$ 7,284.30	$ 6,356.20	$ 7,605.90	$ 8,534.00	$ 9,615.80
Blankets Water Heater	$ 185.60	$ 144.10	$ 101.90	$ 157.70	$ 153.30
Communications	$ 408.50	$ 679.20	$ 823.90	$ 729.00	$ 950.80
Mains Extensions	$ 3,731.80	$ 4,095.10	$ 5,551.50	$ 1,291.10	$ 1,410.40
Highway Projects	$ 8,486.70	$ 1,576.20	$ 1,746.40	$ 1,816.10	$ 2,010.00
Asphalt Restoration	$ 704.80	$ 330.70	$ 757.10	$ 410.10	$ 797.60
Specific Distribution Projects	$ 2,053.90	$ 10,334.90	$ 6,205.90	$ 10,759.00	$ 4,118.50
Tools and Equipment	$ 33.20	$ 61.70	$ 110.00	$ 299.20	$ 184.80
Office	$ 5.90	$ 18.90	$ 10.80	$ 17.10	$ 14.60
Structures	$ 387.30	$ 31.40	$ 1.60	$ 5.00	$ 47.60
Total	**$ 23,282.00**	**$ 23,628.40**	**$ 22,915.00**	**$ 24,018.30**	**$ 19,303.40**

The following table provides a summary of the five-year capital budget.

Table IV-2: Forecast NH Division Capital Spending ($000's)

	Forecast Spending (000's)				
Description	**2023**	**2024**	**2025**	**2026**	**2027**
Annual Requirements	$ 9,623.90	$ 9,676.24	$ 10,533.32	$ 10,911.82	$ 11,627.34
Blankets Water Heater	$ 247.60	$ 255.39	$ 262.98	$ 262.98	$ 263.10
Communications	$ 1,266.02	$ 1,575.00	$ 1,725.15	$ 1,697.18	$ 1,913.30
Mains Extensions	$ 1,519.46	$ 1,168.56	$ 1,453.72	$ 1,631.21	$ 1,684.67
Highway Projects	$ 1,448.45	$ 1,072.85	$ 1,329.28	$ 1,569.75	$ 1,609.40
Asphalt Restoration	$ 737.46	$ 816.64	$ 1,047.66	$ 1,004.52	$ 1,023.26
Specific Distribution Projects	$ 8,893.04	$ 7,460.20	$ 5,390.96	$ 7,710.11	$ 8,038.35
Tools and Equipment	$ 379.76	$ 273.32	$ 157.42	$ 158.55	$ 118.05
Office	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
Structures	$ 68.00	$ 1,170.00	$ 1,100.00	$ 2,155.00	$ 855.00
Total	**$ 24,188.70**	**$ 23,473.19**	**$ 23,005.50**	**$ 27,106.11**	**$ 27,137.47**

The following sections describe each of the budget categories and describes the projects with a budget estimate in excess of $200,000.

2. Annual Requirements

These are blanket projects which are not defined with specificity at budget time. The budget estimate for these budget categories is based upon historical spending with estimated annual increases in labor rates, contractor rates and material and equipment costs. This category includes blanket authorizations for categories of projects where each individual project is small in value (under $40,000) and cannot be individually anticipated at budget time. These projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending.

Table IV-3: Forecast Annual Requirement Spending ($000's)

Budget Code	Budget #	Annual Requirements	2023	2024	2025	2026	2027
MAB		Distribution System Improvements	$ 798.28	$ 785.31	$ 804.43	$ 789.17	$ 802.73
MAC		Distribution System Improvements, Carryover	$ 20.14	$ 21.81	$ 22.33	$ 21.03	$ 21.47
MBB		New Gas Services	$ 1,701.28	$ 1,425.80	$ 2,275.56	$ 2,085.03	$ 2,155.66
MBC		New Gas Services, Carryover	$ 36.98	$ 39.55	$ 41.35	$ 39.27	$ 39.12
MCB		Corrosion Control	$ 174.56	$ 192.27	$ 201.84	$ 192.73	$ 196.38
MDB		Abandoned Gas Services	$ 216.73	$ 233.76	$ 205.36	$ 200.12	$ 202.72
MDC		Abandoned Gas Services, Carryover	$ 10.42	$ 11.30	$ 11.37	$ 10.86	$ 10.91
MEB		Gas Service Upgrades	$ 1,322.64	$ 1,372.95	$ 2,272.55	$ 1,479.32	$ 2,143.20
MEC		Gas Service Upgrades, Carryover	$ 13.24	$ 14.34	$ 14.57	$ 13.78	$ 13.85
MFB		Meter Installations – Company	$ 992.40	$ 1,058.77	$ 1,278.52	$ 1,089.28	$ 1,128.71
MFC		Meter Installations – Company Carryover	$ 8.31	$ 8.88	$ 8.77	$ 8.21	$ 8.34
MGB		Meter Installations – Customer	$ 972.91	$ 1,103.67	$ 1,369.03	$ 1,261.85	$ 1,296.92
MGC		Meter Installations – Customer	$ 8.31	$ 8.88	$ 8.77	$ 8.22	$ 8.35
MHB		Meter Purchases – Company	$ 1,328.42	$ 1,777.84	$ 193.70	$ 1,884.08	$ 1,760.85
MHC		Meter Purchases – Company Carryover	$ 511.58	$ 81.75	$ 84.41	$ 78.58	$ 77.72
MIB		Meter Purchases – Customer	$ 701.45	$ 991.43	$ 1,074.93	$ 1,050.67	$ 981.95
MIC		Meter Purchases – Customer Carryover	$ 279.74	$ 32.70	$ 33.77	$ 31.43	$ 31.09
MMB		Gas System Improve - System Ops	$ 467.23	$ 448.22	$ 555.86	$ 597.23	$ 677.20
MMC		GasSystem Improve - System Ops - Carryover	$ 59.31	$ 67.04	$ 76.23	$ 70.96	$ 70.18
		Sub-Totals:	$ 9,623.90	$ 9,676.24	$ 10,533.32	$ 10,911.82	$ 11,627.34

Annual Requirement Projects exceeding $200,000:

- Distribution Improvements – include minor improvements, replacements and repairs to the distribution system. The estimate for this project is derived from historical spending with a slight increase in the cost of labor, contract services, and materials.

- New Customer Additions – include projects to serve new customer requests including new services and small main extensions. The estimate for this project is derived from historical spending with a slight increase in the cost of labor, contract services, and materials.

- Abandoned Services - includes costs to cut and permanently abandon unused services in accordance with regulations. The abandonment of inactive gas services is a Federal requirement in accordance with CFR 149 and a State requirement in accordance with PUC 500. All services that have been inactive for (3) years, unless the service is plastic or cathodically protected steel, must be physically disconnected (i.e. abandoned) at the main. A plastic or cathodically protected steel service must be abandoned no later than (10) years from the most recent inactivation date. The estimate for this project is derived from the estimated number of services to be replaced with a slight increase in the cost of labor, contract services, and materials.

- Meter Installations (Company and Customer) – Includes the labor and materials required for the installation of metering and piping on company or customer driven projects. Company driven projects include sample meter changeouts to facilitate testing. Customer driven projects include new meter installations and meter exchanges for increased load. The estimate for this project is derived from historical spending with a slight increase in the cost of labor, contract services, and materials.

- Meter Purchases (Company and Customer) – includes the purchase of gas meters, instruments, modems, drive arms and ERTS (communication devices) associated with new meters as well as routine sample replacement of meters. The estimate for this project is derived from historical spending with a slight increase in the cost of labor, contract services, and materials.

- Gas System Improvements – includes normal additions and replacement of equipment and components in gas metering and pressure regulating facilities including labor and contract services for equipment installation. Included are pressure regulators, valves, instrumentation, pressure recorders, pipe, pipe fittings and other equipment associated with gate stations and regulator stations. The estimate for this project is derived from historical spending with a slight increase in the cost of labor, contract services, and materials.

3. Blankets Water Heater

These are blanket projects which are not defined with specificity at budget time. This category includes blanket authorizations for categories of projects where each individual project is small in value (under $40,000) and cannot be individually anticipated at budget time. These projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. Blankets Water Heater cover the purchase and installation of new and replacement water heater and conversion burner products for customers who purchase or rent their water heaters through the

Company. The budget estimate for is based upon historical spending with estimated annual increases in labor rates, contractor rates and material and equipment costs.

Table IV-4: Forecast Blanket Water Heater Spending ($000's)

Budget Code	Budget #	Blankets:Water Heater	2023	2024	2025	2026	2027
MJB		New Water Heaters and Conversion Burners	$ 125.00	$ 130.00	$ 133.90	$ 133.90	$ 134.00
MJC		New Water Heaters and Conversion Burners, Carryover	$ 1.30	$ 1.20	$ 1.20	$ 1.20	$ 1.20
MKB		Replacement Water Heater & Conversion Burner	$ 120.00	$ 122.99	$ 126.68	$ 126.68	$ 126.70
MKC		Replacement Water Heater & Conversion Burner, Carryover	$ 1.30	$ 1.20	$ 1.20	$ 1.20	$ 1.20
		Sub-Totals:	$ 247.60	$ 255.39	$ 262.98	$ 262.98	$ 263.10

There are no Blanket Water Heater projects budgeted to exceed $200,000. The blankets water heater categories include:

- New Water Heaters and Conversion Burners – include the purchase and installation of new water heaters and conversion burners.
- Replacement Water Heaters and Conversion Burners – include the purchase and installation of replacement water heaters and conversion burners.

4. Communications

These are specific software and networking projects identified during the budget process. These projects are authorized at the service company level and allocated across the Unitil subsidiaries, including Northern. These software projects are typically allocated across each of the Unitil subsidiaries based upon a cost allocation calculation based upon number of customers, revenue, and net plant. The table below provides the allocation to Northern NH.

Table IV-5: Forecast Communications Spending ($000's)

Budget #	Communications	2023	2024	2025	2026	2027
GSC01	Power Plan Upgrade 2023	$ 70.30	$ -	$ -	$ -	$ -
GSC02	General Software Enhancements 2023	$ 15.20	$ -	$ -	$ -	$ -
GSC04	Reporting Blanket 2023	$ 18.62	$ -	$ -	$ -	$ -
GSC05	OT Security and Visibility Enhancements 2023	$ 23.17	$ -	$ -	$ -	$ -
GSC06	CIS Enhancements Blanket 2023	$ 7.60	$ -	$ -	$ -	$ -
GSC07	Metersense Upgrade 2023	$ 12.60	$ -	$ -	$ -	$ -
GSC09	Regulatory Work Blanket 2023	$ 5.70	$ -	$ -	$ -	$ -
GSC12	Web Ops Modernization Blanket 2023	$ 12.97	$ -	$ -	$ -	$ -
GSC56	FCS Upgrade 2023	$ 3.42	$ -	$ -	$ -	$ -
GSC63	Cyber Managed Response	$ 58.33	$ -	$ -	$ -	$ -
GSC64	Leakage Data Enhancement	$ 9.69	$ -	$ -	$ -	$ -
GSC67	Utility Bill Redesign - Carryover	$ 16.06	$ -	$ -	$ -	$ -
GSC69	Modernize GTRAC & CSI - Carryover	$ 19.72	$ -	$ -	$ -	$ -
GSC78	Performance Management System	$ 11.40	$ -	$ -	$ -	$ -
GSC80	Locusview Mobile Upgrade to V3 (Carry over)	$ 35.70	$ -	$ -	$ -	$ -
GSC82	enQuesta Ver. 6.0 Upgrade - Carryover	$ 660.56	$ -	$ -	$ -	$ -
GPC02	IT Infrastructure 2023	$ 190.00	$ -	$ -	$ -	$ -
GPC03	IT Network Segmentation 2023	$ 95.00	$ -	$ -	$ -	$ -
GSC03	Metersense Upgrade 2024	$ -	$ 9.50	$ -	$ -	$ -
GSC05	General Software Enhancements 2024	$ -	$ 47.50	$ -	$ -	$ -
GSC06	Reporting Blanket 2024	$ -	$ 9.26	$ -	$ -	$ -
GSC08	Web Ops Modernization Blanket 2024	$ -	$ 47.50	$ -	$ -	$ -
GSC09	Cloud Discovery and Migration Work 2024	$ -	$ 38.00	$ -	$ -	$ -
GSC10	DevOps Implementation Project 2024	$ -	$ 47.50	$ -	$ -	$ -
GSC10	Energy Marketplace (Integrated Vendor Solution)	$ -	$ 76.00	$ -	$ -	$ -
GSC20	Capital Budget System - Carry-over	$ -	$ 57.00	$ -	$ -	$ -
GSC23	AOC Click to Report System	$ -	$ 34.20	$ -	$ -	$ -
GSC45	FCS Upgrade 2024	$ -	$ 3.42	$ -	$ -	$ -
GSC46	Locusview Mobile / CMS Integration	$ -	$ 10.20	$ -	$ -	$ -
GSC47	enQuesta Ver. 6.0 Upgrade, Carryover	$ -	$ 80.75	$ -	$ -	$ -
GSC48	Regulatory Work Blanket 2024	$ -	$ 19.00	$ -	$ -	$ -
GSC51	MV-90xi Upgrade V7.0 to X.0 2024	$ -	$ 18.05	$ -	$ -	$ -
GSC53	Power Plan Updated License	$ -	$ 57.00	$ -	$ -	$ -
GSC54	CIS Enhancements Blanket 2024	$ -	$ 19.00	$ -	$ -	$ -
GSC56	OT Security and Visibility Enhancements 2024	$ -	$ 28.50	$ -	$ -	$ -
GSC58	Self Service Analytics and Data Marts 2024	$ -	$ 76.00	$ -	$ -	$ -
GSC61	Advanced Rate Design 2024	$ -	$ 47.50	$ -	$ -	$ -
GSC63	ERP 2024	$ -	$ 266.00	$ -	$ -	$ -
GSC64	Customer Video Messaging - SmartVX	$ -	$ 19.00	$ -	$ -	$ -
GSC65	Customer Bill Analysis Tool	$ -	$ 38.00	$ -	$ -	$ -
GSC67	EMIS Sunset	$ -	$ 57.00	$ -	$ -	$ -
GSC68	Methane Emissions Calculator	$ -	$ 17.85	$ -	$ -	$ -
GSC69	ITS On the Job Training Digitized Books	$ -	$ 1.43	$ -	$ -	$ -
GSC71	Data Sharing: Unitil Core Platform Design - Carryover	$ -	$ 114.00	$ -	$ -	$ -
GSC72	Integrate FCS to Provide Meter Location & Hazards	$ -	$ 3.34	$ -	$ -	$ -
GSC73	HR Information System (HRIS)	$ -	$ 28.50	$ -	$ -	$ -
GPC02	Cyber Security Enhancements 2024	$ -	$ 19.00	$ -	$ -	$ -
GPC05	IT Infrastructure 2024	$ -	$ 190.00	$ -	$ -	$ -
GPC06	IT Network Segmentation 2024	$ -	$ 95.00	$ -	$ -	$ -
GSC01	GIS Upgrade to Utility Network	$ -	$ -	$ 75.05	$ -	$ -
GSC02	Metersense Upgrade 2025	$ -	$ -	$ 9.50	$ -	$ -
GSC07	Regulatory Work Blanket 2025	$ -	$ -	$ 19.00	$ -	$ -
GSC23	General Software Enhancements 2025	$ -	$ -	$ 47.50	$ -	$ -
GSC24	Reporting Blanket 2025	$ -	$ -	$ 9.26	$ -	$ -
GSC25	Web Ops Modernization Blanket 2025	$ -	$ -	$ 47.50	$ -	$ -
GSC26	Cloud Discovery and Migration Work 2025	$ -	$ -	$ 76.00	$ -	$ -
GSC27	DevOps Implementation Project 2025	$ -	$ -	$ 91.68	$ -	$ -
GSC33	CIS Enhancements Blanket 2025	$ -	$ -	$ 19.00	$ -	$ -
GSC36	OT Security and Visibility Enhancements 2025	$ -	$ -	$ 28.50	$ -	$ -
GSC55	Data Sharing: OT 2025	$ -	$ -	$ 47.50	$ -	$ -
GSC59	Unitil Enterprise Service Bus	$ -	$ -	$ 14.25	$ -	$ -
GSC60	Smartworks Automated Move-in / Move-out & Connect/Disconnect Automation modules	$ -	$ -	$ 45.70	$ -	$ -

Table IV-5: Forecast Communication Spending ($000's) – continued

Budget #	Communications	2023	2024	2025	2026	2027
GSC61	FCS Upgrade 2025	$ -	$ -	$ 3.42	$ -	$ -
GSC62	MV-90xi Upgrade V7.0 to X.0 2025	$ -	$ -	$ 18.05	$ -	$ -
GSC62	MyHQ- Enhancement to Enrolled Profile- Web Portal	$ -	$ -	$ 38.00	$ -	$ -
GSC63	Advanced Rate Design 2025	$ -	$ -	$ 47.50	$ -	$ -
GSC64	Additional Payment Options	$ -	$ -	$ 23.75	$ -	$ -
GSC65	ERP 2025	$ -	$ -	$ 380.00	$ -	$ -
GSC66	enQuesta Link Work Order System	$ -	$ -	$ 171.00	$ -	$ -
GSC66	Strategic Data Substrate (SDS)	$ -	$ -	$ 38.00	$ -	$ -
GSC68	Enterprise Service Bus Development - 2025	$ -	$ -	$ 61.75	$ -	$ -
GSC69	Data Sharing: System Data Module	$ -	$ -	$ 47.50	$ -	$ -
GSC70	Self Service Analytics and Data Marts 2025	$ -	$ -	$ 23.75	$ -	$ -
GPC01	Cyber Security Enhancements 2025	$ -	$ -	$ 19.00	$ -	$ -
GPC04	IT Infrastructure 2025	$ -	$ -	$ 228.00	$ -	$ -
GPC05	IT Network Segmentation 2025	$ -	$ -	$ 95.00	$ -	$ -
GSC01	Metersense Upgrade 2026	$ -	$ -	$ -	$ 9.50	$ -
GSC02	AMI Command Center Upgrade - 2026	$ -	$ -	$ -	$ 17.48	$ -
GSC02	Work Order Job Scheduler	$ -	$ -	$ -	$ 66.50	$ -
GSC06	Sharepoint Upgrade	$ -	$ -	$ -	$ 19.00	$ -
GSC28	Data Sharing: Behind the Meter Enhancements	$ -	$ -	$ -	$ 47.50	$ -
GSC32	Energy Marketplace (Enhancements) 2026	$ -	$ -	$ -	$ 95.00	$ -
GSC39	Containerization of Unitil Servers 2026	$ -	$ -	$ -	$ 47.50	$ -
GSC52	FCS Upgrade 2026	$ -	$ -	$ -	$ 3.42	$ -
GSC53	MV-90xi Upgrade V8.0 to X.0 2026	$ -	$ -	$ -	$ 18.05	$ -
GSC54	Power Plant Upgrade 2026	$ -	$ -	$ -	$ 89.30	$ -
GSC56	CIS Enhancements Blanket 2026	$ -	$ -	$ -	$ 19.00	$ -
GSC58	General Software Enhancements 2026	$ -	$ -	$ -	$ 66.50	$ -
GSC59	Reporting Blanket 2026	$ -	$ -	$ -	$ 19.00	$ -
GSC60	Regulatory Work Blanket 2026	$ -	$ -	$ -	$ 19.00	$ -
GSC64	Web Ops Modernization Blanket 2026	$ -	$ -	$ -	$ 95.00	$ -
GSC67	Smart Speaker Integration	$ -	$ -	$ -	$ 28.50	$ -
GSC67	Advanced Rate Design 2026	$ -	$ -	$ -	$ 47.50	$ -
GSC68	ERP 2026	$ -	$ -	$ -	$ 380.00	$ -
GSC69	Data Sharing 2026	$ -	$ -	$ -	$ 66.50	$ -
GSC70	OT Security and Compliance Enhancements 2026	$ -	$ -	$ -	$ 38.00	$ -
GSC71	Self Service Analytics and Data Marts 2026	$ -	$ -	$ -	$ 28.50	$ -
GSC72	Enterprise Service Bus Development - 2026	$ -	$ -	$ -	$ 42.75	$ -
GSC73	DevOps Implementation Project 2026	$ -	$ -	$ -	$ 47.50	$ -
GSC74	Cloud Discovery and Migration Work 2026	$ -	$ -	$ -	$ 47.50	$ -
GPC02	Cyber Security Enhancements 2026	$ -	$ -	$ -	$ 33.25	$ -
GPC04	Cell modem network updates 4G to 5G	$ -	$ -	$ -	$ 20.43	$ -
GPC06	IT Network Segmentation 2026	$ -	$ -	$ -	$ 95.00	$ -
GPC09	IT Infrastructure 2026	$ -	$ -	$ -	$ 190.00	$ -
GSC01	Metersense Upgrade 2027	$ -	$ -	$ -	$ -	$ 9.50
GSC02	AMI Command Center Upgrade - 2027	$ -	$ -	$ -	$ -	$ 17.48
GSC03	FCS Upgrade 2027	$ -	$ -	$ -	$ -	$ 3.42
GSC04	MV-90xi Upgrade VX.0 to X.0 2027	$ -	$ -	$ -	$ -	$ 18.05
GSC05	Advanced Rate Design 2027	$ -	$ -	$ -	$ -	$ 47.50
GSC29	Energy Marketplace (Enhancements) 2027	$ -	$ -	$ -	$ -	$ 95.00
GSC30	Cyber Security Enhancements 2027	$ -	$ -	$ -	$ -	$ 38.00
GSC31	Regulatory Work Blanket 2027	$ -	$ -	$ -	$ -	$ 19.00
GSC32	WebOps Modernization Blanket 2027	$ -	$ -	$ -	$ -	$ 95.00
GSC33	Reporting Blanket 2027	$ -	$ -	$ -	$ -	$ 20.90
GSC34	General Software Enhancements 2027	$ -	$ -	$ -	$ -	$ 79.80
GSC35	CIS Enhancements Blanket 2027	$ -	$ -	$ -	$ -	$ 19.00
GSC36	Data Sharing 2027	$ -	$ -	$ -	$ -	$ 66.50
GSC37	OT Security and Compliance Enhancements 2027	$ -	$ -	$ -	$ -	$ 38.00
GSC39	Project Management Software	$ -	$ -	$ -	$ -	$ 11.40
GSC41	Self Service Analytics and Data Marts 2027	$ -	$ -	$ -	$ -	$ 28.50
GSC44	Communications Upgrades (Modems, Cell, 5G)	$ -	$ -	$ -	$ -	$ 76.00
GSC45	Enterprise Service Bus Development - 2027	$ -	$ -	$ -	$ -	$ 28.50
GSC61	Containerization of Unitil Servers 2027	$ -	$ -	$ -	$ -	$ 61.75
GSC63	ERP 2027	$ -	$ -	$ -	$ -	$ 817.00
GPC02	IT Infrastructure 2027	$ -	$ -	$ -	$ -	$ 228.00
GPC03	IT Network Segmentation 2027	$ -	$ -	$ -	$ -	$ 95.00

Communication Projects exceeding $200,000:

- enQuesta Version 6 Upgrade - The enQuesta Version 6.0 upgrade is a major upgrade to the CIS as the architecture is completely changing. Customer Information System (CIS) will upgrade to the latest version 6.0 and inherit new functionality. Capricorn will be implemented as a new Customer Engagement Management (CEM) tool to replace the existing WebConnect application that is no longer being supported by the vendor. The Kubra EZ-Pay platform will be upgraded to the latest version 5.1. Middleware technology will be developed to act as software bridge between systems to support the integration between the Unitil Data Exchange and CIS system. This upgrade allows for compliance with the security requirement to be on Oracle version 19C which our current enQuesta version 4.7 does not support.

- Enterprise Resource Planning (ERP) – This project is to implement an ERP system that will provide a modern technology platform with various modules. This ERP system will replace the Company's current general ledger, accounts payable, materials & supplies, cash management, workflow, and other legacy systems with an integrated solution. This integrated solution will, among other things, enhance the Company's internal controls, provide centralized and standardized data and reporting, increase productivity, automate workflow and other activities, allow for real-time reporting, and a better employee experience. The project outcome is an integrated solution that provides the accounting, finance, regulatory, and other departments with accurate, complete, relevant, and timely data necessary to effectively manage the business and allocate resources. The Company's current technology infrastructure that supports accounting, finance, shared services, human resources, and other departments is comprised of external vendor software and internally developed software, some of which is over 20 years old (for example, Flexi was implemented in 1998). This current technology infrastructure lacks functionality and performance that is inherent in modern ERP systems and is challenging and costly to maintain. The ERP system will enhance and strengthen the Company's ability to meet its significant reporting requirements and its high standards of operational excellence. The Company is in the early stages of investigation. A more detailed project plan, schedule and estimate will be developed.

- IT Infrastructure – includes the purchase and installation of desktop, server and network hardware equipment. This is an annual project similar to the blanket projects identified above. The estimate for this project is derived from historical spending with a slight increase in the cost of labor and equipment.

5. Distribution Projects

This section covers four of the functional line item categories listed in Table IV-2, the capital budget forecast. The functional categories include Mains Extensions, Highway Projects, Asphalt Restoration and Specific Distribution Projects. These are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. This work includes main extensions, which are new extensions of gas pipeline facilities required to provide service to new customers; unprotected pipe replacement, which involves the replacement of cast iron and bare steel mains; highway projects, which typically involve relocations driven by state or municipal roadway projects including municipal sewer separation projects; distribution improvements, which are improvements, replacements and repairs to the distribution system that cannot be completed under blanket authorizations; valve installations, which include the capital cost of distribution and excess flow valve installations; and other specific projects in excess of $40,000, which are identified by engineering or others that are needed to meet service obligations.

Table IV-6: Forecast Distribution Project Spending ($000's)

Budget Code	Budget #	Distribution Projects	2023	2024	2025	2026	2027
JAB	0	Main Extensions	$ 1,289.85	$ 1,083.89	$ 1,364.22	$ 1,547.24	$ 1,600.99
JAC	0	Main Extensions, Carryover	$ 229.61	$ 84.67	$ 89.51	$ 83.96	$ 83.68
JHB	0	Gas Highway Projects, Budgeted	$ 1,436.08	$ 1,059.23	$ 1,314.82	$ 1,556.01	$ 1,595.36
JHC	0	Gas Highway Projects, Carryover	$ 12.37	$ 13.62	$ 14.46	$ 13.74	$ 14.04
JPB	1	Asphalt Restoration 2022 Projects	$ 737.46	$ -	$ -	$ -	$ -
JPB	2	Asphalt Restoration 2023 Projects	$ -	$ 816.64	$ -	$ -	$ -
JPB	3	Asphalt Restoration 2024 Projects	$ -	$ -	$ 1,047.66	$ -	$ -
JPB	4	Asphalt Restoration 2025 Projects	$ -	$ -	$ -	$ 1,004.52	$ -
JPB	5	Asphalt Restoration 2026 Projects	$ -	$ -	$ -	$ -	$ 1,023.26
JPB	10	Commercial/Industrial LVM Upgrades & Replacements	$ -	$ -	$ -	$ -	$ 183.96
JPB	18	Farm Tap Replacement	$ -	$ -	$ 519.00	$ -	$ -
JPB	19	Farm Tap Replacement	$ -	$ -	$ -	$ 651.16	$ -
JPB	20	Farm Tap Replacement	$ -	$ -	$ -	$ -	$ 707.09
JPB	21	Regulator Station OPP/Redundancy	$ -	$ 688.94	$ -	$ -	$ -
JPB	24	Regulator Station OPP/Redundancy	$ -	$ -	$ -	$ -	$ 437.37
JPB	28	Regulator Station Physical Security Improvements	$ -	$ -	$ -	$ 256.52	$ -
JPB	29	Regulator Station Physical Security Improvements	$ -	$ -	$ -	$ -	$ 254.40
JPB	52	Hawthorne/Applevale Stations Rebuild - Distribution Tie-In	$ 385.09	$ -	$ -	$ -	$ -
JPB	53	Hawthorne/Applevale Stations Rebuild-PHASE 2	$ 2,489.43	$ -	$ -	$ -	$ -
JPB	54	Salem Gate Station Meter & By-Pass Run Upgrade	$ 635.02	$ -	$ -	$ -	$ -
JPB	55	Water St Exeter Main Replacement	$ 375.28	$ -	$ -	$ -	$ -
JPB	60	Blackwater Rd Somersworth Improvement-Phase 1	$ 1,471.91	$ -	$ -	$ -	$ -
JPB	61	Bartlett Avenue/High Street Stations Rebuild – Distribution Tie-in	$ 851.03	$ -	$ -	$ -	$ -
JPB	62	Bartlett Avenue/High Street Stations Rebuild-Complete Rebuild	$ 2,332.41	$ -	$ -	$ -	$ -
JPB	80	Blackwater Rd Somersworth Improvement-Phase 2	$ -	$ 2,834.70	$ -	$ -	$ -
JPB	81	Nimble Hill Rd. Station Distribution Tie-In	$ -	$ 400.23	$ -	$ -	$ -
JPB	82	Nimble Hill Road Station Replacement-492PSIG to 56PSIG	$ -	$ 3,536.33	$ -	$ -	$ -
JPB	83	Route 151 System Merger	$ -	$ -	$ 953.40	$ -	$ -
JPB	84	Pease Boulevard Regulator Station (New)	$ -	$ -	$ 3,660.32	$ -	$ -
JPB	85	Pease Blvd Regulator Station - Distribution Tie In	$ -	$ -	$ 258.24	$ -	$ -
JPB	87	Mill Road-Durham Station Rebuild	$ -	$ -	$ -	$ 770.70	$ -
JPB	88	Mill Road Station Durham Distribution Tie In	$ -	$ -	$ -	$ 131.88	$ -
JPB	89	New Heater Installation - Ocean Road Station	$ -	$ -	$ -	$ 2,615.99	$ -
JPB	90	Pressure Regulation Training Assembly w/Flaring capability	$ -	$ -	$ -	$ 330.98	$ -
JPB	91	Exeter Hampton 171 PSIG Improvement Phase 1	$ -	$ -	$ -	$ 2,952.87	$ -
JPB	92	Exeter Hampton 171 psig Replacement Phase 2	$ -	$ -	$ -	$ -	$ 1,810.52
JPB	93	Barberry Lane Regulator Station Upgrade-Phase I	$ -	$ -	$ -	$ -	$ 1,299.19
JPB	94	Seabrook / Dog Track Station Distribution Tie In	$ -	$ -	$ -	$ -	$ 73.85
JPB	95	Hampton IP System Improvement	$ -	$ -	$ -	$ -	$ 440.79
JPB	96	Seabrook Dog Track Station Replacement	$ -	$ -	$ -	$ -	$ 1,337.71
JPB	97	Exeter Road Station Rebuild-Phase I	$ -	$ -	$ -	$ -	$ 1,493.48
JPC	1	Hawthorne/Applevale Stations Rebuild-PHASE 1	$ 352.89	$ -	$ -	$ -	$ -
		Sub-Totals:	$ 12,598.41	$ 10,518.24	$ 9,221.63	$ 11,915.59	$ 12,355.68

Distribution Projects exceeding $200,000:

- Mains Extensions – includes installation of mains to reach new customers. Individual projects in excess of $40,000 require an individual authorization. The estimate for this project is derived from historical spending in addition to known projects with a slight increase in the cost of labor, contract services, and materials.

- Gas Highway Projects – includes the relocation of gas facilities due to encroachments and forced diversions as a result of city and state roadway projects. The estimate for this project is derived from historical spending along with known projects with a slight increase in the cost of labor, contract services, and materials.

- Asphalt Restoration – includes the final pavement associated with distribution projects from the prior year. All distribution projects within municipal streets require asphalt restoration according to local specifications. This budget item captures all paving costs for distribution projects over that multi-year time frame. The estimate for this project is derived from historical spending along with known projects with a slight increase in the cost of labor, contract services, and materials.

- Farm Tap Replacements – includes the replacement of buried farm tap regulators that may be susceptible to corrosion. This budget estimate is based upon the quantity of farm taps estimated for replacement in a given year (typically 25 to 30).

- Regulator Station OPP/Redundancy – includes the retrofit of existing regulator stations with overpressure protection (“OPP”) valves (Becker Super Monitors with fire valves or relief valves). Each individual station’s configuration dictates the work required, with the cost of this work impacting how many installations can be completed per year. The installation of OPP devices is an enhancement to Unitil's overall OPP strategy and acts as a tertiary level of system over-pressure protection, adding an additional level of over-all safety to the public as well as enhancing continuity of service. This budget estimate is based upon the quantity of retrofits estimated in a given year.

- Hawthorne/Applevale Station Rebuild and Distribution Tie-in – includes the complete rebuild of both the Hawthorne Avenue and Applevale Road regulator stations in Dover, NH, including the installation of pre-heat, as well as designing the stations to accommodate increased load on the systems that they both serve. Hawthorne Avenue station is installed in vaults and experiences a significant amount of icing. The station must be brought above ground to facilitate the installation of a gas pre-heat system to alleviate the icing condition. Understanding that space is at a premium at this location the decision was made to combine both stations into one site. The budget estimate was based upon the actual design of the station.

- Salem Gate Station Meter and Bypass Run Upgrade – includes replacing Kinder Morgan's exiting meter with one that can flow at the new demand level of the downstream Salem IP system and rebuild the meter by-pass run so that it can accommodate over-flow from the primary meter during times of high flow or in the event of a meter failure on the primary run. The existing upstream meter is undersized and has significantly compromised performance during times of high demand. These performance issues put the operational integrity of the downstream Salem IP system in jeopardy and on several occasions has completely interrupted the gas flow to a point that emergency actions needed to be initiated so as to not lose the Salem IP system. This new meter and piping configuration will prevent this issue from re-occurring and increase the operational robustness of the Salem IP system. The budget estimate was based upon the actual design.

- Water Street Exeter Main Replacement – includes the replace approximately 700 feet of 4" coated steel main on Water St in Exeter, NH from Green Street to Main St with disbonded coating and tie over three impacted services. The coating on the existing 4" coated steel main on Water St near Green St was found to be disbonding, creating a risk for cathodic protection. The main was tested and found to have sufficient cathodic protection but will need to be replaced due to insufficient coating. The budget estimate was based upon the actual design.

- Blackwater Rd Somersworth Improvement – includes the installation of approximately 6800' of 8" HDPE main on Blackwater Rd from High Street to Route 108 in Somersworth, NH. The purpose of this project is to improve pressures and reliability in the Somersworth IP system. This estimate includes time and materials to complete the job as well as four short, full-width mill and pave sections and two horizontal directional drills. This project will be completed in two phases. The budget estimate was based upon the actual design.

- Bartlett Avenue/High Street Stations Rebuild and Distribution Tie-In – includes the complete re-build of both the 150 PSIG High Line Station & 50 PSIG Somersworth Station in Somersworth, NH into one combined new station that will serve Rochester, Dover and Somersworth as well as the distribution tie-in to the existing system. Once completed, the existing Bartlett Avenue Station will be decommissioned. This new station is required to serve increased load in all three systems and will include the addition of pre-heat to mitigate gas heating concerns. In addition, the new proposed location mitigates the need to install additional overpressure protection requirements at both existing stations as well as undertake other station system improvements. The budget estimate was based upon the actual design.

- Nimble Hill Station Replacement and Distribution Tie-in - includes the fabrication of a new district regulator station within the same geographical location as the existing Nimble Hill Road in Newington, NH. This station will be supplied directly from the GSGT-492 PSIG and will operate at a 56PSIG MAOP. This new station is an upgrade to the existing facility and will be located to minimize safety risk associated with the heavy Spaulding Turnpike traffic. This estimate is based on pricing for regulator station projects in both ME & NH and also includes updated cost associated with the installation of additional levels of overpressure protection.

- Route 151 System Merger – includes the installation of a new main on Route 151 in Greenland, NH. The project scope includes installing 2000 feet of 4” HDPE main along the NHDOT ROW on Route 151 (Post Rd). This main extension will connect the Route 151 system (System 415, 56 PSIG MAOP) to the Portsmouth IP system (System 417, 56 PSIG MAOP). This project must be completed to allow for the retirement of the Route 151 M&R station, avoiding extensive capital expenditure of approximately $1,200,000 for designing, rebuilding, and relocating the station. The budget estimate was based upon the actual design.

- Pease Boulevard New Regulator Station and Distribution Tie-in – includes the complete replacement of the Gosling Rd regulator station and NH Avenue Station and the tie-in to the existing distribution system. The existing station is a primary feed to the Portsmouth IP system and has only a single regulator run. A new station with primary and secondary runs will provide redundancy and reduce the possibility of underpressure in the Portsmouth IP system in the event of a regulator failure. Gas preheat will prevent regulator freezing that could cause a system overpressure condition. The budget estimate was based upon the actual design.

- Mill Road Durham Station Rebuild and Distribution Tie-in – includes the complete re-build of the Mill Road station in a new location located along Mill Road in Durham, NH and the tie-in to the existing distribution system. Station to include all required levels of overpressure protection and operate to supply the same capacity as the current Mill Road Station. Once completed, the existing Mill Road Station vaults will be decommissioned. This new station is required as the current station poses operational concerns due to its geographic location. Although mitigation measures have been installed, the station is still prone to flooding and its location in a sidewalk-located next to the UNH campus makes it impossible to appropriately swale the water. In addition, the buried sense lines at this location are in immediate need of replacement which will require significant excavation and station reconfiguration. Combining the costs of the sense line relocation with the operational difficulties at this station warrants a relocation so that the station can be installed above ground and incorporate necessary additional OPP to ensure operational integrity and customer safety. The budget estimate was based upon the similar projects.

- Heater Installation – Ocean Road Station – includes the installation of a new indirect gas fired pre-heater at the Ocean Road Station-Portsmouth IP. As part of the 2020 Engineering Regulator, Meter and Heat capacity reporting it was determined that this station would require an indirect fired gas preheater within the next 3-5 years due to growth in the Portsmouth IP system. The budget estimate was based upon similar projects.

- Pressure Regulation Training Assembly w/Flaring capability – includes the construction of a pressure regulation training & testing assembly with flaring capability. This assembly includes piping, valving, filtration and multiple pressure regulation devices (Mooney, Grove, Fisher, etc.) and has the capability to operate on natural gas and nitrogen. As part of the new requirement associated with practical exams being required for all Operator Qualification tasks, including those that are related to pressure regulation, this new device will allow for technicians to perform practical application of as it related to the maintenance and operation of pressure regulation assemblies that simulate pressure regulation facilities and large volume meters. This budget estimate is based upon a similar design.

- Exeter Hampton 171 PSIG Improvement – includes 1) Phase 1 - the paralleling of an existing 6-inch, coated-steel main with a new 12-inch, coated-steel main extending for approximately 2,525 feet from 691 Exeter Road to 611 Exeter Road (NH-27) in Hampton, New Hampshire and 2) Phase 2 - the paralleling of an existing 6-inch, coated-steel main with a new 12-inch, coated-steel main extending for approximately 2,450 feet from 255 Exeter Road to 179 Exeter Road (NH-27) in Hampton, New Hampshire. The Exeter-Hampton HP system provides gas supply into NH Systems #09 (Exeter IP) and #14 (Hampton IP). Although the Exeter IP system is located near the GSGT line, the Hampton IP system receives gas solely from NH System #08. The inlet for the NH System #08 is over 6-miles (approximately 36,000 feet) away from the GSGT meter and regulator station. The Hampton IP system has experienced continued growth. There is a risk that the existing main will be undersized if continued growth at a similar rate. The consequence of an undersized main would be inadequate gas volume to support existing and new customers. The budget estimate is based upon similar projects.

- Barberry Lane Regulator Station Upgrade-Phase I – includes upsizing station piping to 4" and while station piping is being fabricated, install new Dollinger filter, regulators and replace valves that are currently getting increasing difficult to maintain. In addition, install new indirect fired water bath pre-heater to prevent substantial icing due to increased flow through this station. This cost reflects updates based on real pricing for regulator station projects in both ME & NH and also includes updated cost associated with the installation of additional levels of OPP not included in the initial proposal. Based on Gas Engineering growth projections, the capacity increase through this station will require larger piping and regulators.

- Hampton IP System Improvement – includes the replacement of 1,500 feet of 4” plastic main with new, 6” IPS HDPE main on High St. The proposed system improvement has been designed to prevent low pressure incidents in the Hampton IP system (NH-System 14, MAOP 45 PSIG). The Hampton IP system is a single-feed system supplied by the Exeter Rd district regulator station. The trends from our customer usage data seem to indicate that the number year-round residents in the Hampton Beach area is growing year-over-year, which has increasingly put strain on the Exeter Rd station and has depleted pressures at the end of the Hampton IP system. Without some form of system improvement, the low-pressure incidents in the Hampton IP system will persist, and as an increasing number of residents chose to remain in Hampton during the winter season, the low-pressure issues will only continue to worsen in heating seasons moving forward. This budget estimate is based upon similar projects.

- Seabrook Dog Track Station Replacement – includes the fabrication of a new district regulator station within the same geographical location as the existing Dog Track Station in Seabrook, NH. This station will be supplied directly from the East Kingston high line-125 PSIG and will operate at a 56PSIG MAOP. This new station is an upgrade to the existing facility and will be located to minimize safety risk associated with the heavy Route 107 in Seabrook and deal with roadway drainage issues-draining into the pit. This budget estimate is based upon previous mini district regulator station installations.

- Exeter Road Station Rebuild – includes the fabrication of a new district regulator station within the same geographical location as the existing station. This new station is an upgrade to the existing facility and will be located to minimize safety risk associated traffic in the area. This estimate is based on real pricing for regulator station projects in both ME & NH and also includes updated cost associated with the installation of additional levels of OPP. This budget estimate is based upon similar projects.

6. Tools, Shop, Garage

These are individually authorized tools and equipment designed to assist with the safe installation and maintenance of the gas distribution system and regulator stations. There are no projects that exceed $200,000.

Table IV-7: Forecast Tools, Shop, Garage Spending ($000's)

Budget Code	Budget #	Tools, Shop, Garage:Gas	2023	2024	2025	2026	2027
EAG	1	Tools: Normal Additions and Replacements - Systems Operations	$ 24.00	$ -	$ -	$ -	$ -
EAG	1	Tools: Normal Additions and Replacements - Systems Operations	$ -	$ 25.00	$ -	$ -	$ -
EAG	1	Tools: Normal Additions and Replacements - Systems Operations	$ -	$ -	$ 18.00	$ -	$ -
EAG	1	Tools: Normal Additions and Replacements - Systems Operations	$ -	$ -	$ -	$ 18.00	$ -
EAG	1	Tools: Normal Additions and Replacements - Systems Operations	$ -	$ -	$ -	$ -	$ 18.00
EAG	2	Tools: Normal Additions and Replacements	$ 35.54	$ -	$ -	$ -	$ -
EAG	2	Tools: Normal Additions and Replacements	$ -	$ 36.60	$ -	$ -	$ -
EAG	2	Tools: Normal Additions and Replacements	$ -	$ -	$ 37.70	$ -	$ -
EAG	2	Tools: Normal Additions and Replacements	$ -	$ -	$ -	$ 38.83	$ -
EAG	2	Tools: Normal Additions and Replacements	$ -	$ -	$ -	$ -	$ 40.00
EAG	5	Normal add & replace- tools & equipment - Metering and FS	$ 5.05	$ -	$ -	$ -	$ -
EAG	5	Normal add & replace- tools & equipment - Metering and FS	$ -	$ 5.05	$ -	$ -	$ -
EAG	5	Normal add & replace- tools & equipment - Metering and FS	$ -	$ -	$ 5.05	$ -	$ -
EAG	5	Normal add & replace- tools & equipment - Metering and FS	$ -	$ -	$ -	$ 5.05	$ -
EAG	5	Normal add & replace- tools & equipment - Metering and FS	$ -	$ -	$ -	$ -	$ 5.05
EAG	6	Pipeline Safety Management System	$ 25.00	$ -	$ -	$ -	$ -
EAG	6	Pipeline Safety Management System	$ -	$ 30.00	$ -	$ -	$ -
EAG	6	Pipeline Safety Management System	$ -	$ -	$ 30.00	$ -	$ -
EAG	6	Pipeline Safety Management System	$ -	$ -	$ -	$ 30.00	$ -
EAG	6	Pipeline Safety Management System	$ -	$ -	$ -	$ -	$ 30.00
EAG	7	Training Equipment/Materials	$ 25.00	$ -	$ -	$ -	$ -
EAG	7	Training Equipment/Materials	$ -	$ 25.00	$ -	$ -	$ -
EAG	7	Training Equipment/Materials	$ -	$ -	$ 25.00	$ -	$ -
EAG	7	Training Equipment/Materials	$ -	$ -	$ -	$ 25.00	$ -
EAG	7	Training Equipment/Materials	$ -	$ -	$ -	$ -	$ 25.00
EAG	12	Vacuum Excavation Trailer	$ 105.17	$ -	$ -	$ -	$ -
EAG	13	Mobile Survey Gas Detector Replacement	$ 26.00	$ -	$ -	$ -	$ -
EAG	22	Mueller Equipment	$ -	$ 110.00	$ -	$ -	$ -
EAC	1	DIMP Risk Model Carryover	$ 50.00	$ -	$ -	$ -	$ -
EAC	1	DIMP Risk Model Carryover	$ -	$ 41.67	$ -	$ -	$ -
EAC	1	DIMP Risk Model Carryover	$ -	$ -	$ 41.67	$ -	$ -
EAC	1	DIMP Risk Model Carryover	$ -	$ -	$ -	$ 41.67	$ -
EAC	2	GIS Data Development - Services & Station Utilities - CarryOver	$ 84.00	$ -	$ -	$ -	$ -
		Sub-Totals:	$ 379.76	$ 273.32	$ 157.42	$ 158.55	$ 118.05

7. Office

These projects are for the routine purchase and replacement of furniture and equipment within the Portsmouth office location. There are no projects that exceed $200,000.

Table IV-8: Forecast Office Spending ($000's)

Budget Code	Budget #	Office:Gas	2023	2024	2025	2026	2027
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	$ 5.00	$ -	$ -	$ -	$ -
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	$ -	$ 5.00	$ -	$ -	$ -
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	$ -	$ -	$ 5.00	$ -	$ -
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	$ -	$ -	$ -	$ 5.00	$ -
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	$ -	$ -	$ -	$ -	$ 5.00
		Sub-Totals:	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00

8. Structures

These projects are individually authorized projects to address replacements and additions with respect to the office building structures.

Table IV-9: Forecast Structures Spending ($000's)

Budget Code	Budget #	Structures:General	2023	2024	2025	2026	2027
GPB	1	Normal Improvements to Portsmouth Facility	$ 18.00	$ -	$ -	$ -	$ -
GPB	1	Normal Improvements to Portsmouth Facility	$ -	$ 20.00	$ -	$ -	$ -
GPB	1	Normal Improvements to Portsmouth Facility	$ -	$ -	$ 20.00	$ -	$ -
GPB	1	Normal Improvements to Portsmouth Facility	$ -	$ -	$ -	$ 25.00	$ -
GPB	1	Normal Improvements to Portsmouth Facility	$ -	$ -	$ -	$ -	$ 25.00
GPB	2	Building Improvements	$ -	$ 300.00	$ -	$ -	$ -
GPB	2	Building Improvements	$ -	$ -	$ -	$ 300.00	$ -
GPB	2	Building Improvements	$ -	$ -	$ -	$ -	$ 300.00
GPB	25	Upgrade Office & General Lighting	$ 50.00	$ -	$ -	$ -	$ -
GPB	31	Restroom Upgrades	$ -	$ 150.00	$ -	$ -	$ -
GPB	32	Carpet Replacement	$ -	$ 150.00	$ -	$ -	$ -
GPB	33	Interior Walls Improvements	$ -	$ 30.00	$ -	$ -	$ -
GPB	37	High Efficiency Cooling - Stock Room	$ -	$ 20.00	$ -	$ -	$ -
GPB	40	Construct Unitil Operations Training Facility - Carryover	$ -	$ 500.00	$ -	$ -	$ -
GPB	40	BMS - HVAC & Lighting	$ -	$ -	$ 200.00	$ -	$ -
GPB	41	Site Improvements	$ -	$ -	$ 350.00	$ -	$ -
GPB	42	Room-by-room zone control system	$ -	$ -	$ 30.00	$ -	$ -
GPB	43	Construct Unitil Operations Training Facility - Carryover	$ -	$ -	$ 500.00	$ -	$ -
GPB	61	UPS Replacement	$ -	$ -	$ -	$ 80.00	$ -
GPB	62	HVAC Upgrades	$ -	$ -	$ -	$ 1,000.00	$ -
GPB	63	Construct Unitil Operations Training Facility - Carryover	$ -	$ -	$ -	$ 750.00	$ -
GPB	70	Replace HVAC System w/Heat Pump Unit	$ -	$ -	$ -	$ -	$ 100.00
GPB	71	Heat Pump Water Heater	$ -	$ -	$ -	$ -	$ 10.00
GPB	72	Solar PV installation	$ -	$ -	$ -	$ -	$ 420.00
		Sub-Totals:	$ 68.00	$ 1,170.00	$ 1,100.00	$ 2,155.00	$ 855.00

Structure Projects exceeding $200,000:

- Building Improvements – includes the unscheduled building improvements to address aging equipment and other efficiency projects. Projects will be reviewed and identified in subsequent years prior to completing the projects. This estimate is based upon historical spending. Projects will be specified in subsequent budget years.

- Operations Training Facility – includes a multi-year project to construct a hands-on gas training facility. 49 CFR §192 Subpart N Qualification of Pipeline Personnel ("Operator Qualification" or "OQ") requires that personnel that operate, maintain, or perform construction activities on a pipeline facility be trained and qualified. Unitil has assisted in the development and has adopted the Northeast Gas Associations ("NGA") regional operator qualification program as our OQ platform. The NGA OQ program consists of (87) covered tasks that have training and qualification requirements on (1) and (3) year intervals. In addition, Unitil has an additional (7) Company-specific tasks that are unique to our distribution system. Historically, qualification protocols consisted of both knowledge and skill tests depending on the complexity of the task. The knowledge tests consist of written exams administered electronically and comprise approximately 85% of the current identified tasks. In addition to the knowledge exams, about 15% of the tasks also have a hands-on skills test conducted with a proctor in a simulated environment. In the aftermath of Merrimack Valley, state regulators have communicated concerns with the current configuration of knowledge tests versus skill tests. Rulemaking has been initiated in several states to address these concerns, with more to follow over the next few years. In response, the NGA OQ Committee has completed a full evaluation of the current program. This committee has recommended that additional hands-on skill tests be implemented to implement the vast majority of all covered tasks (approx. 75 tasks) over three years (2022-2024). These skill tests require the construction of prescriptive simulated mock-ups of system components for skill testing in a simulated environment. In addition to the qualification requirements, there is also a renewed regulatory emphasis on the formal training for our pipeline personnel. OQ qualification is the last step in the process, and a formal structured and robust training program is an essential component of the qualification process. Historically, we have relied upon system deficiencies to provide training opportunities to our pipeline technicians in the field (e.g., gas leaks). However, over time our distribution system has become more robust, and these real-world training opportunities have been reduced. This trend will continue, and these real-world training opportunities must transition into a simulated environment that would also be included in this training facility. A well-trained and qualified workforce is not only a regulatory requirement but essential for ensuring public safety. Pipeline safety incidents caused by human error are preventable when technicians are trained and qualified. With all the changes to operator qualification and training, a facility or another solution is required to ensure a qualified workforce.

- Site Improvements – includes the unscheduled site improvements. Projects will be reviewed and identified in subsequent years prior to completing the projects. This estimate is based upon historical spending.

- Solar PV Installation – includes installing solar PV on the rooftop of the building. This project was identified in a recent building energy assessment. This project will be reviewed over the next few years to develop a business plan.

9. Economic Impacts

The Working Group Report submitted to the Commission included a recommendation ("Recommendation 5") that Northern "[a]ssess economic development impacts by estimating direct, indirect, and induced jobs created from a resource and the associated economic development impact."[76] Addressing this recommendation, the Commission stated: "We agree that Northern should assess the economic impacts of its distribution system operation and its system upgrades by reporting on direct jobs attributable to Northern's operations over the last 20 years."[77] Northern notes that the Commission's conclusion does not align with the Working Group's recommendation. The Commission indicated that it would not require Northern to conduct an economic analysis or develop a complex model, and would "accept such analysis as is available from the US Department of Labor or other governmental resources."[78] As it pertains to the Company's distribution system operation and system upgrades over the last 20 years, Northern has not, as of this writing, identified a governmental source to accurately report on direct jobs attributable to Northern's operations over the last 20 years.

[76] DG 19-126, Order No. 26,664 at 10.
[77] Id. at 15.
[78] Id.

V. Demand Forecast

Key Takeaways

Key takeaways in this chapter include the following:

- *The Company's projection of growth in annual throughput under normal weather for the five year planning period is 1.2%, which is down from 1.5% observed over the prior five years. The Company's demand forecast is built at the Customer Segment level, with separate regression models for number of customers and use per customer, adjustments for expected energy efficiency savings, Company Use and Lost and Unaccounted for Gas.*
- *Energy Efficiency savings are expected to reduce forecasted throughput under normal weather by approximately 1 Bcf over the five year planning period, reducing the throughput forecast in the Maine Division from 2.3% to 1.9% and in the New Hampshire Division from 0.7% to 0.3%.*
- *The Company continues to use a 30 year weather history to perform weather adjustment calculations. Average temperatures observed in the Maine Division have declined steadily since the 1960s, however the pace of warming appears to be increasing.*

A. Introduction

The forecast of firm customer demand and the subsequent determination of planning load requirements over the planning horizon are integral parts of the development of Northern's IRP that serve as the basis for resource decision making. Section IV of this IRP describes the forecast methodology and assumptions, reviews the development and results of Customer Segment forecasts and expected energy efficiency savings, then presents the normal year throughput forecast over the five-year planning horizon covering the gas years of 2022/23 through 2026/27.[79]

Section V, Planning Load Forecast, documents the development of the design year and design day throughput forecasts, and the reduction for capacity exempt demand from the throughput forecasts to yield planning load requirements.

This Demand Forecast section is organized as follows:

Part B, Forecast Methodology and Summary Results, provides an overview of the forecasting process and presents Northern's system-wide (Maine and New Hampshire) customer and Normal Year Throughput forecast results;

[79] A gas-year is defined as the twelve-month period from November to October; with the winter period defined as the five months from November to March, and the summer period defined as the seven months from April to October.

Part C, Customer Segment Forecasts, describes the forecasting methodology, data utilized, including an analysis of climate change trends, discussion of key drivers in the forecast models chosen, normal weather demand results and adjustments for energy efficiency for each Customer Segment;

Part D, Normal Year Throughput Forecast, describes the calculation of the Normal Year Throughput forecast and presents projected Normal Year Throughput for each division;

Part E, Energy Efficiency Impact on Forecast, shows how much higher the Normal Year Throughput forecast would be without projected energy efficiency savings.

Complete detail on the statistical modeling process, statistical output from all Customer Segment models and comprehensive documentation of the demand forecast is provided in Appendix 1, Supplemental Materials for the Demand Forecast Section.

B. Forecast Methodology and Summary Results

The long-term natural gas demand models that were developed for the 2022/23 through 2026/27 demand forecast use variables that reflect the major factors that influence natural gas demand in the Company's service territory. This section includes a description of the demand forecasting methodology, models, and Company-wide results.

This IRP uses the definitions listed in Table V-1 below to refer to and distinguish between different types of natural gas demand. There are no distinctions made between Sales Service and Transportation Service demands in the development of the Customer Segment demand models and the calculation of Normal Year Throughput.

Table V-1: Forecast Terminology[80]

Term	Definition
Demand, Usage, or Load	Generic terms that refer to the gas consumed by customers
Sales Demand	Demand of "Sales Service" customers who purchase gas from the Company
Transportation Demand	Demand of C&I "Transportation Service" customers who purchase gas from a retail marketer under the Delivery Service Terms and Conditions
Customer Segment Demand	Aggregate demand of a defined group of customer classes measured at the customer meter on a billing period basis, generally reported in Therms
Throughput (TPUT)	Aggregate usage measured at the gate station or production of on-system gas on a calendar period basis, including Demand, Company Use and Lost and Unaccounted For Gas, generally reported in Dth

80 These definitions refer to firm service; Northern does not have any interruptible customers at this time.

Separate sets of forecasts were developed for Northern's Maine and New Hampshire Divisions using the same processes and, to the extent possible, the same regression model specifications and then combined to establish Northern's system-wide demand. For each Division, the demand forecasts were developed at the Customer Segment level under normal weather conditions based on economic and demographic data that incorporate the major factors influencing natural gas demand in the Company's service territory, as described in more detail in the following section. Modeled Customer Segment Demand was reduced for incremental savings expected from energy efficiency programs to yield expected net demand.[81] The Company made no explicit out of model adjustments, such as for marketing efforts. Customer net demand from each segment was tallied and adjusted further for Company Use and lost and unaccounted for gas to estimate Normal Year Throughput, which is total usage at the Company's gate stations on a calendar month basis under normal weather conditions.

As shown in Table V-2, which reflects both the Maine Division and the New Hampshire Division, Northern's customer count is projected to increase at an average annual rate of 1.7% which reflects the addition of approximately 6,000 customers over the forecast period, which is consistent with prior results.

Table V-2: Northern Projected Customer Counts

Gas Year	Residential Customers	C&I LLF Customers	C&I HLF Customers	Company Customers
2017/18	49,025	13,767	2,247	65,039
2018/19	50,276	13,810	2,312	66,398
2019/20	51,652	13,899	2,295	67,847
2020/21	52,701	14,040	2,296	69,038
2021/22	53,463	14,191	2,313	69,967
CAGR	2.2%	0.8%	0.7%	1.8%
Gas Year	Residential Customers	C&I LLF Customers	C&I HLF Customers	Company Customers
2022/23	54,451	14,345	2,321	71,117
2023/24	55,549	14,474	2,324	72,347
2024/25	56,612	14,620	2,328	73,560
2025/26	57,681	14,773	2,332	74,787
2026/27	58,748	14,920	2,336	76,004
CAGR	1.9%	1.0%	0.2%	1.7%

Table V-3 presents the forecast of Northern's Normal Year Throughput. Normal Year Throughput is calculated as the sum of Customer Segment demand net of incremental energy efficiency savings, which

81 Expected energy efficiency savings are expected reductions in customer demand associated with current energy efficiency programs and budget levels, extrapolated through the forecast period. Energy efficiency programs are funded through charges to Northern's natural gas customers.

is developed in therms on a billing cycle (BC) basis then converted to Dth on a calendar (Cal) basis, plus Company use and lost and unaccounted for gas. Normal Year Throughput is projected to increase at an average annual rate of about 1.2%, resulting in approximately 1.1 Bcf of additional annual throughput by the end of the five year planning horizon.

Table V-3: Northern Normal Year Throughput (Dth)

Gas Year	Company Net Demand (Th)	Company Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2017/18	192,803,990	19,285,161	12,371	211,526	19,509,059
2018/19	199,747,922	19,986,866	12,437	219,260	20,218,563
2019/20	195,957,703	19,622,757	11,761	215,951	19,850,468
2020/21	199,580,628	19,900,175	11,654	218,810	20,130,640
2021/22	204,260,195	20,431,665	11,636	224,565	20,667,866
CAGR	1.5%	1.5%	-1.5%	1.5%	1.5%
Gas Year	Company Net Demand (Th)	Company Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2022/23	210,448,750	21,068,168	11,566	231,361	21,311,096
2023/24	212,878,602	21,302,734	11,890	234,396	21,549,021
2024/25	215,727,407	21,587,819	11,890	237,654	21,837,364
2025/26	218,360,117	21,851,669	11,890	240,722	22,104,281
2026/27	220,826,674	22,098,478	11,890	243,624	22,353,992
CAGR	1.2%	1.2%	0.7%	1.3%	1.2%

C. Customer Segment Forecasts

1. Introduction

The Customer Segment forecasts are based on forecasts of economic and demographic conditions in the Company's Maine and New Hampshire service territories. The Customer Segment forecast was derived from separate Division-specific monthly forecast models for each of the following Customer Segments:

- Residential Customers
- C&I Low Load Factor ("LLF")[82] Total Customers (i.e., Sales and Transportation)
- C&I High Load Factor ("HLF") Total Customers (i.e., Sales and Transportation)

[82] In Maine, LLF (or equivalently high winter) use is defined as peak period (November through April) usage greater than or equal to 63% of annual usage. In New Hampshire, LLF (or equivalently high winter) use is defined as peak period usage greater than or equal to 67% of annual usage. See also Table V-4.

The demand forecasts for the three Residential and C&I Customer Segments are based on separate econometric models for number of customers and use per customer. Thus, in total, six separate Residential and C&I models were developed for each Division. Currently, there are no Special Contract customers in the Maine Division and there are two Special Contract customers in the New Hampshire Division, which were included in the New Hampshire C&I High Load Factor Customer Segment. The demand forecast for each Customer Segment was determined by multiplying the forecasted results from the number of customer model by the forecasted results from the use per customer model.

The Customer Segment demand forecast models were developed using regression analysis, based on accepted statistical techniques.[83] For the Customer Segment forecasts, regression analysis on monthly frequency data was used to predict monthly number of customers and use per customer by Customer Segment based on predicted values of various external variables (e.g., weather, employment levels, gross metropolitan product, households, household size, average household income, employment in manufacturing, time based variables, and population). In regression analysis the number of customers and the use per customer are the dependent variables and the external variables (regressors) are the independent variables. The Customer Segment dependent variables for each Division were based on historical billing data. The Customer Segment models were estimated using dependent variable and independent variable data from January 2016 through December 2022.

All regression analysis was conducted using *EViews* a statistical software package. The Statistical Techniques and Glossary section of Appendix 1 provides a full description of the modeling process used to develop the regression models, and also includes all outputs for the regression models and statistical tests conducted.

2. Data Description

Five general data and variable categories were used in the development of the Customer Segment forecasts; these categories are described below. The actual variables used in each Customer Segment regression model are defined along with each model.

a) Customer Segment Data

Historical monthly billing data were collected from Company records for each Division by customer class for the period January 2016 through December 2022, including demand, measured in therms and number of customers by rate class for each Division. This data was aggregated into the respective Customer Segments by combining customer classes with similar usage patterns. For example, the C&I Low Load Factor Customer Segment is comprised of C&I customers that are served under one of Northern's high winter use rate schedules, whereas the C&I High Load Factor Customer Segment is

83 Regression analysis is concerned with relating a dependent (or response) variable with a set of independent (or predictor) variables; a common use of regression analysis is to allow for predictions of the dependent variable based on predicted values of the independent variables.

comprised of C&I customers that are served under one of Northern's low winter use rate schedules. The customer classes that comprise each Customer Segment for each Division are shown in the table below:

Table V-4: Customer Segment Definitions

Class ME	Class NH	Class Description	Customer Segment
R-2	R-5, R-10	Residential Heating	Residential
R-1	R-6, R-11	Residential Non-Heating	
G-40	G-40	C&I Low Annual Use, High Peak Period/ Winter Use	C&I Low Load Factor (LLF)
G-41	G-41	C&I Medium Annual Use, High Peak Period/ Winter Use	
G-42	G-42	C&I High Annual Use, High Peak Period/ Winter Use	
G-50	G-50	C&I Low Annual Use, Low Peak Period/ Winter Use	C&I High Load Factor (HLF)
G-51	G-51	C&I Medium Annual Use, Low Peak Period/ Winter Use	
G-52	G-52	C&I High Annual Use, Low Peak Period/ Winter Use	

Weather Variables

Historical daily effective degree day ("EDD") data for the 30 year historical period of November 1, 1991 through October 31, 2021 was utilized by the Company for the Maine Division (measured at the Portland, Maine weather station PWM) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station PSM). Daily EDD data were calculated based on averages of 24 hours of temperature and wind speed data for each Gas Day, which begins and ends at 10 AM each day.[84]

Firm natural gas demand is heavily dependent on weather conditions, as measured by EDD, which vary on a daily, monthly, and annual basis. Customer segment demand is measured on a billing month basis whereby approximately equal numbers of Northern's customer meters are read in cycles every working day of the month. As a result, most of the consumption recorded in the first billing cycles of a billing month relates to consumption that occurred in the prior calendar month, and most of the consumption recorded in the last billing cycles of a billing month relates to consumption that occurred in the same calendar month. Thus, consumption in each billing month is affected by EDD observed in both the same month and the prior month. A billing month EDD variable was developed to align the pattern of observed daily EDD to the billing cycle pattern each month. The methodology used to calculate billing

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[84] The Company used the average temperature and wind speeds to produce daily EDD for each Gas Day for each Division according to the following formula:

*If avg. temperature < 65, EDD = (65 – avg. temperature) * (1 + (avg. wind speed / 100))*

If avg. temperature > 65, EDD = 0

cycle monthly EDD data is illustrated in the "Calculation of Billing Cycle EDD Variable" section of Appendix 1.

Historical billing cycle monthly EDD values for the period November 2014 through March 2019 were calculated and used to measure the effect of temperature on natural gas use in the Customer Segment use per customer regression models.[85] Historical EDD values were also used to develop normal year and design year EDD patterns, as well as design day EDD levels, for each Division. The normal year EDD pattern was used to restate historical period usage by Customer Segment for assessment purposes. The normal year and design year EDD patterns were applied to the Customer Segment models to estimate normal year and design year demand. These EDD patterns are described further and presented in Section V, Planning Load Forecast.

b) Climate Change Analysis

The Company looked at climate change in terms of whether long-term trends in the statistical distribution of weather patterns are impacting the predictive power of historical weather data depending on the length of history used. A statistical analysis was prepared for this IRP to determine whether there is a difference in the ability of distributions comprised of 10, 20, or 30 years of historical EDD data to predict the weather (EDD) in the next year, and if so, which was the best predictor. If climate change is trending significantly, then the 10 year distribution may be a better predictor as it is based on a shorter period more reflective of recent experience; whereas, if climate change is not trending significantly, then the 30 year distribution may be a better predictor as it includes more history providing more statistical significance for establishing planning standards. To test this hypothesis, rolling 10, 20, and 30 year average EDD were calculated and compared to the EDD for the following year. For example, 10, 20, and 30 year averages were calculated for the year ending 2021/22 and compared with the actual EDD that occurred in 2022/23. This analysis was conducted for all years available.

The predictive capability of each distribution (i.e., rolling average) was determined by comparing the standard error associated with each rolling average. The standard error (or, root mean square error ("RMSE")) measures the average error between the rolling average and the actual EDD. The lowest standard error determines the best predictor of the next year's EDD. Analyses of 10, 20, and 30 year standard errors were prepared using annual (gas year) EDD, winter (November to March) EDD, January EDD, and Max Daily EDD. Results are presented in Table V-5 below.

85 The dependent variable in these use per customer models was actual (rather than weather normalized) use per customer.

Table V-5: Climate Change Analysis – By Division

Maine Results- Most Recent 30 Gas Years

	Standard Error (RSME)			% Improvement over 30 Year	
	10 Year Ave	20 Year Ave	30 Year Ave	10 Year Ave	20 Year Ave
Gas Year	460.7	492.4	554.5	16.9%	11.2%
Winter	396.0	401.8	424.9	6.8%	5.4%
January	155.4	157.1	161.0	3.5%	2.4%
Max Daily	6.94	6.88	7.0	1.2%	2.1%

New Hampshire Results- Most Recent 30 Gas Years

	Standard Error (RSME)			% Improvement over 30 Year	
	10 Year Ave	20 Year Ave	30 Year Ave	10 Year Ave	20 Year Ave
Gas Year	477.0	467.0	464.5	-2.7%	-0.5%
Winter	418.0	410.0	404.9	-3.2%	-1.3%
January	165.9	164.4	161.8	-2.6%	-1.6%
Max Daily	6.5	6.4	6.3	-2.6%	-0.4%

The Winter Period (November to March), January, and Max Daily EDDs are increasingly critical periods for resource planning purposes since these are the periods with the greatest consumption levels and consequently the greatest resource constraints. As highlighted above, for the Maine Division, the 10 or 20 year average is a better predictor of the following year EDD than the 30 year average. For the New Hampshire Division, the 10, 20, and 30 year averages are generally good at predicting the following year EDD, with the 30 year average producing slightly better results.

Further analysis was conducted by comparing the average EDD by decade over the previous 6 decades[86] for monthly EDD, Winter (November to March) EDD, Summer (April to October) EDD, Gas Year EDD and Max Daily EDD, as presented in Table V-6 below. The general trend has been declining in average EDD from decade to decade. Winter EDD in New Hampshire saw a significant decline during the past decade (2010's). Average Max Daily EDDs were decreasing from the 1960s, but have begun increasing since the 2000s. Despite the general decrease in annual and winter EDD over time, the rate of change over the most recent three decades spanning the 1990s through the 2010s has been significantly slower than over the preceding three decades spanning the 1960s through the 1980s.

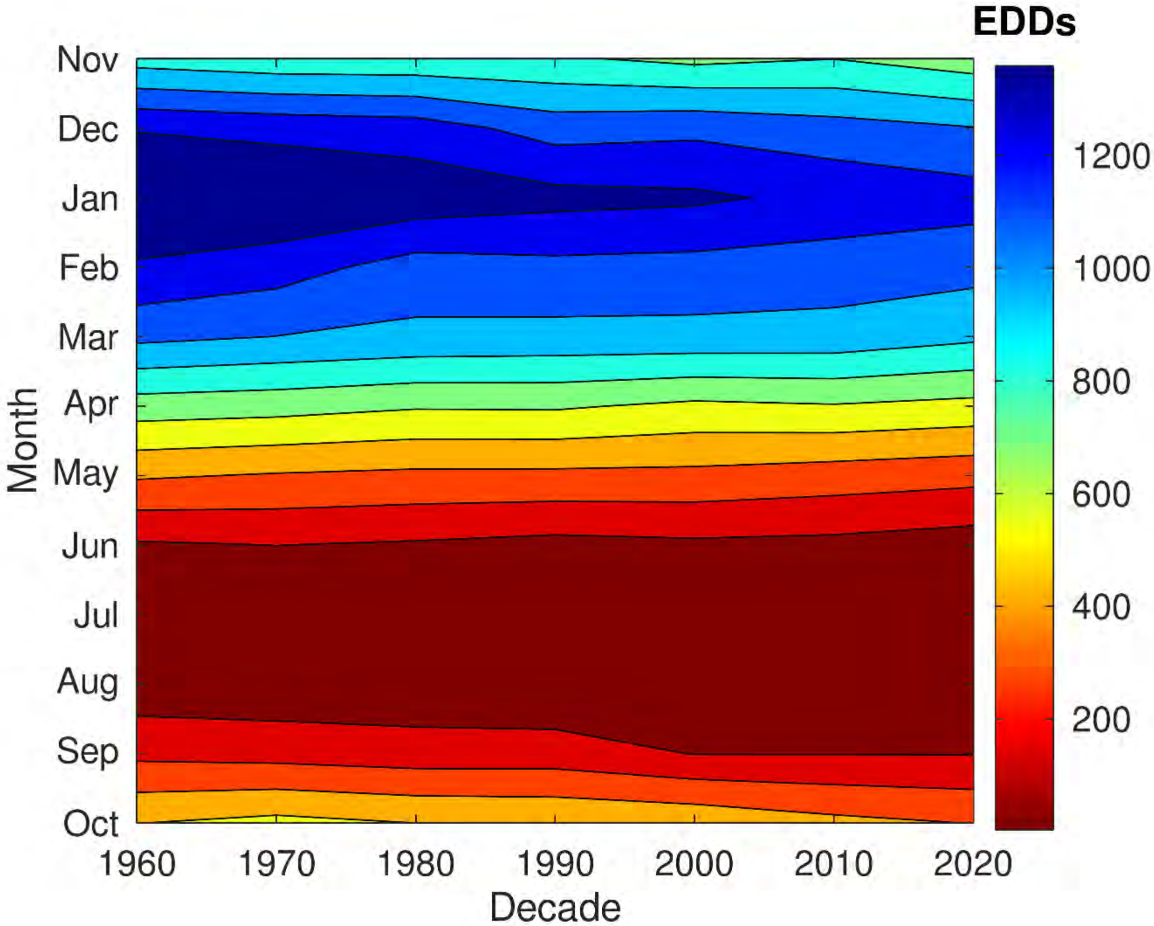
[86] The available data includes 61 gas-years and winters. The data begins November 1961, so the 1960s decade includes only 9 years. Similarly, the data set ends February 2023, so the 2020s decade includes 2 winters and 3 summers.

Table V-6: Average EDD by Decade – By Division

	Maine EDD by Decade							New Hampshire EDD by Decade						
	1960s	1970s	1980s	1990s	2000s	2010s	2020s	1960s	1970s	1980s	1990s	2000s	2010s	2020s
Nov	893	852	848	835	782	815	740	819	769	768	776	744	791	682
Dec	1,352	1,317	1,292	1,166	1,191	1,142	1,095	1,265	1,214	1,192	1,108	1,153	1,200	1,036
Jan	1,486	1,495	1,446	1,403	1,384	1,322	1,280	1,388	1,364	1,335	1,339	1,335	1,210	1,216
Feb	1,344	1,286	1,164	1,189	1,178	1,155	1,134	1,265	1,196	1,085	1,124	1,136	1,069	1,071
Mar	1,124	1,086	1,059	1,048	1,047	1,041	981	1,048	998	977	990	999	815	910
Apr	753	734	695	699	652	671	640	670	649	614	622	600	455	586
May	427	399	380	379	374	344	316	352	308	312	315	322	194	264
Jun	122	140	123	98	114	103	70	91	84	96	68	88	47	50
Jul	27	21	17	15	17	6	19	14	8	10	10	11	7	14
Aug	51	42	40	23	23	8	3	34	28	29	14	19	64	1
Sep	241	224	200	200	134	134	133	193	165	154	161	117	266	100
Oct	543	586	545	535	512	447	406	455	499	471	469	473	413	349
Winter	6,199	6,036	5,808	5,641	5,582	5,476	5,230	5,785	5,541	5,356	5,336	5,367	5,085	4,915
Summer	2,164	2,145	2,001	1,948	1,826	1,714	1,588	1,810	1,740	1,687	1,659	1,631	1,446	1,364
Gas Year	8,362	8,181	7,809	7,589	7,407	7,190	6,818	7,595	7,281	7,043	6,995	6,997	6,531	6,279
Max Daily	76.4	73.0	71.8	69.4	66.7	69.2	72.1	75.6	69.2	69.2	69.0	66.7	69.7	69.2

An easier interpretation of the data is shown below in Figures V-1 and V-2.

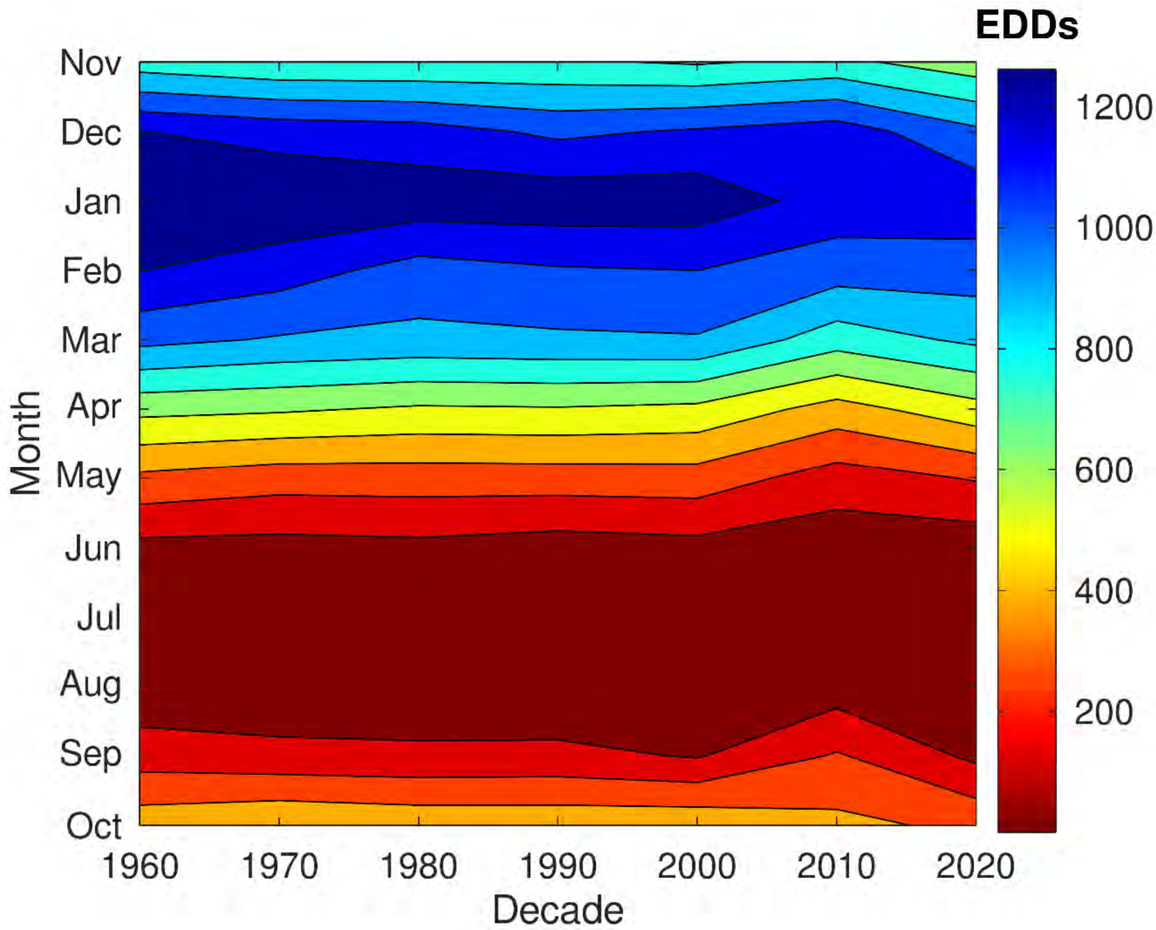
Figure V-1 Average EDD by Decade - Maine Division



Both figures show the decreasing trend of total EDDs between December through February, an the increasing size of summer EDDs from June to August. Overall what is shown is a decrease of amplitude of the sinusoidal propagation of total EDDs throughout a given year.

Based on an examination of these results and the desire to use consistent data sets across both Divisions, it was determined that the 30 year distribution was the most appropriate for predicting the following year EDD at this time. Therefore, the Normal Year EDD forecast and the Design Year and Design Day planning standard EDD were developed using a database of the most recent 30 years of weather data for both the Maine and New Hampshire Divisions.

Figure V-2: Average EDD by Decade - New Hampshire Division



Economic and Demographic Variables

Economic activity and demographic data to be used in the regression analysis were acquired from Moody's Analytics. Moody's Analytics provided separate data series for the Maine (Portland-South Portland Metropolitan Area) and New Hampshire (Rockingham and Strafford County) divisions. Historical data was obtained for the period of November 2014 through December 2022 (the "historical period") and forecast data was provided from January 2023 through December 2053. The data includes population, average household income, employment (manufacturing, non-agricultural, transportation and utilities), industrial production, gross metropolitan product, households, retail and retail sales specific to each state. Due to volatility in pricing (particularly over long periods of time) and multicollinearity with weather effectors the Company has removed pricing variables from its Use Per Customer models. Table V-7 summarizes the Global Insight economic and demographic data evaluated while developing the Customer Segment models.

Table V-7: Moody's Analytics Variables

Total Population (Thousands)
Households (Thousands)
Average Household Income (USD)
Industrial Production (Total)
Gross Metropolitan Product (Bil. USD)
Employment, Non-Agricultural (Thousands)
Employment, Manufacturing (Thousands)
Employment, Private Service Providing (Thousands)
Employment, Transportation & Utilities (Thousands)
Retail Sales (Bil. USD)
Unemployment Rate (%)

Figure V-3: Maine Division Economic Variables

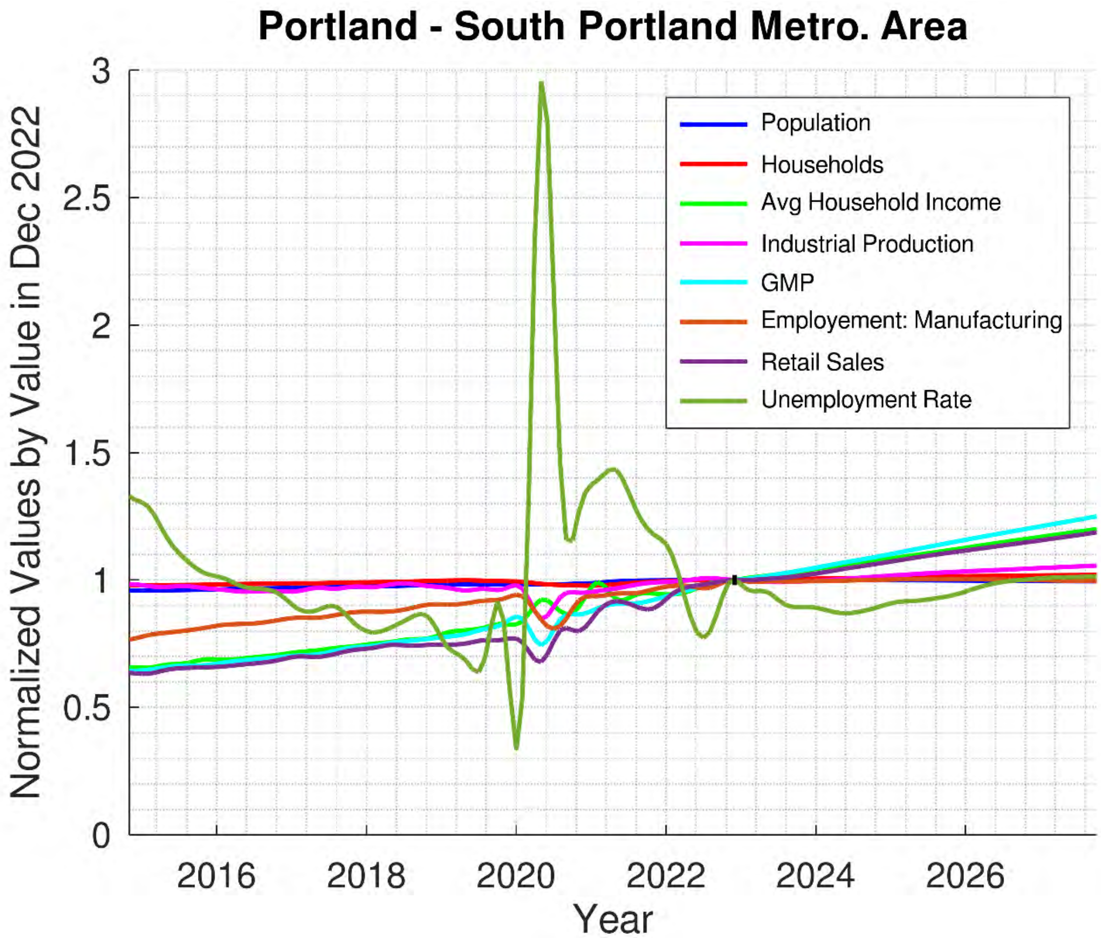
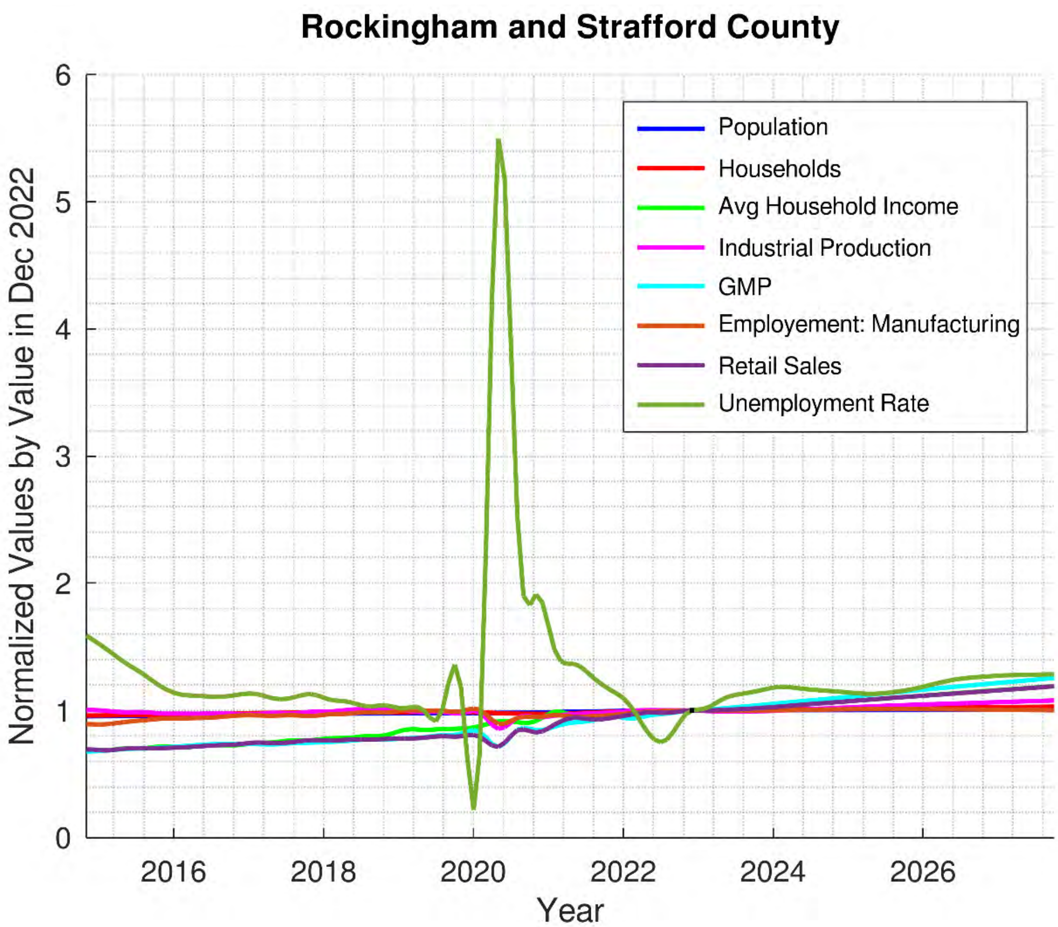


Figure V-3 above illustrates the change in the independent economic variables used for the Maine Division econometric forecasting. The figure shows each independent variable normalized by the value taken at the end of the dataset (December 2022). One can easily infer that certain variables were less affected by the COVID-19 Pandemic than others. I.e., population and households remained steady through 2020 to 2022, whereas the other variables saw increased variability. Figure V-4 below shows the same results for the New Hampshire Division.

Figure V-4: New Hampshire Division Economic Variables



Other Variables

The following adjustments were made, and additional variables were developed, for use in the Customer Segment models:

- Monthly indicator or trend variables were created to account for any systematic changes in the number of customers or use per customer that were a function of time.
- Dummy variables (or indicator variables) were created to represent time-related events. These time-related dummy variables equal 1 when that specific time-related event occurs, and equal 0 at other times.
- Interactive variables were created by multiplying dummy variables and selected independent variables to determine if the relationships between the dependent variable and the selected independent variables changed as a result of time-related events.
- Variables with time lags were created from several of the data series to test whether the impact of that variable on the number of customers or use per customer was not immediate, but instead is delayed.
- Household size was derived by dividing population by total households.

3. Customer Segment Model Results – Maine Division

This section summarizes the forecast results for each Customer Segment model for Northern's Maine Division, including the buildup of customer demand by segment and ultimately total demand for the Maine Division. Detailed statistical documentation including: (a) regression model output; (b) definitions of all variables used; (c) historical actual values, historical fitted values derived from each model and model residuals; and (d) the results of the statistical tests that were performed for each Customer Segment model are provided in Appendix 1.

The Company's customers fund Energy Efficiency programs administered by Efficiency Maine. Savings from energy efficiency measures installed before the forecast period (prior to December 2022) are assumed to be built into the history of actual customer demand. That is, in the absence of historical energy efficiency measures having been installed, gas sales during the historical period would have been higher than actually occurred. Projected incremental energy efficiency savings, reflecting measures installed during and after December 2022, are tallied and deducted from the Customer Segment demand forecasts. The resulting forecasts after reduction for energy efficiency savings are referred to as "Net Demand".

The Customer Segment model results are presented as follows for the Maine Division, in this Section IV.C.3, and for the New Hampshire Division in the following Section IV.C.4.

Table V-8: Structure of Customer Segment Model Results Section

Sub-Section	Description
a) Residential Forecast	Customer Model results times Use per Customer results
b) Residential Energy Efficiency Savings	Incremental Savings from Residential EE Programs
c) Residential Net Demand	= Residential Forecast - Residential EE Savings
d) C&I Low Load Factor (LLF) Forecast	Customer Model results times Use per Customer results
e) C&I High Load Factor (HLF) Forecast	Customer Model results times Use per Customer results
f) C&I Energy Efficiency Savings	Incremental Savings from C&I EE Programs
g) C&I Net Demand	= C&I LLF Forecast + C&I HLF Forecast - C&I EE Savings
h) Incremental Energy Efficiency Savings	= Residential EE Savings + C&I EE Savings
i) Customer Segment Net Demand	= Residential Net Demand + C&I Net Demand

a) Residential Customer Segment Forecast – Maine Division

The Residential Segment is the Maine Division's largest Customer Segment in terms of number of customers accounting for 72% of all customers. However, the Customer Segment represents only 15% of the total annual demand. In the final regression equation that was selected to predict Residential customers, total households was statistically significant. In the final regression equation that was selected to predict Residential use per customer, billing cycle EDD was statistically significant with an additional effector from household size. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table V-9 below summarizes the Residential Customer Segment model results for customer growth, use per customer, and residential demand for the forecast period as compared to the historical reference period.[87]

Table V-9: Residential Customer Segment Forecast – Maine Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2017/18	22,877	725	16,578,126
2018/19	23,502	748	17,573,890
2019/20	24,186	743	17,961,128
2020/21	24,385	707	17,232,086
2021/22	24,587	706	17,363,056
CAGR	1.8%	-0.6%	1.2%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2022/23	24,922	703	17,509,292
2023/24	25,285	713	18,037,687
2024/25	25,628	712	18,258,773
2025/26	25,972	712	18,480,771
2026/27	26,312	711	18,703,380
CAGR	1.4%	0.3%	1.7%

Over the forecast period, the number of Maine Residential customers is expected to grow at an annual rate of 1.4% compared to a growth rate of 1.8% over the historical reference period. Use per customer for the Residential Customer Segment is expected to increase to 0.3% annually compared to the historical reference period rate of -0.6%. The Residential demand forecast was calculated by multiplying the forecasted number of Residential customers each month by the forecasted Residential use per customer for that month. Over the forecast period, Residential demand is expected to increase to 1.7% from 1.2% over the historical reference period.

[87] Throughout the demand forecast section, historical and forecast data are provided along with compound annual growth rates ("CAGR"), which are calculated as the value in the final year divided by the value in the initial year raised to the power of 1 divided by the number of years in the period minus one.

b) Residential Energy Efficiency Savings – Maine Division

The Residential demand forecast was reduced by expected incremental energy savings associated with Residential energy efficiency program targets. The estimated incremental energy savings associated with current Residential energy efficiency programs for the forecast period for the Maine Division are listed in the tables below. Historical energy efficiency savings are assumed to already be reflected in metered consumption. Although previously installed efficiency measures will continue to achieve savings, those savings are already embedded in historical usage. Since the historical data used for the demand forecast extends through December 2022, incremental efficiency savings are those associated with measures expected to be installed beginning in January 2023. In determining the pattern and level of efficiency savings, Northern assumed that savings targets are met, that measures are installed ratably over twelve months each year, and that realized savings vary with customer demand patterns. For example, realized savings are expected to be very low in July and August when customer consumption is low and at their highest in January and February when customers use the most natural gas.

Table V-10 below provides the annual energy efficiency savings targets for Residential EE programs operated by Efficiency Maine, as reflected in the 2023-2025 Proposed Triennial Plan. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2025). Since Efficiency Maine administers their programs at the state level, Northern assumed that 57.5% of natural gas related savings projections would apply to Northern customers.[88]

Table V-10: Residential Energy Efficiency Savings – Maine Division (Annual MMBtu)[89]

	Forecast FY 2023	Forecast FY 2024	Forecast FY 2025	Forecast FY 2026	Forecast FY 2027	Forecast FY 2028
Retail Initiatives	0	-	-	-	-	-
Home Energy Savings Program	7,611	7,492	7,492	7,492	7,492	7,492
Low Income Initiatives	770	695	684	684	684	684
State Total - Residential	8,381	8,188	8,176	8,176	8,176	8,176
NUI Share (57.5%)	4,819	4,708	4,701	4,701	4,701	4,701

Table V-11 demonstrates the conversion of fiscal year energy efficiency savings targets into monthly savings that correlate with Residential customer consumption through the first gas year, which runs from November 2023 through October 2024. The calculation shown in Table V-11 is carried forward throughout the forecast period. Target savings are shown in MMBtu, so the values shown in Table V-10 were multiplied by 10 to convert to therms (Th). Measures are assumed to be installed ratably, so the annual savings targets are divided by 12 and listed for each month of the fiscal year. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the Residential monthly

88 See Appendix 4, page 5.

89 Data from Appendix B of Proposed Triennial Plan for Fiscal Years 2020-2022, Efficiency Maine Trust, October 3, 2018.

demand pattern. The demand pattern is based on a 4 year history of weather adjusted normal demand from November 2018 through October 2022. The result is the incremental efficiency savings each month. The efficiency savings for the gas year of 2023/24 tallied at the bottom of Table V-11 tie to the Residential EE Savings shown in the table that follows.

Table V-11: Residential Incremental EE Savings – Maine Division (Th)

Month	New Installs	Cumulative Installs	Residential Pattern	Incremental EE Savings (Th)
Nov 2022	4,016		7.19%	
Dec 2022	4,016		13.07%	
Jan 2023	4,016	4,016	17.77%	714
Feb 2023	4,016	8,031	18.03%	1,448
Mar 2023	4,016	12,047	15.99%	1,927
Apr 2023	4,016	16,063	10.19%	1,637
May 2023	4,016	20,079	6.17%	1,239
Jun 2023	4,016	24,094	2.99%	720
Jul 2023	3,923	28,017	1.88%	527
Aug 2023	3,923	31,940	1.63%	522
Sep 2023	3,923	35,863	1.81%	650
Oct 2023	3,923	39,786	3.28%	1,306
Nov 2023	3,923	43,709	7.19%	3,141
Dec 2023	3,923	47,633	13.07%	6,224
Jan 2024	3,923	51,556	17.77%	9,162
Feb 2024	3,923	55,479	18.03%	10,002
Mar 2024	3,923	59,402	15.99%	9,499
Apr 2024	3,923	63,325	10.19%	6,454
May 2024	3,923	67,248	6.17%	4,149
Jun 2024	3,923	71,171	2.99%	2,126
Jul 2024	3,918	75,088	1.88%	1,412
Aug 2024	3,918	79,006	1.63%	1,291
Sep 2024	3,918	82,924	1.81%	1,502
Oct 2024	3,918	86,841	3.28%	2,850
Gas Year 2023/24				57,812

c) Residential Customer Segment Net Demand – Maine Division

Residential Net Demand for the Maine Division is summarized in Table V-12 below as Residential Customer Segment demand less expected residential energy efficiency savings ("EE Savings"). Residential Net Demand is projected to increase by 1.4% annually over the forecast period. The primary driver of residential customer growth is total households and the primary driver of residential use per customer is weather with an additional effect from size of household.

Table V-12: Residential Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2022/23	17,509,292	-10,688	17,498,604
2023/24	18,037,687	-57,812	17,979,875
2024/25	18,258,773	-104,843	18,153,929
2025/26	18,480,771	-151,855	18,328,916
2026/27	18,703,380	-198,867	18,504,514
CAGR	1.7%	107.7%	1.4%

d) C&I Low Load Factor Customer Segment Forecast – Maine Division

The C&I LLF Customer Segment is the Maine Division's second largest Customer Segment in terms of number of customers, with about 34% as many customers as the Residential Heating segment and representing 24% of all customers. However, the C&I Low Load Factor Customer Segment is the largest in terms of demand representing 63% of the total annual load. In the final regression equation that was selected to predict C&I LLF customers, gross metropolitan product was statistically significant at a lag of three. In the final regression equation that was selected to predict C&I LLF use per customer, Bill Cycle EDD and gross metropolitan product at a lag of 3 were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table V-13 below summarizes the C&I LLF customer model results for customer growth, use per customer, and C&I LLF demand for the forecast period as compared to the historical reference period.

Table V-13: C&I LLF Customer Segment Forecast – Maine Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2017/18	8,020	7,957	63,819,648
2018/19	8,061	8,172	65,874,075
2019/20	8,092	8,303	67,194,513
2020/21	8,149	8,537	69,564,680
2021/22	8,279	8,743	72,389,437
CAGR	0.8%	2.4%	3.2%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2022/23	8,419	8,828	74,321,471

2023/24	8,516	8,994	76,591,209
2024/25	8,626	9,149	78,916,544
2025/26	8,739	9,305	81,323,078
2026/27	8,847	9,459	83,684,313
CAGR	1.2%	1.7%	3.0%

Over the forecast period, the number of Maine C&I LLF customers is projected to increase by 1.2% annually compared to the growth rate of 0.8% over the historical reference period. Use per customer for the C&I LLF Customer Segment is expected to grow by 1.7% annually over the forecast down slightly from the historical period result of 2.4%. The C&I LLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF customers each month by the forecasted C&I LLF use per customer for that month. Over the forecast period, C&I LLF demand is expected to reduce to 3.0% annual growth from 3.2% annual growth seen in the historical reference period. This Customer Segment continues to remain The Company's fastest growing class.

e) C&I High Load Factor Customer Segment Forecast – Maine Division

The Maine C&I HLF Customer Segment encompasses about 14% as many customers as the C&I LLF segment and represents only 3.4% of the total customers. The C&I HLF segment consumes about 36% of the gas demand of the C&I LLF segment and 22% of the total load. In the final regression equation that was selected to predict C&I HLF customers, an interaction variable of gross metropolitan produce lagged by 3 and multiplied by a dummy variable were statistically significant. In the final regression equation that was selected to predict C&I HLF use per customer, employment rate lagged by 1 and bill cycle EDD were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table V-14 below summarizes the C&I HLF customer model results for customer growth, use per customer, and C&I HLF demand for the forecast period as compared to the historical reference period.

Table V-14: C&I HLF Customer Segment Forecast – Maine Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2017/18	1,150	23,578	27,114,493
2018/19	1,170	24,082	28,165,703
2019/20	1,149	23,472	26,959,209
2020/21	1,150	23,209	26,692,537
2021/22	1,160	22,339	25,920,475
CAGR	0.2%	-1.3%	-1.1%

Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2022/23	1,166	23,184	27,044,002
2023/24	1,165	23,741	27,665,434
2024/25	1,166	23,695	27,639,137
2025/26	1,168	23,611	27,565,855
2026/27	1,169	23,554	27,523,794
CAGR	0.0%	0.4%	0.4%

Over the forecast period, the number of Maine C&I HLF customers is projected to stagnate, which is indicative of the 0.2% growth experienced over the historical reference period. It is important to note however that the intra-year values do experience change, just that the 5 year CAGR results in a negligible percent change. Use per customer for the C&I HLF Customer Segment is expected to increase to 0.4% through the forecast period a positive change from a use per customer of -1.3% over the historical reference period. The C&I HLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF customers each month by the forecasted C&I HLF use per customer for that month. Over the forecast period, C&I HLF demand growth is expected to increase at an average annual rate of about 0.4%, compared to the historical growth rate of 1.1%.

f) C&I Energy Efficiency Savings – Maine Division

Table V-15 below provides the annual energy efficiency savings targets for C&I EE programs operated by Efficiency Maine, as reflected in the 2023-2025 Proposed Triennial Plan. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2026). Since Efficiency Maine administers their programs at the state level, Northern assumed that 57.5% of natural gas related savings projections would apply to Northern customers.

Table V-15: C&I Energy Efficiency Savings – Maine Division (Annual MMBtu)

	Forecast FY 2023	Forecast FY 2024	Forecast FY 2025	Forecast FY 2026	Forecast FY 2027	Forecast FY 2028
C&I Custom Program	80,987	55,300	55,300	55,300	55,300	55,300
C&I Prescriptive Program	41,107	11,791	11,791	11,791	11,791	11,791
Distributor Initiatives	4,914	3,497	2,640	2,640	2,640	2,640
State Total - C&I Customers	127,008	70,588	69,731	69,731	69,731	69,731
NUI Share (57.5%)	73,027	40,586	40,094	40,094	40,094	40,094

Table V-16 below provides a similar conversion of fiscal year energy efficiency savings targets to monthly savings for C&I customers to the conversion provided in Table V-11 for Residential customers. Again, target savings are shown in MMBtu, so the values shown in Table V-15 were multiplied by 10, and measures are assumed to be installed ratably, so the annual savings targets are divided by 12. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the C&I monthly demand pattern to yield the incremental efficiency savings each month. The efficiency savings for the gas year of 2023/24 tallied at the bottom of Table V-16 tie to the C&I EE Savings shown in the table that follows.

Table V-16: C&I Incremental EE Savings – Maine Division (Th)

Month	New Installs	Cumulative Installs	Residential Pattern	Incremental EE Savings (Th)
Nov 2022	60,856		8.63%	
Dec 2022	60,856		11.77%	
Jan 2023	60,856	60,856	14.40%	8,766
Feb 2023	60,856	121,711	14.04%	17,086
Mar 2023	60,856	182,567	12.98%	23,696
Apr 2023	60,856	243,422	9.28%	22,597
May 2023	60,856	304,278	6.51%	19,817
Jun 2023	60,856	365,134	4.49%	16,386
Jul 2023	33,822	398,956	4.02%	16,055
Aug 2023	33,822	432,778	4.00%	17,307
Sep 2023	33,822	466,600	4.24%	19,771
Oct 2023	33,822	500,422	5.63%	28,190
Nov 2023	33,822	534,244	8.63%	46,120
Dec 2023	33,822	568,066	11.77%	66,846
Jan 2024	33,822	601,888	14.40%	86,702
Feb 2024	33,822	635,710	14.04%	89,240
Mar 2024	33,822	669,532	12.98%	86,903
Apr 2024	33,822	703,354	9.28%	65,292
May 2024	33,822	737,176	6.51%	48,012
Jun 2024	33,822	770,998	4.49%	34,601
Jul 2024	33,411	804,409	4.02%	32,372
Aug 2024	33,411	837,821	4.00%	33,504
Sep 2024	33,411	871,232	4.24%	36,917
Oct 2024	33,411	904,644	5.63%	50,961
Gas Year 2023/24				677,469

g) C&I Customer Segment Net Demand – Maine Division

C&I Total Net Demand for the Maine Division is summarized in Table V-17 below as the sum of the C&I LLF Customer Segment demand and the C&I HLF Customer Segment demand less expected C&I Total energy efficiency savings. C&I Total Net Demand is projected to increase by 2.0% annually over the forecast period.

Table V-17: C&I Customer Segment Net Demand (Th) - Maine Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2022/23	74,321,471	27,044,002	-189,672	101,175,801
2023/24	76,591,209	27,665,434	-677,469	103,579,175
2024/25	78,916,544	27,639,137	-1,079,733	105,475,948
2025/26	81,323,078	27,565,855	-1,480,670	107,408,262
2026/27	83,684,313	27,523,794	-1,881,607	109,326,500
CAGR	3.0%	0.4%	77.5%	2.0%

h) Customer Segment Net Demand Forecast – Maine Division

The result of the Maine Division Customer Segment modeling is presented below in Table V-18, where the demand determined by Customer Segment assuming normal weather and reduced for energy efficiency savings is tallied for the entire Division.

Table V-18: Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Normal Net Demand	C&I Normal Net Demand	Division Normal Net Demand
2022/23	17,498,604	101,175,801	118,674,404
2023/24	17,979,875	103,579,175	121,559,049
2024/25	18,153,929	105,475,948	123,629,877
2025/26	18,328,916	107,408,262	125,737,178
2026/27	18,504,514	109,326,500	127,831,014
CAGR	1.4%	2.0%	1.9%

4. Customer Segment Model Results – New Hampshire Division

This section summarizes the forecast results for each Customer Segment model for Northern's New Hampshire Division, including the buildup of customer demand by segment and ultimately total demand for the New Hampshire Division. Detailed statistical documentation including: (a) regression model output; (b) definitions of all variables used; (c) historical actual values, historical fitted values derived from each model and model residuals; and (d) the results of the statistical tests that were performed for each Customer Segment model are provided in Appendix 1. The regression models utilized to estimate Customer Segment demand for the New Hampshire Division were similar in method but utilized different independent variables where appropriate for correlation.

The Company regularly implements Energy Efficiency under programs developed in coordination with the other New Hampshire gas and electric utilities. Savings from energy efficiency measures installed during the historical period (through December 2022) are assumed to be built into the history of actual customer demand. Projected incremental energy efficiency savings, reflecting measures installed during and after January 2023, are tallied and deducted from the Customer Segment demand forecasts. The resulting forecasts after reduction for energy efficiency savings are referred to as "Net Demand".

a) Residential Customer Segment Forecast – New Hampshire Division

Residential is the New Hampshire Division's largest Customer Segment in terms of number of customers, but is smaller than both the C&I LLF and C&I HLF segments in terms of demand. In the final regression equation that was selected to predict Residential customers, total households were statistically significant. In the final regression equation that was selected to predict Residential use per customer, Bill Cycle EDD was statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table V-19 below summarizes the Residential customer model results for customer growth, use per customer, and Residential demand for the forecast period as compared to the historical reference period.

Table V-19: Residential Customer Segment Forecast – New Hampshire Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2017/18	26,148	723	18,896,382
2018/19	26,774	728	19,501,540
2019/20	27,467	701	19,241,851
2020/21	28,316	681	19,271,956
2021/22	28,876	677	19,560,795
CAGR	2.5%	-1.6%	0.9%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2022/23	29,529	715	21,107,367
2023/24	30,263	705	21,330,398
2024/25	30,984	705	21,837,613
2025/26	31,709	705	22,349,644
2026/27	32,435	705	22,861,605
CAGR	2.4%	-0.4%	2.0%

Over the forecast period, the number of New Hampshire Residential customers is expected to grow at a rate of 2.4% annually which is consistent with the 2.5% growth rate observed over the historical reference period. Use per customer for the Residential Customer Segment is expected to reduce to -0.4%, which shows some increased use per customers from the historical reference period. The Residential demand forecast was calculated by multiplying the forecasted number of Residential customers each month by the forecasted Residential use per customer for that month. Over the forecast period, Residential demand is expected to increase at a rate of 2.0% annually returning to a more normal growth rate in line with the previous IRP submission after the volatility experienced during the COVID-19 Pandemic.

b) Residential Energy Efficiency Savings – New Hampshire Division

As was done in the Customer Segment forecasts for the Maine Division, the demand forecasts are reduced by expected incremental energy savings associated with energy efficiency program targets. The estimated incremental energy savings for Residential Customers in the New Hampshire Division over the forecast period are listed in the tables below. Historical energy efficiency savings are assumed to already be reflected in metered consumption. Although previously installed efficiency measures will continue to achieve savings, those savings are already embedded in historical usage. Since the historical data used for the demand forecast extends through December 2022, incremental efficiency savings are those associated with measures expected to be installed beginning in January 2023. In determining the pattern and level of efficiency savings, Northern assumed that savings targets are met, that measures are installed ratably over twelve months each year, and that realized savings vary with customer demand patterns. For example, realized savings are expected to be very low in July and August when customer consumption is low and at their highest in January and February when customers use the most natural gas.

Table V-20 below provides the annual energy efficiency savings targets for Residential EE programs operated by the Company, as reflected in the most recent Triennial Plan, which covers the years of 2021-2023. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2023).[90]

Table V-20: Residential Energy Efficiency Savings – New Hampshire Division (Annual MMBtu)

	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027
Home Energy Assistance (Low Inc)	2,208	2,208	2,208	2,208	2,208
Energy Star Homes	2,637	2,637	2,637	2,637	2,637
Home Performance w/Energy Star	1,799	1,799	1,799	1,799	1,799
Energy Star Products	1,836	1,836	1,836	1,836	1,836
Home Energy Reports / Behavior	5,847	5,847	5,847	5,847	5,847
Residential Total	14,327	14,327	14,327	14,327	14,327

Table V-21 demonstrates the conversion of annual energy efficiency savings targets into monthly savings that correlate with Residential customer consumption through the first gas year, which runs from November 2023 through October 2024. The calculation shown in Table V-21 is carried forward throughout the forecast period. Target savings are shown in Therms (Th), so the values shown in Table V-20 were multiplied by 10, and measures are assumed to be installed ratably, so the annual savings targets are divided by 12 and listed for each month of the year. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the New Hampshire Division Residential monthly demand pattern. The demand pattern is based on a 4 year history of weather adjusted normal demand from November 2018 through October 2022. The result is the incremental efficiency savings each month. The efficiency savings for the gas year of 2023/24 tallied at the bottom of Table V-21 tie to the Residential EE Savings shown in the table that follows.

[90] Appendix 4, page 6.

Table V-21: Residential Incremental EE Savings – New Hampshire Division (Th)

Month	New Installs	Cumulative Installs	Residential Pattern	Incremental EE Savings (Th)
Nov 2022	11,939		7.26%	
Dec 2022	11,939		13.54%	
Jan 2023	11,939	11,939	17.47%	2,086
Feb 2023	11,939	23,878	18.13%	4,328
Mar 2023	11,939	35,818	15.88%	5,690
Apr 2023	11,939	47,757	9.91%	4,731
May 2023	11,939	59,696	5.89%	3,514
Jun 2023	11,939	71,635	3.22%	2,305
Jul 2023	11,939	83,574	1.95%	1,632
Aug 2023	11,939	95,513	1.77%	1,689
Sep 2023	11,939	107,453	1.88%	2,023
Oct 2023	11,939	119,392	3.10%	3,699
Nov 2023	11,939	131,331	7.26%	9,532
Dec 2023	11,939	143,270	13.54%	19,404
Jan 2024	11,939	155,209	17.47%	27,120
Feb 2024	11,939	167,148	18.13%	30,299
Mar 2024	11,939	179,088	15.88%	28,448
Apr 2024	11,939	191,027	9.91%	18,925
May 2024	11,939	202,966	5.89%	11,948
Jun 2024	11,939	214,905	3.22%	6,914
Jul 2024	11,939	226,844	1.95%	4,430
Aug 2024	11,939	238,783	1.77%	4,223
Sep 2024	11,939	250,723	1.88%	4,720
Oct 2024	11,939	262,662	3.10%	8,137
Gas Year 2023/24				174,100

c) Residential Customer Segment Net Demand – New Hampshire Division

Residential Net Demand for the New Hampshire Division is summarized in Table V-22 below as Residential Customer Segment demand less expected residential energy efficiency savings. Residential Net Demand is projected to increase by 1.4% annually over the planning period. As stated above, the primary drivers of residential demand growth are weather and customer growth.

Table V-22: Residential Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2022/23	21,107,367	-31,697	21,075,670
2023/24	21,330,398	-174,100	21,156,297
2024/25	21,837,613	-317,370	21,520,243
2025/26	22,349,644	-460,640	21,889,003
2026/27	22,861,605	-603,910	22,257,695
CAGR	2.0%	108.9%	1.4%

d) C&I Low Load Factor Customer Segment Forecast – New Hampshire Division

The C&I LLF Customer Segment is the New Hampshire Division's second largest Customer Segment in terms of demand and comprises about five times as many customers as the C&I HLF Customer Segment. In the final regression equation selected to predict C&I LLF customers, average household income was statistically significant. In the final regression equation used to predict C&I LLF use per customer, Bill Cycle EDD was statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table V-23 below summarizes the C&I LLF customer model results for customer growth, use per customer, and C&I LLF demand for the forecast period as compared to the historical reference period.

Table V-23: C&I LLF Customer Segment Forecast – New Hampshire Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2017/18	5,747	5,486	31,528,565
2018/19	5,749	5,409	31,099,505
2019/20	5,807	5,348	31,055,191
2020/21	5,891	5,203	30,650,731
2021/22	5,911	5,461	32,281,756
CAGR	0.7%	-0.1%	0.6%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2022/23	5,926	5,562	32,963,864
2023/24	5,958	5,477	32,632,892
2024/25	5,995	5,497	32,951,041
2025/26	6,034	5,517	33,288,873
2026/27	6,073	5,537	33,627,387
CAGR	0.6%	-0.1%	0.5%

Over the forecast period, the number of New Hampshire C&I LLF customers is projected to increase by 0.6% annually a decrease of 0.1% from the historical reference period. Use per customer for the C&I LLF Customer Segment is expected to grow remain at a constant decrease of -0.1% annually which matches the historical reference period. Not that the year over year changes in the forecast only show a decreasing annual rate between 2022/23 and 2023/24, omitting the first year of the forecasts provides a CAGR of 0.36%. The C&I LLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF customers each month by the forecasted C&I LLF use per customer for that month. Over the forecast period, C&I LLF demand is expected to increase by0.5% annually, driven primarily by continued customer growth, resulting in a minimal decline in demand growth relative to the historical reference period.

e) C&I High Load Factor Customer Segment Forecast – New Hampshire Division

The New Hampshire C&I HLF Customer Segment has about one fifth as many customers as the C&I LLF segment, but is the largest Customer Segment in terms of demand. In the final regression equation that was selected to predict C&I HLF customers, gross metropolitan product lagged by 3 was a significant regressor and was used to create an interaction variable starting in October of 2018. In the final regression equation that was used to predict C&I HLF use per customer, employment in manufacturing and bill cycle EDD were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table V-24 below summarizes the C&I HLF customer model results for customer growth, use per customer, and C&I HLF demand for the forecast period as compared to the historical reference period.

Table V-24: C&I HLF Customer Segment Forecast – New Hampshire Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2017/18	1,097	31,793	34,866,775
2018/19	1,142	32,859	37,533,210
2019/20	1,147	29,255	33,545,811
2020/21	1,146	31,552	36,168,636
2021/22	1,152	31,887	36,744,675
CAGR	1.2%	0.1%	1.3%
Gas Year	**Average Customers Forecast**	**Use Per Customer (Th/Customer)**	**Demand (Th) Normal Forecast**
2022/23	1,154	32,758	37,810,805
2023/24	1,158	32,677	37,856,001
2024/25	1,162	32,890	38,203,262
2025/26	1,165	32,861	38,273,456
2026/27	1,168	32,707	38,190,350
CAGR	0.3%	0.0%	0.3%

Over the forecast period, the number of New Hampshire C&I HLF customers is projected to increase slightly by 0.3% annually compared to an annual growth rate of 1.2% over the historical reference period, though it is important to note that the first historical year 2017/18 saw a rapid increase in customers to 2018/19, where the growth remained significantly less following. Use per customer for the C&I HLF Customer Segment is to remain almost constant over the forecast period which reflects well to 0.1% growth over this historical reference period. The C&I HLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF customers each month by the forecasted C&I HLF use per customer for that month. Over the forecast period, C&I HLF customer demand is expected to increase by about 0.3% annually, which is a decrease from the 1.3% annual growth over the historical reference period.

f) C&I Energy Efficiency Savings – New Hampshire Division

Table V-25 below provides the annual energy efficiency savings targets for C&I programs operated by the Company, as reflected in the 2021-2023 Triennial Plan. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2023).

Table V-25: C&I Energy Efficiency Savings – New Hampshire Division (Annual MMBtu)

	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027
Large Business Energy Solutions	14,308	14,308	14,308	14,308	14,308
Small Business Energy Solutions	10,830	10,830	10,830	10,830	10,830
C&I Total	25,138	25,138	25,138	25,138	25,138

Table V-26 provides a similar conversion of year energy efficiency savings targets to monthly savings for C&I customers to the conversion provided in Table V-21 for Residential customers. Again, target savings are shown in Therms (Th), so the values shown in Table V-25 were multiplied by 10, and measures are assumed to be installed ratably, so the annual savings targets are divided by 12. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the C&I monthly demand pattern to yield the incremental efficiency savings each month. The efficiency savings for the gas year of 2023/24 tallied at the bottom of Table V-26 tie to the C&I EE Savings shown in the table that follows.

Table V-26: C&I Incremental EE Savings – New Hampshire Division (Th)

Month	New Installs	Cumulative Installs	Residential Pattern	Incremental EE Savings (Th)
Nov 2022	20,948		8.29%	
Dec 2022	20,948		10.78%	
Jan 2023	20,948	20,948	13.12%	2,752
Feb 2023	20,948	41,896	12.99%	5,451
Mar 2023	20,948	62,845	12.15%	7,642
Apr 2023	20,948	83,793	8.76%	7,345
May 2023	20,948	104,741	6.86%	7,183
Jun 2023	20,948	125,689	5.48%	6,885
Jul 2023	20,948	146,637	5.17%	7,575
Aug 2023	20,948	167,585	4.99%	8,361
Sep 2023	20,948	188,534	5.15%	9,699
Oct 2023	20,948	209,482	6.26%	13,101
Nov 2023	20,948	230,430	8.29%	19,076
Dec 2023	20,948	251,378	10.78%	27,049
Jan 2024	20,948	272,326	13.12%	35,772
Feb 2024	20,948	293,274	12.99%	38,154
Mar 2024	20,948	314,223	12.15%	38,212
Apr 2024	20,948	335,171	8.76%	29,381
May 2024	20,948	356,119	6.86%	24,421
Jun 2024	20,948	377,067	5.48%	20,656
Jul 2024	20,948	398,015	5.17%	20,561
Aug 2024	20,948	418,963	4.99%	20,901
Sep 2024	20,948	439,912	5.15%	22,631
Oct 2024	20,948	460,860	6.26%	28,821
Gas Year 2023/24				325,637

g) C&I Customer Segment Net Demand – New Hampshire Division

C&I Total Net Demand for the New Hampshire Division is summarized in Table V-27 below as the sum of the C&I LLF Customer Segment demand and the C&I HLF Customer Segment demand less expected C&I Total energy efficiency savings. C&I Total Net Demand is projected to remain almost constant annually over the forecast period.

Table V-27: C&I Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2022/23	32,963,864	37,810,805	-75,993	70,698,676
2023/24	32,632,892	37,856,001	-325,637	70,163,255
2024/25	32,951,041	38,203,262	-577,015	70,577,288
2025/26	33,288,873	38,273,456	-828,393	70,733,936
2026/27	33,627,387	38,190,350	-1,079,771	70,737,966
CAGR	0.5%	0.3%	94.2%	0.0%

h) Customer Segment Net Demand Forecast – New Hampshire Division

The end result of the New Hampshire Division Customer Segment modeling is presented below in Table V-28, where the demand determined by Customer Segment, assuming normal weather and reduced for energy efficiency savings is tallied for the entire Division resulting in a forecasted net demand growth for the New Hampshire division of 0.3%.

Table V-28: Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Normal Net Demand	C&I Normal Net Demand	Division Normal Net Demand
2022/23	21,075,670	70,698,676	91,774,346
2023/24	21,156,297	70,163,255	91,319,553
2024/25	21,520,243	70,577,288	92,097,530
2025/26	21,889,003	70,733,936	92,622,939
2026/27	22,257,695	70,737,966	92,995,660
CAGR	1.4%	0.0%	0.3%

D. Normal Year Throughput Forecast

Normal Year Throughput represents the total gas required to be delivered to the Company's system in a given year to provide service to all customers under normal weather conditions. The Normal Year Throughput forecasts are developed by adjusting the Customer Segment Model net demand forecasts to reflect calendar months and then adding Company Use and Lost and Unaccounted for Gas.

1. Company Use

Company Use includes natural gas used to heat Company buildings, to run the Lewiston LNG plant, and to pre-heat gas[91]. In the regression equations that were selected to predict Company Use for the Maine and New Hampshire Divisions, Bill Cycle EDD and monthly dummy variables were statistically significant. Over the forecast period, Company Use for both the Maine and New Hampshire Divisions is projected to remain constant as shown in Table V-29 below. For convenience, both normal year and design year Company Use are listed below. Design year Company Use will be utilized in Section V, Planning Load Forecast.

Table V-29: Northern Company Use - Normal Year, Design Year (Dth)

	Normal Year			Design Year		
Gas Year	Maine Division	NH Division	Total Company	Maine Division	NH Division	Total Company
2019/20	9,784	1,782	11,566	10,472	2,016	12,489
2020/21	10,051	1,839	11,890	10,907	2,016	12,924
2021/22	10,051	1,839	11,890	10,907	2,016	12,924
2022/23	10,051	1,839	11,890	10,907	2,016	12,924
2023/24	10,051	1,839	11,890	10,907	2,016	12,924
CAGR	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

2. Lost and Unaccounted for Gas

The Customer Segment and Company Use forecasts discussed above represent the projected gas use, measured at the customer meter on a billing period basis. To produce forecasts that represent gate station measures, the Customer Segment and Company Use forecasts were adjusted for lost and unaccounted for gas. Four years of historical calendar month total throughput data (measured at the gate station) and billing month gas use (measured at the customer meter) (i.e., “Gas Accounted For”), from April 2018 through December 2022, was compiled to develop forecasts of percentage lost and unaccounted for gas sales by Division. Table V-30 and Table V-31 below show the lost and unaccounted for sales percentage calculations for the Maine and New Hampshire Divisions respectively. The tables also show the Company Gas Allowance, which is the sum of Company Use and Lost and Unaccounted for Gas. Retail marketers serving Transportation Service customers are required to deliver gas to the Company’s gate stations to meet their customers’ metered usage grossed up by the Company Gas Allowance. The Company Gas Allowance is reviewed in Section V, Planning Load Forecast.

[91] In some circumstances, gas is pre-heated to counter the Joule-Thomson effect and prevent damage to downstream pressure regulating equipment or frost heaves above large mains that are located a short distance downstream from a regulator station.

Table V-30: Lost and Unaccounted For Sales (Dth) – Maine Division

Period	Total System Throughput	Total Retail Billed Sales	Company Use	Lost and Unaccounted For	Company Gas Allowance
5/18-4/19	11,392,367	11,182,672	10,624	199,072	209,696
5/19-4/20	11,076,637	10,914,972	9,597	152,068	161,665
5/20-4/21	10,988,432	10,914,346	9,804	64,282	74,086
5/21-4/22	11,423,528	11,282,851	10,180	130,497	140,677
Period	44,880,964	44,294,840	40,205	545,919	586,124
Percent			0.09%	1.22%	1.31%

Table V-31: Lost and Unaccounted For Sales (Dth) – New Hampshire Division

Period	Total System Throughput	Total Retail Billed Sales	Company Use	Lost and Unaccounted For	Company Gas Allowance
6/14-5/15	8,869,889	8,817,370	1,886	50,633	52,519
6/15-5/16	8,520,630	8,385,888	1,914	132,828	134,742
6/16-5/17	8,350,891	8,256,691	1,882	92,318	94,200
6/17-5/18	8,448,420	8,398,962	1,850	47,608	49,458
Period	34,189,830	33,858,911	7,532	323,387	330,919
Percent			0.02%	0.95%	0.97%

3. Normal Year Throughput Forecasts

As indicated in Table V-1, throughput is measured on a calendar basis and reported in Dth. Calculation of the Normal Year Throughput forecast starts by first adjusting the net demand forecast as developed using the Customer Segment models, which utilize normal billing cycle monthly weather data, to reflect calendar months. Calendarization factors were developed using the average relationship between monthly billed sales and monthly calendar throughput over the 48-month period of June 2014 through May 2018. The Calendarization process does not increase or decrease the demand forecast, but rather restates the monthly pattern of demand. Since the Customer Segment Models are developed in therms (Th), the unit used for retail billing, and throughput is expressed in dekatherms (Dth), the adjusted net demand is divided by 10.[92] Finally, Company Use and Lost and Unaccounted for Gas are added to yield normal throughput. Normal Year Throughput represents the total gas required to be delivered to the Company's system in a given year to provide service to all customers under normal weather conditions.

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[92] 1 dekatherm is equal to 10 therms or 1 MMBtu.

Table V-32 and Table V-33 below present the Normal Year Throughput forecasts for the Maine Division and New Hampshire Division, respectively. Normal Year Throughput for the Maine Division is projected to grow by about 1.9% annually over the forecast period. Normal Year Throughput for the New Hampshire Division is projected to grow by 0.3% annually over the forecast period.

Table V-32: Normal Year Throughput (Dth) – Maine Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2022/23	118,674,404	11,861,348	9,784	144,278	12,015,410
2023/24	121,559,049	12,163,093	10,051	147,948	12,321,092
2024/25	123,629,877	12,370,682	10,051	150,473	12,531,206
2025/26	125,737,178	12,582,003	10,051	153,044	12,745,098
2026/27	127,831,014	12,791,891	10,051	155,597	12,957,539
CAGR	1.9%	1.9%	0.7%	1.9%	1.9%

Table V-33: Normal Year Throughput (Dth) – New Hampshire Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2022/23	91,774,346	9,206,820	1,782	87,083	9,295,685
2023/24	91,319,553	9,139,641	1,839	86,448	9,227,929
2024/25	92,097,530	9,217,137	1,839	87,181	9,306,158
2025/26	92,622,939	9,269,666	1,839	87,678	9,359,183
2026/27	92,995,660	9,306,587	1,839	88,027	9,396,453
CAGR	0.3%	0.3%	0.8%	0.3%	0.3%

E. Energy Efficiency Impact on Demand Forecast

Incremental energy efficiency savings expected over the planning period from programs operated by Efficiency Maine Trust in Maine and Company programs offered under the NHSaves banner in New Hampshire are documented for Residential customers and C&I customers in the Customer Segment Model section for each Division. To show the impact of energy efficiency savings on the Normal Year Throughput forecasts, tables were built to simulate the projected Energy Efficiency savings over the planning period. In addition to the energy savings at the customer's location, energy efficiency also avoids lost and unaccounted for gas associated with the avoided consumption, since the Company would not need to receive gas at its city gates and deliver that gas to customer locations.

As Table V-34 shows, in the absence of energy efficiency efforts, the Normal Year Throughput forecast in Maine would be higher by approximately 210,000 Dth in 2026/27, the final year of the planning horizon, and the growth rate over the period would be 2.3% rather than the expected 1.9%. In total, Normal Year Throughput in Maine is expected to be lower by approximately 590,000 Dth over the planning period due to energy efficiency savings. Similarly, Table V-35 shows that in New Hampshire in the absence of the expected efficiency savings the Normal Year Throughput forecast in 2026/27, the final year of the planning horizon, would be higher by approximately 170,000 Dth, and the growth rate over the planning period would have been 0.7 rather than the expected 0.3%. Normal Year Throughput in New Hampshire is expected to be lower by approximately 450,000 Dth over the planning period due to energy efficiency savings.

Table V-34: Energy Efficiency Impact on Normal Year Throughput (Dth) – Maine Division

Gas Year	Normal Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Normal Year Tput w/out EE Savings
2022/23	12,015,410	-1,069	-18,967	-244	-20,280	12,035,690
2023/24	12,321,092	-5,781	-67,747	-894	-74,422	12,395,515
2024/25	12,531,206	-10,484	-107,973	-1,441	-119,899	12,651,105
2025/26	12,745,098	-15,185	-148,067	-1,986	-165,238	12,910,336
2026/27	12,957,539	-19,887	-188,161	-2,531	-210,578	13,168,117
CAGR	1.9%	107.7%	77.5%	79.5%	79.5%	2.3%
PERIOD					-590,417	

Table V-35: Energy Efficiency Impact on Normal Year Throughput (Dth) – New Hampshire Division

Gas Year	Normal Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Normal Year Tput w/out EE Savings
2022/23	9,295,685	-3,170	-7,599	-102	-10,871	9,306,556
2023/24	9,227,929	-17,410	-32,564	-473	-50,446	9,278,375
2024/25	9,306,158	-31,737	-57,702	-846	-90,285	9,396,442
2025/26	9,359,183	-46,064	-82,839	-1,219	-130,123	9,489,306
2026/27	9,396,453	-60,391	-107,977	-1,593	-169,961	9,566,414
CAGR	0.3%	108.9%	94.2%	98.8%	98.8%	0.7%
PERIOD					-451,685	

Taken together, as shown in Table V-36, Company-wide expected energy efficiency savings are expected to reduce normal weather throughput requirements by approximately 1.0 Bcf over the 5-year planning horizon. Approximately three-quarters of expected savings are from the C&I sector.

Table V-36: Energy Efficiency Impact on Normal Year Throughput (Dth) – Northern Utilities, Inc.

Gas Year	Normal Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Normal Year Tput w/out EE Savings
2022/23	21,311,096	-4,238	-26,567	-346	-31,151	21,342,246
2023/24	21,549,021	-23,191	-100,311	-1,367	-124,869	21,673,890
2024/25	21,837,364	-42,221	-165,675	-2,287	-210,183	22,047,547
2025/26	22,104,281	-61,250	-230,906	-3,205	-295,361	22,399,642
2026/27	22,353,992	-80,278	-296,138	-4,123	-380,539	22,734,531
CAGR	1.2%	108.6%	82.7%	85.9%	87.0%	1.6%
PERIOD					-1,042,102	

VI. Planning Load Forecast

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern's use of a 30 year weather history is comparable to peer natural gas LDCs; Northern used a 1-in-30 year design planning standard for both design year and design day, which is on the low side (less extreme criteria) relative to peer natural gas LDCs.*
- *Changes to the Northern's Retail Choice tariffs have resulted in significant consistency in both the Maine and New Hampshire Divisions and critically, have stabilized the Company's Planning Load obligations.*
- *Northern's Planning Load is projected to grow at a rate of 1.1% over the 5-year planning period, with Design Day Planning Load approaching nearly 150,000 Dth at the end of the period (2026/27).*

A. Introduction

Section VI presents Northern's Planning Load forecasts. Determining Planning Load is the primary objective of the demand forecasting process and the planning load forecast is the primary input to the resource planning process. Conceptually, although the numbers are the same, demand is viewed primarily from the perspective of understanding customer usage while load is viewed from the perspective of understanding supply requirements that must be served to meet customer demand. The demand forecast is adjusted in two fundamental ways in order to establish the Planning Load forecast. First, design standard weather conditions are established and then applied to the demand forecasts to establish design condition forecasts. Second, the projected loads of Capacity Exempt customers are removed, leaving the loads of customers for whom the Company plans.

This IRP uses the definitions listed in Table VI-1 with regard to design standard criteria and to distinguish among customer loads in terms of their capacity assignment status and contributions to planning load.

Table VI-1: Planning Load and Capacity Assignment Terminology

Term	Definition
Design Planning Standard	Extreme cold weather conditions with a defined likelihood of occurrence during which customer demands are expected to be at their highest levels. Northern plans to a design standard with a 1 in 30 year (1:30) likelihood of occurrence for both Design Year and Design Day.
Design Throughput	Estimated Throughput under Design weather conditions for Design Year and Design Day
Cold Snap	The coldest weather expected during a 10-day period. The Design Year forecast includes a Design Cold Snap and a Design Day
Sales Service Load	Load of Sales Service customers who the Company supplies directly
Transportation Load	Load of Transportation Service customers who are supplied by retail marketers
Capacity Assigned Load	Load of Transportation customers who are subject to Capacity Assignment under the Delivery Service Terms and Conditions
Capacity Exempt Load	Load of certain Transportation customers who are not subject to Capacity Assignment under the Delivery Service Terms and Conditions
Planning Load (PL)	Throughput associated with Sales Service Load and Capacity Assigned Load. Equals Total Throughput less Capacity Exempt Load grossed up for Company Gas Allowance, which adjusts for measurement at the gate station.

The Integrated Resource Plan addresses planning for the supply requirements of customers who rely on the Company for reliable and reasonably priced supply or for resources they can use to access such supply directly (through a retail supplier). The Company pursues Energy Efficiency in order to reduce supply requirements. Supply resources typically include upstream pipeline transportation service, underground storage service and on-system LNG production, all of which require significant long-term commitments. Supplies delivered by others are also be purchased at inlets to the Company's system, although as detailed in the Regional Market Overview portion of Section III, such supplies are subject to erratic pricing and uncertain availability. The Company does not plan for customers, who have availed themselves of provisions of the Company's Delivery Service Tariffs that allow for capacity exempt status.

The Planning Load forecast reflects the gas usage of those customers to whom Northern expects to provide supply or assign capacity under design weather conditions. Planning Load forecasts were created for Design Year and Design Day conditions for both the Maine Division and the New Hampshire

Division.[93] Planning Load is the measure Northern uses to assess the adequacy of its long-term resource portfolio.

The remainder of this Planning Load Forecast section is organized as follows:

Part B, Planning Standards and Design Weather, reviews Northern's design condition planning standards, including a survey of regional LDCs, and presents the normal and design weather assumptions used in the forecasting process;

Part C, Design Year Throughput Forecast, describes Northern's Design Year planning standard and the calibration of the Customer Segment models to Design Year conditions and presents projected Design Year Throughput for each division;

Part D, Design Day Throughput Forecast, describes Northern's Design Day planning standard and the calculation of the Design Day Throughput forecast and presents projected Design Day Throughput for each division;

Part E, Overview of Capacity Assignment, summarizes the capacity assignment rules in Northern's Delivery Service Tariffs and their impact on planning in order to provide context for the Planning Load calculations;

Part F, Planning Load Forecasts, presents the Planning Load requirements under design conditions.

B. Planning Standards and Design Weather

Northern needs to be prepared to provide supply to customers during extremely cold weather conditions. In projecting customer requirements under extreme weather conditions, the Company applies its design planning standards. Design standards define how extreme are the weather conditions under which the Company plans its resources to meet. The development of design condition forecasts begins with establishing design planning criteria or standards. Northern developed this Integrated Resource Plan using a design standard of 1-in-30 years. That is, Northern's design forecasts are meant to establish supply requirements sufficient to meet the coldest conditions expected to occur during a 30 year period.[94]

Given the trend of temperature warming reviewed in the Climate Change portion in the Customer Segment Forecasts portion of the Demand Forecast Section, the length of the historical period of weather data used to calculate design condition weather can impact the design forecasts. As discussed in the Climate Change subsection, Northern chose to use a 30 year history of weather data in establishing its

93 Planning Load forecasts under Normal conditions were also prepared, but are not presented.

94 In the Company's previous IRP, a 1-in-30 year standard was used, comparatively to the previous IRP submissions which utilized a 1-in-33 year standard. The impact between 1-in-33 and 1-in30 is small, and the change allows the Company to maintain a common standard with its affiliate Fitchburg Gas and Electric Light Company.

normal and design weather data, covering the gas years of 1991/92 through 2020/21. The 30 year period was determined to reasonably balance concerns over the warming trend by not relying on weather observations taken very long ago when temperatures were generally colder with concerns of maintaining a long enough history to allow for sufficient variation in weather that reflects conditions the Company may face.

In order to assess whether Northern's weather history and planning standards are comparable to other gas LDCs in the region, Northern reviewed recent Integrated Resource Plans / Forecast and Supply Plans submitted by other LDCs in Massachusetts and New Hampshire.[95] In terms of weather history, the periods relied upon for planning range from 20 years to over 50 years, and the average period, excluding Northern and Northern's affiliate Fitchburg, is 32.2 years. Thus, Northern's use of a 30 year history is comparable to other gas LDCs in the region. Design standards of neighboring LDCs range from 1-in-30 years to 1-in-44 years for design year and from 1-in-30 years to 1-in-50-years for design day. Thus, Northern's use of the 1-in-30 year standard is comparable to other LDCs in the region while also less likely to overstate the need for design condition resources.

Table VI-2: Weather Data History and Design Planning Standards in recent IRP Forecasts

Gas LDC	Docket	Filing Date	Weather History	Design Winter Standard	Design Day Standard
Eversource Gas of MA (former Bay State Gas)	DPU 21-118	Nov 2, 2021	53 Years	1:33	1:33
Berkshire Gas Company	DPU 22-148	Nov 18, 2022	30 Years	1:30	1:30
Eversource (Nstar)	DPU 22-86	Jul 21, 2022	20 Years	1:33	1:50
Liberty Utilities (Energy North)	DG 22-064	Oct 3, 2022	30 Years	1:44	1:44
Liberty Utilities (NE Gas)	DPU 22-129	Oct 3, 2022	20 Years	1:35	1:35
National Grid (Boston Gas)	DPU 22-149	Nov 1, 2022	40 Years	1:34.4	1:47.9
Fitchburg Gas and Electric	DPU 23-25	Jan 31, 2023	30 Years	1:30	1:30
Northern Utilities, Inc.	DG 19-126/ 2019-00123	Jul 2019	30 Years	1:30	1:30

95 No LDCs in Maine other than Northern submit IRPs.

C. Design Year Throughput Forecast

In addition to developing a Normal Year Throughput forecast, Northern developed forecasts of Throughput under extreme weather conditions, referred to as “Design Year” and “Design Day” forecasts.

While the Normal Year Throughput forecast is based on normal weather conditions, the Company maintains design planning standards of 1-in-30 year probably of occurrence for both design year and design day. The Design Year Throughput forecast was developed to determine the total load on the system that needs to be served during an extremely cold year. To estimate forecast throughput under design weather conditions, the Customer Segment Models and Company Use forecasts were re-calculated using weather data that reflects design conditions.

The Company’s normal and design planning standard effective degree-day (EDD) data are based on analyses of historical EDD data for the Maine Division (measured at the Portland, Maine weather station PWM, located at the Portland International Jetport) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station PSM, located at Pease International Tradeport). The Normal Year EDD was determined to be 7,401 EDD for Maine and 6,955 EDD for New Hampshire. Normal Year EDD were calculated by summing the 30 year average billing cycle EDD for each month using data from November 1, 1991 to October 31, 2021, the most recent 30 gas years of weather data available. The 30 year monthly averages, seasonal and total annual EDD for both Divisions are shown in Table VI-3 below.

Table VI-3: Normal Year and Design Year Billing Cycle Monthly EDD

	Maine Division		New Hampshire Division	
Month	Normal Year	Design Year	Normal Year	Design Year
Nov	655	737	611	693
Dec	990	1,114	947	1,074
Jan	1,273	1,432	1,225	1,390
Feb	1,318	1,483	1,268	1,439
Mar	1,121	1,261	1,074	1,218
Apr	862	862	808	808
May	521	521	463	463
Jun	233	233	194	194
Jul	43	43	31	31
Aug	12	12	8	8
Sep	65	65	53	53
Oct	308	308	273	273
Winter	5,357	6,028	5,125	5,814
Summer	2,044	2,044	1,830	1,830
Total	7,401	8,072	6,955	7,644

The Design Year EDD represents extreme winter conditions with a statistically defined probability of occurring once in 30 years. The Design Year EDD was used to develop a forecast of Design Year Throughput to estimate the level of consumption during an abnormally cold year. The Design Year EDD was determined to be 8,072 EDD for Maine and 7,644 EDD for New Hampshire. The Company's Design Year EDD reflects design conditions of 1-in-30 year frequency of occurrence during the winter period (November through March) and normal weather for the summer months (April through October). The statistical probability associated with the design standard was applied to the winter period EDD. Design winter EDD were calculated by first summing the billing cycle EDD for each winter from 1991/92 through 2020/21 (i.e., the most recent 30 gas years of data available at the time of analysis). The 30 year average and standard deviation of the winter EDD was then calculated and used to calculate the winter EDD associated with a 1-in-30 year probability of occurrence. The design winter EDD were then allocated to the winter months by multiplying the normal EDD for each winter month by an adjustment factor equal to the design winter EDD divided by normal winter EDD. The Design Year monthly, seasonal and total annual EDD for both Divisions are shown above in Table VI-3.

To determine the throughput associated with Design Year weather in each Division, the Company separately forecasted the Customer Segment and Company Use models containing EDD independent variables (i.e., Residential use per customer, C&I LLF use per customer, C&I HLF use per customer, and Company Use) using the Design EDD in the forecast period. The Design Year Customer Segment forecast results by Division were reduced by projected energy efficiency savings to establish Design Year net customer segment demand. Note that design condition energy efficiency savings are expected to be higher than normal condition energy efficiency savings especially for those customers that are seasonally dependent for heating.

The Maine Division customer segment net demand forecasts under design conditions are provided below in Table VI-4 for Residential customers, Table VI-5 for C&I customers and Table VI-6 for the combined Maine Division customer segment net demand.

Table VI-4: Design Residential Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2022/23	18,903,756	-11,143	18,892,613
2023/24	19,448,271	-61,979	19,386,292
2024/25	19,688,298	-112,717	19,575,580
2025/26	19,929,334	-163,439	19,765,895
2026/27	20,170,844	-214,165	19,956,679
CAGR	1.6%	109.4%	1.4%

Table VI-5: Design C&I Customer Segment Net Demand (Th) - Maine Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2022/23	78,962,818	27,306,739	-193,720	106,075,837
2023/24	81,371,434	27,907,161	-706,956	108,571,639
2024/25	83,756,932	27,881,102	-1,128,130	110,509,904
2025/26	86,227,145	27,808,052	-1,547,466	112,487,731
2026/27	88,648,984	27,766,203	-1,966,426	114,448,761
CAGR	2.9%	0.4%	78.5%	1.9%

Table VI-6: Design Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Design Net Demand	C&I Design Net Demand	Division Design Net Demand
2022/23	18,892,613	106,075,837	124,968,450
2023/24	19,386,292	108,571,639	127,957,931
2024/25	19,575,580	110,509,904	130,085,484
2025/26	19,765,895	112,487,731	132,253,627
2026/27	19,956,679	114,448,761	134,405,440
CAGR	1.4%	1.9%	1.8%

To produce the Design Year Throughput forecast, the design customer segment net demand was calendarized, converted to Dth, and design Company Use and lost and unaccounted for gas was added, similar to the process used to develop the Normal Year Throughput forecast. The Maine Division Design Year Throughput forecast is provided in Table VI-7.

Table VI-7: Design Year Throughput (Dth) – Maine Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2022/23	124,968,450	12,497,901	10,472	152,021	12,660,394
2023/24	127,957,931	12,811,101	10,907	155,831	12,977,839
2024/25	130,085,484	13,024,425	10,907	158,425	13,193,758
2025/26	132,253,627	13,241,903	10,907	161,071	13,413,881
2026/27	134,405,440	13,457,663	10,907	163,695	13,632,265
CAGR	1.8%	1.9%	1.0%	1.9%	1.9%

The customer segment net demand forecasts under design conditions for the New Hampshire Division are provided below in Table VI-8 for Residential customers, Table VI-9 for C&I customers and Table VI-10 for the combined New Hampshire Division customer segment net demand.

Table VI-8: Design Residential Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2022/23	22,794,341	-33,144	22,761,197
2023/24	23,123,737	-187,604	22,936,132
2024/25	23,673,599	-343,018	23,330,580
2025/26	24,228,726	-498,432	23,730,294
2026/27	24,783,780	-653,846	24,129,934
CAGR	2.1%	110.8%	1.5%

Table VI-9: Design C&I Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2022/23	35,528,529	38,027,391	-77,245	73,478,675
2023/24	35,279,450	38,142,768	-337,399	73,084,819
2024/25	35,613,123	38,490,790	-599,306	73,504,606
2025/26	35,968,041	38,561,779	-861,232	73,668,589
2026/27	36,323,700	38,479,429	-1,123,235	73,679,894
CAGR	0.6%	0.3%	95.3%	0.1%

Table VI-10: Design Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Design Net Demand	C&I Design Net Demand	Division Design Net Demand
2022/23	22,761,197	73,478,675	96,239,872
2023/24	22,936,132	73,084,819	96,020,951
2024/25	23,330,580	73,504,606	96,835,187
2025/26	23,730,294	73,668,589	97,398,882
2026/27	24,129,934	73,679,894	97,809,828
CAGR	1.5%	0.1%	0.4%

To produce the Design Year Throughput forecast, the design customer segment net demand was calendarized, converted to Dth, and design Company Use and lost and unaccounted for gas was added, similar to the process used to develop the Normal Year Throughput forecast. The New Hampshire Division Design Year Throughput forecast is provided in Table VI-11.

Table VI-11: Design Year Throughput (Dth) – New Hampshire Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2022/23	96,239,872	9,654,814	2,016	91,321	9,748,151
2023/24	96,020,951	9,614,697	2,016	90,941	9,707,654
2024/25	96,835,187	9,695,852	2,016	91,709	9,789,578
2025/26	97,398,882	9,752,246	2,016	92,242	9,846,505
2026/27	97,809,828	9,793,028	2,016	92,628	9,887,673
CAGR	0.4%	0.4%	0.0%	0.4%	0.4%

Lastly, since Northern is a single company that manages a single portfolio, the throughput forecast for the two divisions are summed to yield the Company level Design Year Throughput, as shown in Table VI-12.

Table VI-12: Design Year Throughput (Dth) – Northern Utilities, Inc.

Gas Year	Company Net Demand (Th)	Company Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2022/23	221,208,322	22,152,715	12,489	243,342	22,408,545
2023/24	223,978,882	22,425,798	12,924	246,772	22,685,493
2024/25	226,920,671	22,720,278	12,924	250,134	22,983,336
2025/26	229,652,509	22,994,149	12,924	253,313	23,260,386
2026/27	232,215,268	23,250,691	12,924	256,323	23,519,938
CAGR	1.2%	1.2%	0.9%	1.3%	1.2%

Table VI-13 presents the design condition version of Table IV-36 from the Demand Forecast section, which shows the impact of expected energy efficiency savings on Design Year Throughput. Approximately three-quarters of expected savings are from the C&I sector. Taken together, expected energy efficiency savings in both divisions are expected to reduce design weather throughput by more than 1.0 Bcf over the 5-year planning horizon.

Table VI-13: Energy Efficiency Impact on Design Year Throughput (Dth) – Northern Utilities, Inc.

Gas Year	Design Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Design Year Tput w/out EE Savings
2022/23	22,408,545	-4,429	-27,096	-354	-31,879	22,440,424
2023/24	22,685,493	-24,958	-104,436	-1,432	-130,826	22,816,319
2024/25	22,983,336	-45,574	-172,744	-2,401	-220,718	23,204,054
2025/26	23,260,386	-66,187	-240,870	-3,367	-310,424	23,570,810
2026/27	23,519,938	-86,801	-308,966	-4,333	-400,100	23,920,038
CAGR	1.2%	110.4%	83.8%	87.1%	88.2%	1.6%
PERIOD					-1,093,947	

D. Design Day Throughput

The Design Day planning standard represents extreme weather conditions on a single day that have a statistically defined probability of occurring on a very infrequent basis. The Design standard Peak Day EDD was used to develop a forecast of Design Day Throughput, which is the amount of gas expected to be consumed on Northern's system during the coldest day of the year under the design standard.

The Design Day effective degree-days using Northern's 1-in-30 year planning standard was determined to be 78.9 EDD for the Maine Division and 80.1 EDD for the New Hampshire Division. The Design Day EDD was calculated by first identifying the Peak Day EDD (i.e., the coldest day) for each winter from 1991/92 through 2020/21 (i.e., the most recent thirty gas years, consistent with Design Year). The 30 year average and standard deviation of the Peak Days was calculated and used to calculate the Design EDD associated with a 1-in-30 year probability of occurrence. The Normal and Design standard Peak Day EDD for both Divisions are shown in Table VI-14 below, along with the maximum recorded EDD in each division, the maximum daily Throughput recorded in each division, and the associated EDD. Note that the maximum values recorded are from February of 2023, The Company decided to include this data although not currently part of the 30 year data set used in the analysis, as it is pertinent to include and the values exceed a 1-in-100 year occurrence. Similarly, the event of single-day extreme EDDs is an occurrence that has been seen with the increasing changes in weather patterns that may be attributable to climate change. In addition to Peak Day EDD, Table VI-14 provides normal and design 10-Day Cold Snap EDD, the maximum recorded EDD over a 10-Day period and the maximum recorded Throughput over a 10-day period and the associated EDD.

Table VI-14: Normal and Design Peak Day and 10-Day Cold Snap EDD

	Maine Division		New Hampshire Division	
	Normal EDD	Design EDD (1:30)	Normal EDD	Design EDD (1:30)
Peak Day EDD	68.3	78.9	69.0	80.1
Cold Snap EDD	536.5	647.9	536.2	692.8
	Maine Division		New Hampshire Division	
	Max Recorded	Date	Max Recorded	Date
Peak Day EDD	88.7	Feb 3, 2022	81.9	Feb 3, 2022
Cold Snap EDD	655.8	thru Jan 6, 2018	646.3	thru Jan 6, 2018
	Maine Division		New Hampshire Division	
	Max Throughput	Date	Max Throughput	Date
Peak Day TPUT	89,921	Feb 3, 2022	68,526	Feb 3, 2022
Actual EDD	88.7	Feb 3, 2022	81.9	Feb 3, 2022
Cold Snap TPUT	740,691	thru Jan 6, 2018	572,851	thru Jan 6, 2018
Cold Snap EDD	655.8	thru Jan 6, 2018	646.3	thru Jan 6, 2018

To estimate the throughput associated with Design Day weather in each Division, a daily Design Day model was developed for each Division. The dependent variable in these models was historical daily throughput for the period November 1, 2021 through October 31, 2022 by Division and the independent variables included actual daily EDD and various dummy variables. For the Design Day regression models, independent variables were included for (1) days of the week; (2) winter months; (3) EDD calculated to reflect very cold temperatures (i.e., EDD base 15)[96]; and (4) the prior day's EDD. The regression models are presented in Appendix 1.

For each Division, the regression equation was adjusted by replacing the EDD-based variables with Design Day EDD, which results in Peak Day throughput for the 2022/23 winter calibrated to design standard conditions. The resulting the 2022/23 Design Day Throughput was then adjusted based on the growth in Design Year Throughput for each Division to extend the Design Day Throughput forecast throughout the planning period. This approach assumes that current load factors remain the same over the forecast period. Table VI-15 presents the Design Day Throughput forecast for the Maine Division and the New Hampshire Division and the Company totals for the forecast period.

[96] EDD are typically calculated to have a base of 65, therefore days with average temperatures greater than or equal to 65 degrees have 0 EDD, and days that are colder than 65 degrees have EDD = 65 – average temperature (adjusted for wind). Changing the base in the EDD calculation to something much less than 65 (e.g., 15) isolates very cold days since days with average temperatures greater than or equal to 15 degrees have 0 base 15 EDD and days that are colder than 15 degrees have EDD = 15 – average temperature (adjusted for wind).

Table VI-15: Design Peak Day Throughput (Dth)

Gas Year	ME Design Peak Day TPUT	ME Annual Growth Rate	NH Design Peak Day TPUT	NH Annual Growth Rate	NUI Design Peak Day TPUT
2022/23	93,738		73,079		166,816
2023/24	96,088	2.5%	72,775	-0.4%	168,863
2024/25	97,687	1.7%	73,389	0.8%	171,076
2025/26	99,316	1.7%	73,816	0.6%	173,133
2026/27	100,933	1.6%	74,125	0.4%	175,058
CAGR	1.9%		0.4%		1.2%

Since very cold Peak Days are rare, there are limited data for forecasting and limited observations for model assessment. As shown in Table VI-14, on February 3rd, 2023, Northern experienced a new system record Peak Day Throughput. Weather conditions that day were much colder than Northern's Design Day EDD. As stated previously, the respective peak EDDs that occurred are a more than 1-in-100 year occurrence, and are the highest maximum daily EDDs experienced in New Hampshire since the winter of 2003/04 and the highest daily EDD recorded in Maine throughout the history of Northern's weather database dating back to 1970. Northern applied the actual EDD values to its design day model and calculated estimated daily throughput of 99,574 Dth for Maine and 71,251 Dth for New Hampshire, for a total daily forecast of 170,825Dth. Actual throughput on February 3rd, 2023, was 89,921 Dth in the Maine Division and 68,526 Dth in the New Hampshire Division, for a daily total of 158,447 Dth. The Maine model over predicted by 9,653 Dth, or 9.6%, while the New Hampshire model over predicted by 2,725 Dth, or 3.8%. Collectively, the models were off by 7.2%. These results suggest Northern's design day throughput model is reasonably accurate, and does not show a bias towards under-predicting Design Day demand. However, it is important to acknowledge that extreme conditions like this do not lend themselves to a significant data sample set (as mentioned above) and similarly the behavior of customer usage during such events can vary wildly. For example, the Company understands anecdotally that some industrial customers may have utilized secondary heating sources to offset the high cost of gas on this extreme peak day, which if correct is a factor not reflected in the Company's model.

E. Design Year and Design Day Planning Load

As explained in Section III.B.2, certain customers are exempt from the Company's planning process and are not assigned shares of the gas supply portfolio. To account for these customers, who tend to be larger, high demand customers, the throughput forecasts are reduced by projected Capacity Exempt load to determine the Company's Planning Load. Although this section documents the Design condition Planning Load calculations, Planning Load was also calculated under Normal conditions. Please see Section III.B.2 for more background on capacity assignment and Northern's retail choice program, which is codified in the Delivery Service Tariff. Northern's planning obligations are to supply Sales Service loads and to assign proportionate shares of capacity from Northern's portfolio to retail suppliers of Capacity Assigned transportation customers.

1. Design Year Planning Load

In order to separately estimate Capacity Exempt Net Demand, the Company calculated Capacity Exempt Net Demand expressed as a percentage of C&I Total Net Demand for the last 12 months of the historical period. These monthly percentages were applied to the design forecast of C&I Total Net Demand in order to develop the design forecast of Capacity Exempt Transportation Demand. Capacity Exempt customers are eligible for Company or State (in Maine) sponsored efficiency programs and are assumed to receive a proportionate share of projected energy efficiency savings. Table VI-16 shows these calculations for the Maine Division.

Table VI-16: Design Year Capacity Exempt Net Demand (Th) – Maine Division

Gas Year	C&I Total Demand (Th)	Capacity Exempt % of C&I Demand	Capacity Exempt Design Demand	EE Savings	Capacity Exempt Net Demand
2022/23	106,269,557	28.0%	25,558,389	-58,075	25,500,314
2023/24	109,278,595	29.0%	27,544,757	-184,183	27,360,574
2024/25	111,638,034	29.0%	28,112,256	-290,387	27,821,869
2025/26	114,035,198	29.0%	28,683,217	-396,195	28,287,021
2026/27	116,415,187	29.0%	29,256,921	-501,928	28,754,993
CAGR	2.3%	0.9%	3.4%	71.5%	3.0%

Table VI-17 shows the subtraction of design Capacity Exempt Net Demand and the Company Gas Allowance required to be delivered by the retail suppliers of Capacity Exempt customers from Design Year Throughput with the result being the Design Year Planning Load for the Maine Division.

Table VI-17: Design Year Planning Load (Dth) – Maine Division

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2022/23	12,660,394	2,550,031	33,302	10,077,061
2023/24	12,977,839	2,736,057	35,732	10,206,050
2024/25	13,193,758	2,782,187	36,334	10,375,237
2025/26	13,413,881	2,828,702	36,942	10,548,237
2026/27	13,632,265	2,875,499	37,553	10,719,213
CAGR	1.9%	3.0%	3.0%	1.6%

Table VI-18 shows the calculation of design Capacity Exempt Net Demand for the New Hampshire Division. Notably, Capacity Exempt Net Demand in the two divisions is almost identical; however, Capacity Exempt load accounts for a greater portion of total C&I load in New Hampshire than in Maine.

Table VI-18: Design Year Capacity Exempt Net Demand (Th) – New Hampshire Division

Gas Year	C&I Total Demand (Th)	Capacity Exempt % of C&I Demand	Capacity Exempt Design Demand	EE Savings	Capacity Exempt Net Demand
2022/23	73,555,920	41.6%	27,585,397	-34,506	27,550,892
2023/24	73,422,218	41.3%	27,315,130	-130,860	27,184,269
2024/25	74,103,912	41.3%	27,575,050	-227,922	27,347,128
2025/26	74,529,820	41.3%	27,725,410	-324,988	27,400,422
2026/27	74,803,129	41.3%	27,817,276	-422,078	27,395,198
CAGR	0.4%	-0.2%	0.2%	87.0%	-0.1%

Table VI-19 shows the subtraction of design Capacity Exempt Net Demand and the Company Gas Allowance required to be delivered by the retail suppliers of Capacity Exempt customers from Design Year Throughput with the result being the Design Year Planning Load for the New Hampshire Division.

Table VI-19: Design Year Planning Load (Dth) – New Hampshire Division

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2022/23	9,748,151	2,755,089	26,666	6,966,396
2023/24	9,707,654	2,718,427	26,311	6,962,916
2024/25	9,789,578	2,734,713	26,469	7,028,396
2025/26	9,846,505	2,740,042	26,521	7,079,943
2026/27	9,887,673	2,739,520	26,515	7,121,637
CAGR	0.4%	-0.1%	-0.1%	0.6%

Lastly, since Northern is a single company that manages a single portfolio, the Design Year Planning Load forecasts for the two divisions are summed to yield the Company level Design Year Planning Load, as shown in Table VI-20. Recall from the presentation of Design Year EDD in the Design Year Throughput section that during the summer period, April through October, normal weather is assumed.

Table VI-20: Design Year Planning Load (Dth) – Northern Utilities, Inc.

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2022/23	22,408,545	5,305,121	59,968	17,043,456
2023/24	22,685,493	5,454,484	62,043	17,168,966
2024/25	22,983,336	5,516,900	62,803	17,403,633
2025/26	23,260,386	5,568,744	63,462	17,628,180
2026/27	23,519,938	5,615,019	64,068	17,840,850
CAGR	1.2%	1.4%	1.7%	1.1%

2. Design Day Planning Load

The same as with Design Year Planning Load, to establish the Design Day Planning Load forecast, Design Day Capacity Exempt customer load is subtracted from the Design Day Throughput forecast.

Design Day Planning Load models for each Division, similar to the Design Day Throughput models described earlier, were specified to estimate the Design Day Planning Load, which was then subtracted from Design Day Throughput to calculate Capacity Exempt load. The dependent variable in these Design Day Planning Load models was historical daily Planning Load for the period November 1, 2021 through October 31, 2022 by Division and the independent variables were identical to the independent variables used in the Design Day Throughput Models, including (1) days of the week; (2) winter months; (3) EDD calculated to reflect very cold temperatures (i.e., EDD base 15); and (4) the prior day's EDD. The regression models are presented in Appendix 1.

After the Design Day Planning Load models were specified for each Division, the regression equations were adjusted by replacing the EDD-based variables with Design Day EDD, which results in Peak Day Planning Load for the 2022/23 winter calibrated to design standard conditions. The resulting 2022/23 Design Day Planning Load was then subtracted from the 2022/23 Design Day Throughput to calculate Design Day Capacity Exempt load. Table VI-21 presents the Design Capacity Exempt Peak Day Load forecast, which reflects both net demand and the Company Gas Allowance, for the Maine Division and the New Hampshire Division and the Company totals for the forecast period.

Table VI-21: Design Capacity Exempt Peak Day Load (Dth)

Gas Year	ME Design CE Peak Day + CGA	ME Annual Growth Rate	NH Design CE Peak Day + CGA	NH Annual Growth Rate	NUI Design CE Peak Day + CGA
2022/23	13,339		9,605		22,944
2023/24	14,312	7.3%	9,477	-1.3%	23,789
2024/25	14,553	1.7%	9,534	0.6%	24,087
2025/26	14,796	1.7%	9,553	0.2%	24,349
2026/27	15,041	1.7%	9,551	0.0%	24,592
CAGR	3.0%		-0.1%		1.7%

The Company total forecast of Design Capacity Exempt Peak Day Load was then subtracted from the Company Design Peak Day Throughput to calculate Company Design Day Planning Load, as shown in Table VI-22.

Table VI-22: Design Peak Day Planning Load (Dth)

Gas Year	NUI Design Peak Day TPUT	NUI Design CE Peak Day + CGA	NUI Design Peak Day PL
2022/23	166,816	22,944	143,873
2023/24	168,863	23,789	145,074
2024/25	171,076	24,087	146,989
2025/26	173,133	24,349	148,784
2026/27	175,058	24,592	150,466
CAGR	1.2%	1.7%	1.1%

3. Daily Planning Load for PLEXOS®

Normal and Design daily Planning Load forecasts were prepared for the full planning period for analysis in the Plexos® program. The monthly forecasts described and summarized above were allocated to days according to the historical daily throughput pattern observed during the Gas Year 2021/22 (November 1, 2021 – October 31, 2022). In addition, adjustments were made to the daily distribution of monthly Planning Load during the months of January. First, a daily pattern of EDD was established for Januaries. The pattern distributed EDD such that the last day of January has Design Peak Day EDD, the last 10 days of January have Design Cold Snap EDD and the balance of daily January EDD are adjusted downward proportionately to match the design January EDD shown in Table VI-14. The pattern for the 10-day Cold Snap was taken from the 10 day period ended January 6, 2018, which was both the coldest (highest EDD total) 10-day period on record in both Divisions and also the period with the highest 10 consecutive day throughput on record in both Divisions, as shown on Table VI-14. The balance of the January daily EDD pattern was from January 2022. Second, base (intercept) and space (slope) factors were calculated by regressing actual daily throughput against actual daily EDD observed in the month of January 2022. The January EDD pattern was applied and the daily throughput was calculated using the base and space factors. The resulting daily throughput pattern was used to allocate the January monthly forecasts to days. Lastly, each year the calculated Design Day Planning Load was set as the daily value for January 31 each year and any residuals were allocated among the other 30 days of each January.

VII. Current Portfolio

Key Takeaways

Key takeaways in this chapter include the following:

- *Current customer funded energy efficiency programs operating in both Maine and New Hampshire deliver cost-effective energy savings, which are integrated into the Company's long-term resource plan as reductions to demand and thus Planning Load.*
- *Northern's current portfolio of long-term capacity resources provides a maximum daily quantity of 99,558 Dth of supply to Northern's system. Since Northern's last IRP was filed, Northern has added additional storage at Dawn, Ontario such that Portland XPress and Westbrook Xpress capacity are now part of the Dawn Hub Storage capacity path. Additions of Atlantic Bridge, Portland XPress, and Westbrook Xpress capacity to the portfolio have reduced, but not eliminated, Northern's reliance upon the availability of Delivered Supplies. Northern's Capacity Resources are cost effective and provide resource capability that cannot be replaced with other resources so the Company plans to renew all capacity subject to renewal during the planning period.*
- *Northern solicits for Asset Management services, peaking supply, and supplemental supplies annually in order to fill its capacity, mitigate costs to customers and minimize pipeline scheduling risk. Northern's contracting strategies for physical supply provide price risk management benefits by minimizing exposure to daily price indices, maintaining sufficient underground storage and making forward NYMEX price locks in advance of the winter.*

A. Introduction

Section VII provides an overview of Northern's current portfolio, including a review of current Energy Efficiency programs, an overview of the Company's current long-term capacity resources, narrative descriptions of each capacity resource by path, and a brief discussion of the Company's supply procurement practices.

As supporting information, Appendix 2 provides capacity path diagrams and tabular lists of contract detail for each path that depict how Northern has combined its pipeline transportation and underground storage contracts, along with the Eversource Gas Company of Massachusetts ("EGMA") Exchange Agreement (formerly known as the Bay State Exchange Agreement) and Granite capacity, in order to move natural gas supplies from various supply sources to Northern's distribution system. The capacity path details provided in Appendix 2 include basic contract information such as product (transportation, storage or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point. To supplement the Appendix 2 capacity path diagrams, Appendix 3 provides a set of maps showing each capacity path from supply source to the Company's system as well as individual maps of each pipeline.

The remainder of the Current Portfolio section is organized as follows:

Part B, Planned Energy Efficiency Resources, provides references program level savings data, provided in Appendix 4, for the Energy Efficiency programs expected to be implemented under Efficiency Maine's latest Triennial Plan in the Maine Division and by Northern under the Three-Year EERS Plan in the New Hampshire Division;

Part C, Long-Term Supply Resources, summarizes Northern's long-term capacity under contract by resource type and the supply sources accessed, including contract renewal dates, and provides resource narratives that describe each path in more detail;

Lastly, Part D, Short-Term Supply and Price Risk Management, provides a summary describing how the Company uses its long-term resources to purchase supply and mitigate cost to customers from year to year, including results of asset management arrangements, and describes the Company's price risk management efforts.

B. Planned Energy Efficiency Savings

Please see Section III.B.1. for general background on the respective Energy Efficiency programs in each state.

1. Maine Energy Efficiency

The Energy Efficiency savings modeled for the Maine Division reflect Efficiency Maine's March 1, 2023, filing providing its Annual Update in the docket pertaining to approval of its Fifth Triennial Plan for the Fiscal Years of 2023-2025.[97] Appendix 4, Energy Efficiency Program Reports, presents the Trust's Summary of Program Funding for fiscal years 2023 through 2025, truncated to show projected costs, savings and other metrics by program only for natural gas. The tables in Appendix 4 also separately subtotal Residential and C&I savings. Northern reviewed natural gas LDC assessments provided on Table D-1 from Efficiency Maine's Annual Reports for fiscal years 2021 through 2023. Northern's average assessment over those three years was 57.5 percent of the Trust's annual budget, as shown on page 5 of Appendix 4. Northern adjusted the statewide totals by this percentage to determine expected savings for its customers that are modeled as demand reductions in the IRP.

[97] As required pursuant to 2021-00380, Order Approving Stipulation (May 17, 2022).

2. New Hampshire Energy Efficiency

The Energy Efficiency savings modeled for the New Hampshire Division reflect the currently approved 2023 PLAN, per the March 1, 2022, Compliance Filing, as approved in NHPUC Docket No. DE 20-092.[98] Page 6 of Appendix 4 presents the program costs and savings for 2023. The Company extended these projected annual savings forward throughout the planning period.

C. Long-Term Capacity Resources

Northern has acquired a portfolio of long-term capacity resources for the purpose of satisfying its Planning Load requirements. The portfolio includes pipeline transportation capacity, underground storage capacity that has been combined with pipeline capacity in order to deliver withdrawn storage to the Company's system and an on-system LNG storage and vaporization facility. As discussed further in Section VIII, Resource Balance, the current portfolio does not satisfy Northern's Planning Load requirements, and so Northern supplements its long-term capacity portfolio with short-term supplies delivered by others to its distribution system or to Granite interconnects ("Delivered Service" or "Delivered Supply").

1. Overview of Capacity Portfolio

Northern accesses wholesale natural gas supplies via the following entry points to Northern's distribution system:

- Granite State Gas Transmission ("Granite" or "GSGT") provides transportation capacity that links upstream capacity on PNGTS, TGP and MN US to Northern city gates along the Granite system
- Interconnections between Portland Natural Gas Transmission System ("PNGTS") and Granite, located in Westbrook, Maine, Eliot, Maine, South Berwick, Maine, and Newington, New Hampshire
- Interconnections between Tennessee Gas Pipeline Company ("Tennessee" or "TGP") and Granite, located in Haverhill, Massachusetts and Salem, New Hampshire
- Interconnection between Maritimes & Northeast U.S. ("Maritimes" or "MN U.S.") and Granite Located in Westbrook, Maine, South Berwick, Maine, or Maritimes' interconnect with Northern's city gate located in Lewiston, Maine
- On-System LNG storage and production facility located in Lewiston, Maine
- Deliveries made by EGMA to Northern's system under the EGMA Exchange Agreement, under which Northern delivers supplies to EGMA's Tennessee or Algonquin city gates and EGMA delivers supplies to Northern's city gates

[98] DE 20-092, Order No. 26,621 ("Order on the 2022-2023 New Hampshire Statewide Energy Efficiency Plan")

Northern's long-term resource portfolio is summarized below in Table VII-1, which lists the resources by capacity path as Northern deploys them, the respective MDQ of each path by season, resource type and form of capacity assignment to retail marketers under the Delivery Service tariffs.

Table VII-1: Northern Long-Term Resources by Capacity Path (MDQ in Dth)

November 1, 2023 Capacity Paths	Resource Type	Max Daily Quantity	Method of Assignment	Status
Iroquois Receipts Path	Pipeline	6,434	Company-managed	Existing
Tennessee Niagara Capacity	Pipeline	2,327	Capacity Release	Existing
Tennessee Long-haul Capacity	Pipeline	13,109	Capacity Release	Existing
Algonquin Receipts Path	Pipeline	1,251	Company-managed	Existing
Atlantic Bridge Capacity	Pipeline	7,500	Capacity Release	Existing
Tennessee Firm Storage Capacity	Storage	2,644	Capacity Release	Existing
Dawn Storage Path	Storage	59,793	Capacity Release	Existing
Lewiston On-System LNG Plant	Peaking	6,500	Company-managed	Existing
Long-Term Capacity		**99,558**		**Existing**

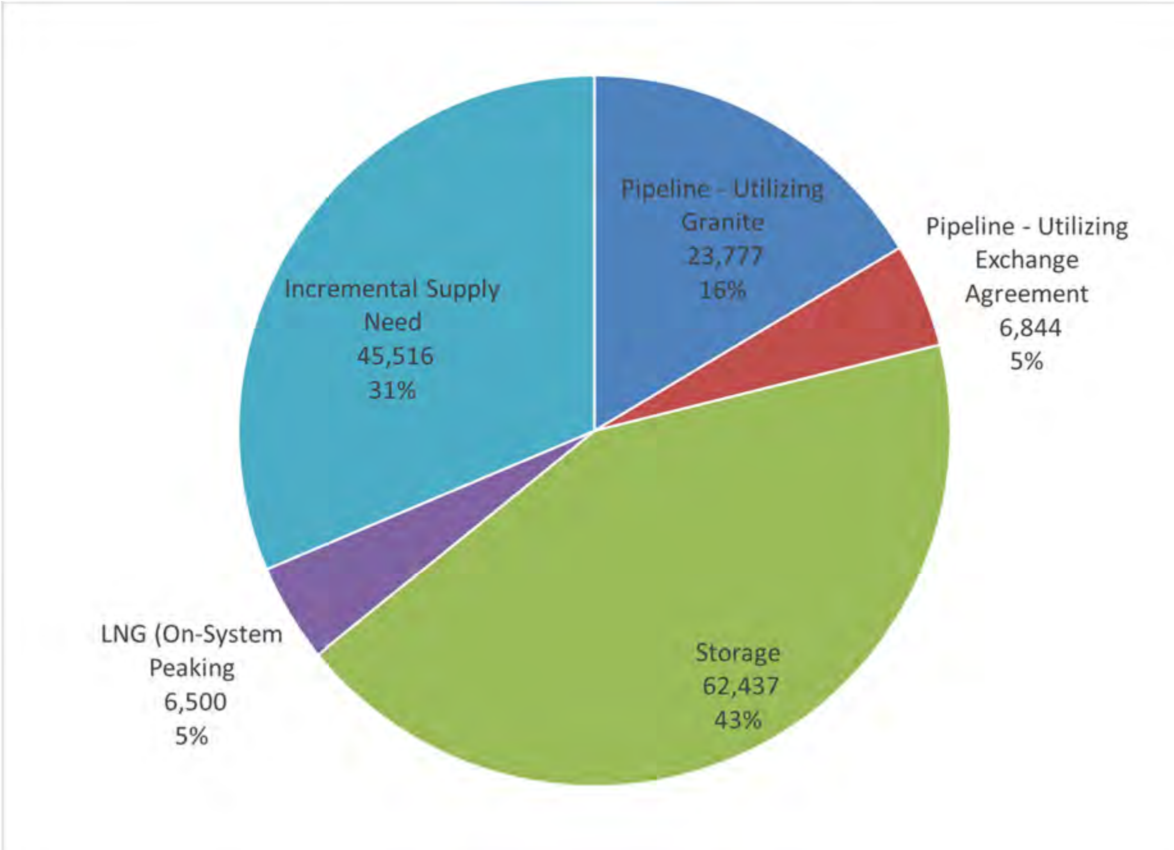
Resource narratives for each long-term resource path listed in Table VII-1 are provided below. Although not listed in the table above, Granite capacity is essential to Northern's portfolio and is used to deliver most of the capacity paths above. Also not listed above is the EGMA Exchange Agreement, which facilitates in kind deliveries by EGMA to Northern in exchange for supplies Northern delivers to EGMA. Narratives for Granite and the EGMA Exchange Agreement are also provided below.

Northern's long-term resources are supplemented with Delivered Supplies that are typically contracted for on a short-term basis in order to meet Northern's winter period sales service load requirements. Delivered Supplies are not assigned to retail marketers under the Delivery Tariffs, so Northern considers only the requirements of Sales Service customers when evaluating its need for Delivered Supplies. The actual amount of Delivered Supplies varies and is projected year to year. The additions of the Portland Xpress and the Westbrook Xpress capacity have eliminated the need for delivered baseload supply, however, Northern does still require Delivered Peaking. For the upcoming winter of 2023/24, Northern's long-term portfolio will need to be supplemented with Delivered Peaking supply of approximately 45,516 Dth per day in order to meet projected design day demands. Northern will purchase the majority of this incremental supply need to meet its Sale Service obligations. Retail marketers will make up the balance to meet the requirements of Delivery Service customers. The 45,516 Dth per Day of projected Delivered Supplies comprise 31% of the Company's projected design day of 145,074 Dth for the upcoming 2023/24 Winter Period. Clearly, the MDQ of these delivered supplies is very significant relative to the MDQ of Northern's long-term resources. The addition of Atlantic Bridge and Portland XPress Capacity Paths for the 2020/21 Winter Period and of the Westbrook XPress Capacity Path for the 2022/23 Winter Period reduced the Company's need for Delivered Supplies. Table VII-2 provides a summary of Northern's 2023/24 Winter Period portfolio by resource type, including Incremental Supply Need, which will be fulfilled with Delivered Supply. Figure VII-1 provides this information in graphical form.

Table VII-2: Current Northern 2023/24 Winter Period Portfolio by Resource Type

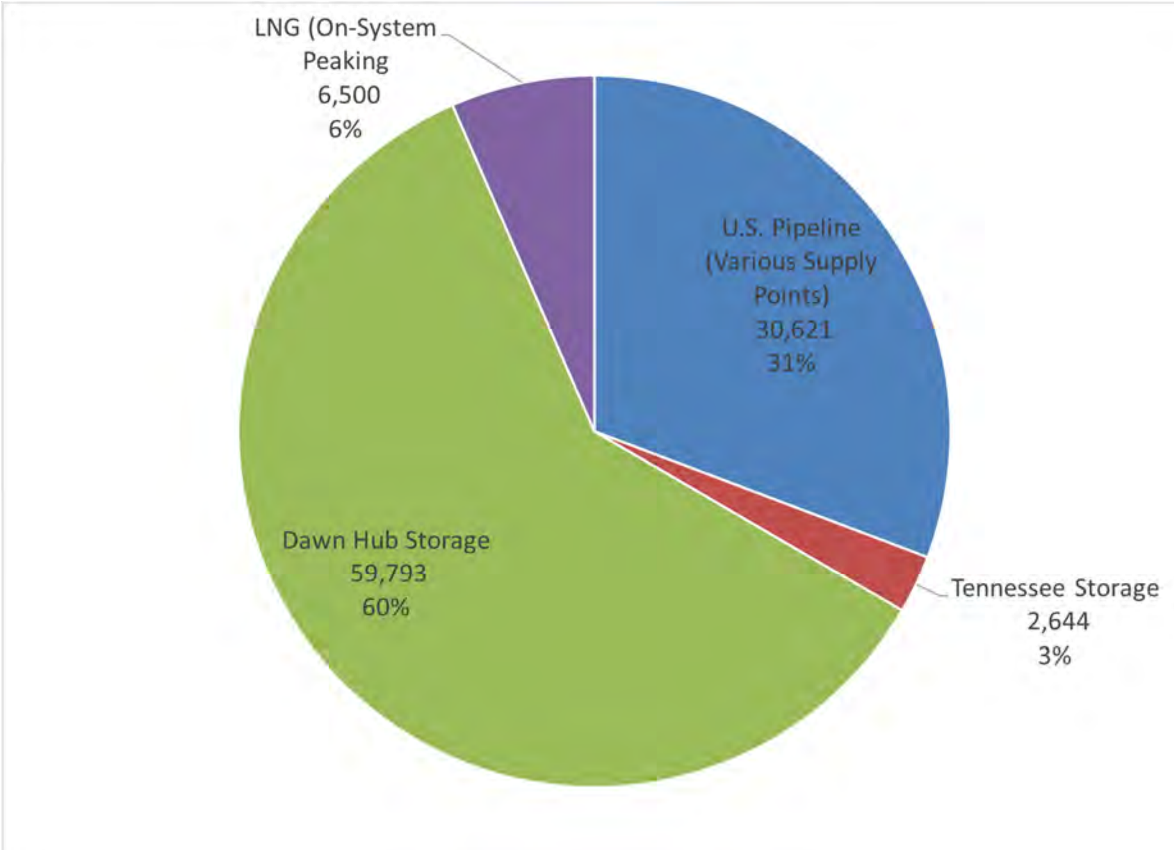
Resource Type	MDQ (Dth)
Pipeline - Utilizing Granite	23,777
Pipeline - Utilizing Exchange Agreement	6,844
Storage	62,437
LNG (On-System Peaking	6,500
Incremental Supply Need	45,516
Total Capacity Resources	145,074

Figure VII-1: Current Northern 2023/24 Winter Period Portfolio by Resource Type



Northern seeks to maintain diversity among its long-term resources in terms of delivering upstream pipelines and supply sources. Dawn Hub Storage access Northern's system via PNGTS. Beginning April 1, 2023, Northern increased its Dawn Hub Storage contract with Enbridge to have a sufficient withdrawal volume to be able to fill all of its downstream, Enbridge, TCPL and PNGTS capacity, including the PXP and WXP expansion contracts. Current U.S. Pipeline and Tennessee Storage supplies access Northern's system via TGP or the EGMA Exchange Agreement. The acquisition of the Atlantic Bridge capacity path added new U.S. Pipeline supply, which accesses Northern's system via MN US. Northern's LNG plant is located in Lewiston, Maine on its distribution system and accesses supply via annual contracts for LNG supply and trucking. A diversified and balanced portfolio provides better reliability and flexibility than relying on a more limited number of supply sources or entry points into the distribution system. However, Northern's ability to enhance diversity has been limited by the fact that expansion projects from the south have been limited relative to expansion projects from the north. In addition, Northern must receive supplies in various points on its system in order to meet load requirements at those locations. Figure VII-2 below summarizes the diversity by supply source of Northern's current long-term portfolio for the upcoming 2023/24 gas year.

Figure VII-2: Diversity of 2023/24 Long-Term Capacity by Supply Source (Dth)



2. Existing Supply Resource Narratives

Northern Utilities' long-term capacity portfolio is comprised of transportation and underground storage capacity contracts that collectively provide reliable and diversified supply to its system in order to serve Planning Load requirements. Northern's transportation capacity includes short-haul and long-haul contracts intended to move gas to and from storage, and contracts that are aggregated into defined transportation paths.

As a reference to accompany the existing resource narratives, Table VII-3 provides a listing of Northern's long-term pipeline and underground storage , organized by capacity path, including contract end / renewal dates, and receipt and delivery zones.

Table VII-3: Pipeline Transportation and Underground Storage Contracts by Capacity Path

Capacity Path	Vendor	Contract ID	Contract End Date	Receipt Zone	Delivery Zone
Iroquois Receipts	Iroquois	181003	10/31/2024	Waddington	Wright
Iroquois Receipts	Tennessee	95196	10/31/2027	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Tennessee	41099	10/31/2027	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Algonquin	93002F	10/31/2024	Mendon, MA	Brockton, MA
TGP Niagara	Tennessee	5292	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Niagara	Tennessee	39735	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Long-haul	Tennessee	5083	10/31/2028	TGP Zone 0	TGP Zone 6
TGP Long-haul	Tennessee	5083	10/31/2028	TGP Zone L	TGP Zone 6
Algonquin Receipts	Texas Eastern	800384	10/31/2028	Leidy Storage	Lambertville, NJ
Algonquin Receipts	Algonquin	93201A1C	10/31/2024	Lambertville, NJ	Taunton, MA
TGP Firm Storage	Tennessee	5195	3/31/2025	TGP Zone 4	TGP Zone 4
TGP Firm Storage	Tennessee	5265	3/31/2025	TGP Zone 4	TGP Zone 6
Dawn Storage	Enbridge	LST155	3/31/2028	Union Dawn	Union Dawn
Dawn Storage	Enbridge	M12256	10/31/2033	Union Dawn	Parkway
Dawn Storage	Enbridge	M12296	10/31/2040	Union Dawn	Parkway
Dawn Storage	Enbridge	M12279	10/31/2037	Union Dawn	Parkway
Dawn Storage	TransCanada	57901	3/31/2033	Parkway	East Hereford
Dawn Storage	TransCanada	57055	10/31/2032	Parkway	East Hereford
Dawn Storage	TransCanada	63265	10/31/2040	Parkway	East Hereford
Dawn Storage	TransCanada	67167	10/31/2037	Parkway	East Hereford
Dawn Storage	PNGTS	208543	11/30/2032	Pittsburg, NH	Newington, NH
Dawn Storage	PNGTS	233339	10/31/2040	Pittsburg, NH	Newington, NH
Dawn Storage	PNGTS	240520	10/31/2037	Pittsburg, NH	Newington, NH
Atlantic Bridge	Algonquin	510939	2/11/2036	Ramapo/Mahwah, NJ	Beverly, MA
Atlantic Bridge	Maritimes	210363	2/11/2036	Beverly, MA	Lewiston, ME
All Capacity Paths	Granite	19-100-FT-NN	10/31/2023	NA	Northern

a) Iroquois Receipts Path

The 'Iroquois Receipts' path initiates at the Iroquois Gas Transmission ("Iroquois") interconnect with TransCanada in Waddington, New York, which delivers into Tennessee at Wright, New York. A small portion of deliveries on this path feed into Granite at the Pleasant Street interconnect with Tennessee in Haverhill, Massachusetts, while the majority feeds into the EGMA Gas system at Agawam, Massachusetts and Brockton, Massachusetts via Tennessee and Algonquin. This path utilizes the EGMA Exchange Agreement. The portion of this path that delivers into Granite is assigned via capacity release and the portion that delivers to EGMA is assigned to marketers of delivery service customers as a Company-managed resource.

b) Tennessee Niagara Capacity

Northern has entitlements on two transportation contracts on the Tennessee Gas Pipeline with primary receipts at Niagara in Zone 5 on the 200 leg, and primary deliveries to Zone 6 on the 200 leg at EGMA city gates and Pleasant Street, the interconnection with Granite in Haverhill, Massachusetts. Northern receives the deliveries on Tennessee to Pleasant Street on its corresponding firm Granite capacity for transport to Northern city gates. This path is assigned to marketers of delivery service customers via capacity release.

c) Tennessee Long-haul Capacity

Northern has one long-haul transportation contract on Tennessee Gas Pipeline, which allows Northern to deliver up to 13,155 Dth into Granite. The primary receipt points within this contract are located at the pooling points in the Gulf Zones 0 and 1 on the 100, 500, and 800 legs. Primary delivery meters on this contract are in Zone 6 on the 200 leg at Pleasant Street, Salem, and EGMA's city gates as well as in Zone 4 on the 300 leg at the injection meter for TGP's Northern Storage - FS-MA. This path is assigned to marketers of delivery service customers via capacity release.

d) Algonquin Receipts Path

Northern combines Texas Eastern Transmission Company ("TETCO") capacity with Algonquin long-haul capacity to access Leidy storage in Pennsylvania, which is a liquid supply hub. Northern's Algonquin contract includes receipt capacity at the interconnection between Algonquin and TETCO's Zone M3 at Lambertville, New Jersey and at the interconnection between Algonquin and Transcontinental Gas Pipe Line ("Transco") in Zone 6 at Centerville, New Jersey. This capacity has primary delivery rights to EGMA's Algonquin city-gate at Taunton, Massachusetts. This path utilizes the EGMA Exchange Agreement and is assigned to marketers of delivery service customers as a Company-managed resource.

e) Tennessee Firm Storage

Northern has firm underground storage entitlements on the Tennessee system in Zone 4 on the 300 leg in Pennsylvania. Northern's maximum storage quantity is 259,337 Dth, and the maximum withdrawal quantity is up to 4,243 Dth/day. The primary receipt meter in this transportation contract is the FS-MA storage withdrawal meter, and the primary delivery meter is at Pleasant Street, the interconnection between Tennessee and Granite. Northern receives this gas on its corresponding Granite capacity to make deliveries to Northern city gates. This path is assigned to marketers of delivery service customers via capacity release.

f) Dawn Storage Path

As of April 1, 2023, the Dawn Storage Path provides 6.0 Bcf of storage (previously was 4.0 BCF of storage) that can deliver up to 59,793 Dth/day, sourced from Dawn Storage during the winter or via purchases at the Dawn Hub year-round. Northern holds firm transportation capacity for this path on Enbridge, TransCanada and PNGTS, including capacity secured under C2C, PXP and WXP open seasons. The Dawn Storage Path is assigned to marketers via capacity release.

g) Lewiston On-System LNG

The Lewiston LNG facility is an important resource within Northern's portfolio. Northern relies on the Lewiston plant to produce up to 6,500 Dth per day, which corresponds to approximately two days of onsite storage. The Lewiston LNG facility offers advantages not available from other supply resources such as flexibility that cannot be attained by the pipeline deliveries since pipeline supplies require steady takes over the course of the gas day (10 am – 10 am EST). In contrast to the ratable schedule of pipeline deliveries, Northern is able to run the plant as needed so that volumes can be produced for a portion of the day or across gas days as needed. The Lewiston LNG facility does have limited on-site storage capacity, which means that most of the LNG vaporized during winter is purchased at winter prices. LNG is assigned to marketers of delivery service customers as a Company-managed resource.

h) Atlantic Bridge

Atlantic Bridge capacity is 7,500 Dth/day. Atlantic Bridge involved expanding the Algonquin pipeline system and adding compression in Weymouth, Massachusetts, in order to provide adequate pressure to deliver gas northward into Maritimes. The Algonquin capacity provides for receipts from either Millennium at Ramapo, New Jersey or Tennessee's Zone 5, 300 Leg at Mahwah, New Jersey. Northern has acquired downstream capacity on Maritimes with a primary delivery point in Lewiston, Maine. This capacity is assigned to marketers via capacity release.

i) Granite State Gas Transmission

Northern utilizes its Granite transportation capacity in order to deliver all of its transportation and underground storage supply resources with the exception of those delivered under the EGMA Exchange Agreement, which is delivered to Northern's city-gates by EGMA. Granite is an affiliate of Northern, and both are subsidiaries of Unitil Corporation. Granite operates an 87-mile pipeline, extending from Haverhill, Massachusetts, through New Hampshire to just northwest of Portland, Maine, and has no on-system storage or compressor stations.

Granite has six receipt meters. The Westbrook and South Berwick receipt meters interconnect with PNGTS and MN U.S. The Newington and Eliot receipt meters interconnect with PNGTS. The Pleasant St. and Salem St. receipt meters interconnect with Tennessee Gas Pipeline. Granite has thirty-six delivery meters on its system, each of which is a Northern city-gate. Seventeen of these meters deliver to the New Hampshire Division and nineteen deliver to the Maine Division. Northern releases portions of its Granite capacity as part of released capacity paths and also assigns portions of its Granite capacity as peaking capacity.

j) Eversource Gas of Massachusetts (EGMA) Exchange Agreement

The EGMA Exchange Agreement is an agreement under which Northern Utilities delivers its firm Tennessee and Algonquin transportation entitlements to EGMA's city gates at Agawam and Lawrence on Tennessee Gas Pipeline and Brockton and Taunton on Algonquin pipeline in exchange for deliveries from EGMA to Northern's city gates located along the Granite State pipeline. Both parties benefit from this exchange as a means of delivering supply to their respective systems without having to contract for additional firm pipeline capacity, allowing each to make the best use of assets that do not access their own distribution system. The parties have mutually agreed to base load winter volumes of 12,000 Dth/day and have the option to base load summer volumes up to 4,100 Dth/day, which are subject to adjustment as mutually agreed. Northern requires the EGMA Exchange Agreement in order to deliver portions of the Iroquois Receipts path. However, Northern may also elect to utilize the EGMA Exchange for the purpose of delivering Tennessee Long-haul or Tennessee FS-MA supply resources to EGMA in order to effectuate deliveries into the northern portion of Northern's system (deliveries via PNGTS). The Exchange Agreement has been in place since December 2008, when Unitil purchased Northern from NiSource. The Agreement does have a 180-day termination notice provision, so it could be terminated by either party. At this time, both parties deem the Exchange to be advantageous and neither has plans to terminate the agreement.

D. Short Term Supply and Price Risk Management

1. Annual Resource Acquisition

While the Company's acquisition of capacity resources is a long-term endeavor, each year the Company purchases supplies to fill the capacity and arranges for asset management services to mitigate costs for customers and to reduce pipeline scheduling risk. The Company's supply activity is explained in detail and reviewed by both the Maine and New Hampshire Public Utilities Commissions in periodic Cost of Gas filings.

The Company's supply procurement process begins with an annual sales forecast. In determining its supply requirements, the Company utilizes its latest forecasts of monthly gas supply requirements under Normal Year, Design Year and Design Day scenarios, as well as recent sendout experience from the outgoing winter period, adjustments to account for projected retail choice activity and capacity assignment requirements.

In advance of each spring, the Company conducts an annual asset management arrangement ("AMA") Request for Proposals ("RFP"). The annual RFP for asset management services is used to fill existing long term capacity, to ensure that scheduling services will be provided by experienced and reliable counterparties, and to provide revenue that offsets the cost of capacity for the benefit of customers. Prior to the recent capacity additions going into service, Northern would purchase delivered baseload supply along with the AMA RFP, but Northern no longer requires the purchase of delivered baseload supplies to satisfy requirements during the winter. The additions of new capacity replaced Delivered Baseload purchases.

Notwithstanding the additional need for peaking supply, the Company structures its AMA contracts to ensure that supply available under the portfolio will satisfy design forecast requirements to the maximum extent possible while providing an economic combination of baseload and swing supplies, and reserving sufficient flexibility to adjust volumes on a monthly or daily basis as needed. Where practical, AMAs are structured to give prospective asset managers information about how often the capacity will be unencumbered by Northern over the course of the year, for example during summer periods where assets are determined to fall outside of the economic dispatch and are therefore not needed to meet customer needs, so they can provide their best (highest value) offers for the right to manage the capacity. Table VII-4 provides a history of the revenue received under Asset Management Arrangements, which have served to reduce the cost of capacity to customers. The recently higher AMA values reflect the current

Table VII-4: History of Asset Management Revenue [REDACTED]

Year	Demand Costs	AMA Revenue	AMA Revenue as % of Demand Costs
2023-2024	$ 51,735,330	[redacted]	[redacted]
2022-2023	$ 51,735,330		
2021-2022	$ 45,161,950		
2020-2021	$ 42,223,988		
2019-2020	$ 29,315,558		
2018-2019	$ 32,868,327		
2017-2018	$ 34,959,192		
2016-2017	$ 36,373,664		
2015-2016	$ 36,565,808		
2014-2015	$ 41,234,710		
Period Average	$ 40,217,386		

In addition to the AMA purchases, the Company purchases Delivered Peaking supplies and LNG via RFPs. The Company's current long-term supply portfolio is not capable of meeting design day requirements. To ensure adequate supply during the coldest days, the Company conducts an RFP for delivered peaking supply and an RFP for LNG supply. The Company compares the Design Day and Design Year forecasts to the supplies available following the AMA RFP and from the LNG plant, and then determines how much delivered peaking supply is needed to meet forecast requirements on the coldest day and throughout the winter. These requirements are reflected in the peaking RFP and resulting contracts as the Maximum Daily Quantity (MDQ) and the Annual Contract Quantity (ACQ) or Maximum Seasonal Quantity (MSQ). When possible, RFPs for delivered peaking supply are structured to ensure availability of adequate supply to meet locational needs and provide operational flexibility, such as non-ratable, day ahead and intraday nominations that allow for increases or decreases over weekends, while limiting exposure to daily market area index pricing which can be extreme on the coldest days, when peaking supply is most likely to be needed. Northern is currently seeking a replacement for its long term peaking contract which commenced in 2019 and terminated March 2023.

Adequate LNG is purchased to fill the Company's LNG plant in Lewiston, ME. Since Northern's LNG plant has limited storage capability, Northern issues RFPs for LNG supply that are structured to provide daily refill capability sufficient to maintain the plant's planning capability of 6,500 Dth/day throughout the winter. The current LNG contract provides for delivery of up to 3 truckloads per day. Refill deliveries are received during the summer for replacement of LNG that has boiled off.

2. Price Risk Management

Northern's objective is to mitigate the risk of significant mid-Winter Period Cost of Gas increases and to provide improved price certainty for customers during the Winter Season when usage is highest, while maintaining a high level of portfolio flexibility to respond to changes in demand due to weather, retail choice and other factors.

Northern's objective is to mitigate the risk of significant mid-Winter Period Cost of Gas increases and to provide improved price certainty for customers during the Winter Season when usage is highest, while maintaining a high level of portfolio flexibility to respond to changes in demand due to weather, retail choice and other factors. The Company operated a financial hedging program on behalf of customers in both Divisions which had been in place when Unitil purchased Northern Utilities from NiSource in December 2008. The original financial hedging program was structured to purchase NYMEX futures contracts under both price-based and time-based criteria in order to stabilize prices, with sales of NYMEX contracts occurring upon futures contract expiration. After experiencing financial losses under the program, Northern redesigned the hedging program to eliminate price-based purchases of futures contracts, recognize the hedging value of physical resources such as underground storage and introduce criteria whereby purchases of futures contracts were suspended in response to high as prices rise and futures contracts that appreciated significantly would be sold before they expire. After continued losses, Northern redesigned the hedging program again to introduce out of the money call options on futures contracts instead of futures contract, with the goal of protecting against exposure to very high price increases. Options contracts had the advantage of avoiding downside price risk, such that if prices fell after options were purchased, Northern's customers would still realize the lower prices while having protection from price increases above the option strike prices, whereas purchasing futures contracts simply locked in price. After assessing different option budget levels (shares of the futures prices to apply toward option purchases), Northern consistently saw the options contracts expire worthless and proposed to suspend the hedging program in 2017 and then terminate the hedging program in 2018.

A primary reason Northern terminated its financial hedging program was that the program sought to hedge NYMEX price risk even though NYMEX prices, reflecting the Henry Hub, had been stable with a stable outlook, while basis differentials between NYMEX pricing and index prices in New England were high, growing and volatile.

Since Northern last submitted its IRP in 2019, commodity markets have changed dramatically with NYMEX prices increasing significantly heading into the 2021-2022 Winter Period. In response to the sharp increases and volatility observed during the pendency of Northern's 2021-2022 Annual Period COG filing, Northern locked in the NYMEX portion of its physical supply contracts to achieve a 70 percent hedged from further NYMEX volatility. Northern ultimately adopted the Price Risk Mitigation Plan, which is summarized below, in advance of the 2022-2023 Winter Period. During the 2022-2023 Winter Period, NYMEX prices fell steadily and are at now much closer to the low levels that were observed when the prior hedging program had been suspended. The Company plans to review its Price Risk Mitigation Plan on an ongoing basis so that it is responsive to changing market conditions.

Table VII-5: Summary of Price Risk Mitigation Plan

Goals and Objectives:	Northern's objective is to mitigate the risk of significant mid-Winter Period Cost of Gas increases and to provide improved price certainty for customers during the Winter Season when usage is highest, while maintaining a high level of portfolio flexibility to respond to changes in demand due to weather, retail choice and other factors.
Target Ratio:	Northern plans to hedge 75 percent ("Target Ratio") of November through March projected volumes against increases in NYMEX prices. The Target Volume will be determined by multiplying Northern's projected sales service volumes times the Target Ratio.
Contracting Process:	Northern plans to utilize physical gas purchases to implement NYMEX hedges, in the form of underground storage and physical gas purchases under which the NYMEX portion of the price is fixed in advance of the Winter Season The volume of physical gas purchases with fixed NYMEX pricing will be determined by subtracting underground storage deliverability from the Target Volume.
Timing:	Northern plans no changes to its current underground storage injection practices[99]. NYMEX price locks under the Plan for baseload pipeline supplies would be implemented in 4 monthly blocks during June through September and be completed prior to the update in the Winter cost of gas filings such that all fixed price supply is reflected in the final approved CGF rates.
New England Spot Price Exposure:	In addition to the changes discussed above, Northern will continue to limit exposure to daily New England spot prices, including the Algonquin city-gates and Tennessee Zone 6 daily index prices.

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

Northern provides price risk management by way of its physical procurement strategies. In the near term, as explained under Annual Resource Acquisition above, as feasible Northern structures its Delivered Supply and LNG contracts to be indexed to monthly rather than daily prices, in order to insulate customers from daily index pricing, which can become extreme particularly on very cold days when delivered peaking supplies are needed. Longer term, Northern has sought to acquire additional physical assets that allow greater access to supplies at locations where gas is plentiful and prices are competitive. For example, in 2018 Northern increased its underground storage capacity by 15 percent. in recent years and has regularly added pipeline capacity to its Capacity Portfolio that will allow for purchases are more liquid supply points such as the Dawn Hub. Northern's pending and proposed pipeline capacity, including its commitments to the Portland Xpress, Atlantic Bridge and Westbrook Xpress projects, will significantly reduce the Company's purchases of market area Delivered Supply and increase the purchases of gas at locations where gas is more plentiful and prices are more stable.[100]

Examples of the disparity in pricing among different supply points are provided in the Regional Market Overview part of Section III. See Figure III-10 and Table III-6.

[100] The pricing benefits of Northern's commitments to recent pipeline projects are in addition to the primary benefit of providing access to supply needed to reliably serve customers.

VIII. Resource Balance

Key Takeaways

Key takeaways in this chapter include the following:

- *The Long-Term Capacity Portfolio is insufficient to meet Planning Load under Normal Year, Design Year and Design Day conditions throughout the Planning Period, covering the 2023/24 through 2027/28 gas years.*
- *The Company addresses this gap for its Sales Service customers with delivered supply purchases, including baseload delivered supplies and off-system peaking supplies. Delivered supplies are purchased solely to meet the needs of Sales Service customer loads because they are not assignable the retail marketers. The Company is seeking to replace the multi-year off-system peaking supply arrangement to address the gap between the Normal Year, Design Year and Design Day Planning Load requirements and the capabilities of the Capacity Portfolio for Sales Service customer loads while the Company evaluates longer-term solutions. The Company is also monitoring the pipelines that deliver into its system for opportunities to further increase capacity resources.*

A. Introduction

Section VIII provides information showing the difference between the Planning Load forecast, as determined in Section VI, and the capacity of Northern's existing long-term resources, as shown in Section VII, Current Portfolio. The difference is known as the Resource Balance. Separate comparisons are provided, based on Normal Year requirements, Design Year requirements and Design Day requirements.

The Resource Balance in this IRP compares the expected resource utilization under Normal and Design Year conditions to the respective Planning Loads. Table VIII-1 lists the Normal and Design Year utilization of the long-term resources in Northern's portfolio by season. Resources are organized by path, consistent with the resource descriptions provided in Section VII, Current Portfolio.

Table VIII-1: Northern Utilization of Long-Term Resources by Capacity Path (Dth)

Normal Year Resource Utilization	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Tennessee FS-MA Storage Path	967,600	964,956	964,956	964,956	967,600
Tennessee Niagara Pipeline Path	838,560	839,625	840,565	841,352	844,422
Algonquin Receipts Pipeline Path	190,152	188,901	188,901	188,901	190,152
Atlantic Bridge Ramapo Pipeline Path	2,745,000	2,737,500	2,737,500	2,737,500	2,745,000
Tennessee Long-Haul Pipeline Path	1,838,138	1,912,306	1,979,453	1,979,453	1,992,562
Union Dawn Storage Path	8,362,483	8,457,328	8,556,910	8,710,491	8,872,713
Iroquois Receipts Pipeline Path	977,975	971,541	971,541	971,541	977,975
Lewiston LNG	75,240	74,760	75,000	75,000	75,240
Utilization of Long-Term Capacity	**15,995,148**	**16,146,917**	**16,314,826**	**16,469,193**	**16,665,664**

Design Year Resource Utilization	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Tennessee FS-MA Storage Path	967,600	964,956	964,956	964,956	967,600
Tennessee Niagara Pipeline Path	838,524	839,589	840,549	841,336	844,407
Algonquin Receipts Pipeline Path	190,152	188,901	188,901	188,901	190,152
Atlantic Bridge Ramapo Pipeline Path	2,745,000	2,737,500	2,737,500	2,737,500	2,745,000
Tennessee Long-Haul Pipeline Path	1,992,562	1,979,453	1,979,453	1,978,154	1,992,562
Union Dawn Storage Path	8,825,681	8,974,397	9,128,228	9,271,564	9,436,887
Iroquois Receipts Pipeline Path	977,975	971,541	971,541	971,541	977,975
Lewiston LNG	75,240	74,760	75,000	75,000	75,240
Utilization of Long-Term Capacity	**16,612,733**	**16,731,097**	**16,886,128**	**17,028,952**	**17,229,821**

The Resource Balance analysis provides guidance as to the adequacy of the current portfolio and the level of additional long-term resources that are required to reliably and cost-effectively meet Northern's planning load during the five-year planning period (i.e., the 2023/24 gas year through the 2027/28 gas year) covered in this IRP.

The remainder of this section includes table and charts depicting the following:

Part B, Normal Year Resource Balance;

Part C, Design Year Resource Balance;

Part D, Design Day Resource Balance.

B. Normal Year Planning Load Resource Balance

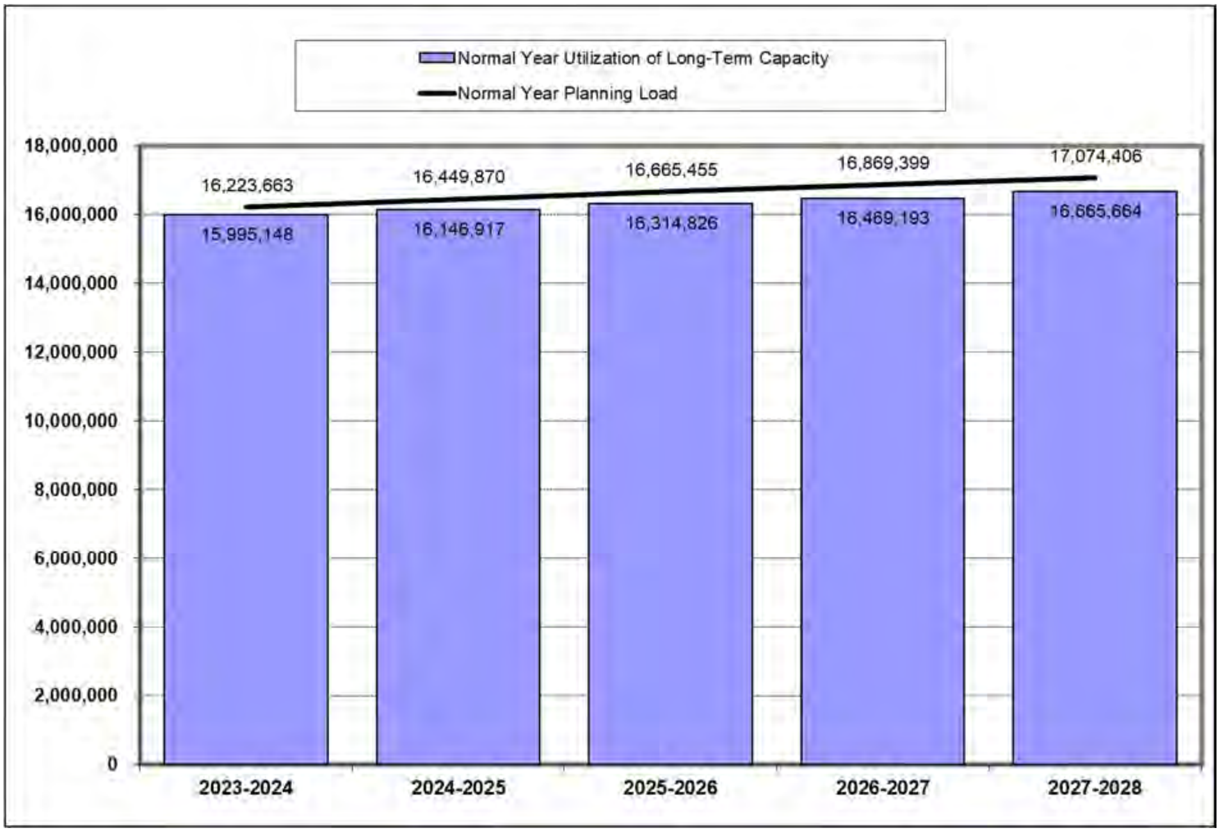
In calculating Resource Balance, Northern assumes renewal or replacement of all existing long-term resources. All of Northern's current, pending and proposed long-term capacity resources provide reliable, cost-effective service.

Table VIII-2 provides the Normal Year Resource Balance over the planning horizon and Figure VIII-1 depicts the data graphically. The comparisons show that Northern's Normal Year Planning Load Forecast is greater than the expected utilization of its Long-Term Capacity. In other words, Northern requires incremental supply to meet its Planning Load forecast under Normal Year weather conditions. Notably, the addition of the Atlantic Bridge, Portland XPress and Westbrook Xpress capacity has reduced the Resource Balance, and thus Northern's need for incremental resources, relative to Northern's prior IRP.

Table VIII-2: Normal Year Resource Balance (Dth)

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Normal Year Utilization of Long-Term Capacity	15,995,148	16,146,917	16,314,826	16,469,193	16,665,664
Normal Year Planning Load	16,223,663	16,449,870	16,665,455	16,869,399	17,074,406
Normal Year Resource Balance	**(228,515)**	**(302,953)**	**(350,629)**	**(400,206)**	**(408,742)**

Figure VIII-1: Chart of Normal Year Resource Balance (Dth)



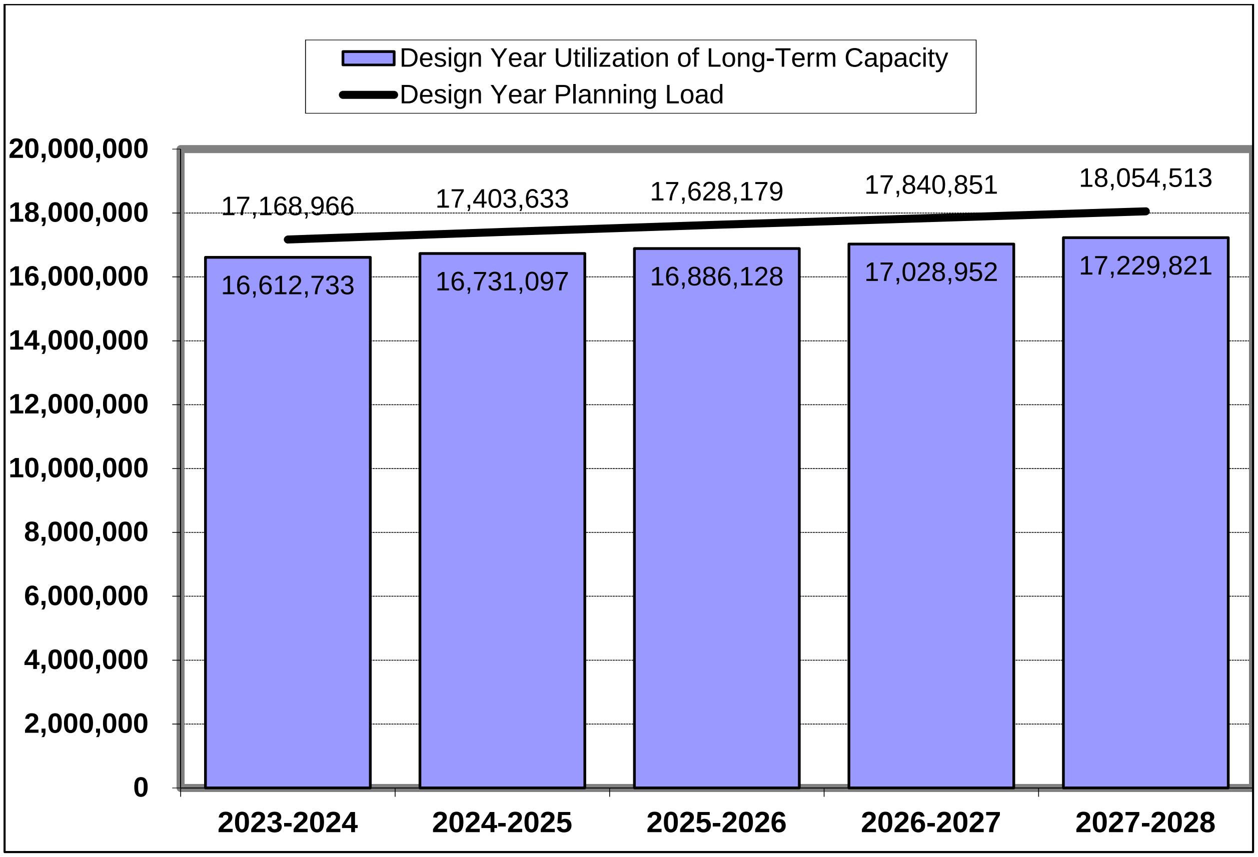
C. Design Year Planning Load Resource Balance

Table VIII-3 provides the Design Year Resource Balance over the planning horizon and Figure VIII-2 depicts the data graphically. As with the Normal Year Resource Balance, the Company's Long-Term Capacity is not sufficient to meet the Design Year Planning Load throughout the Planning Period. Notwithstanding the recent capacity additions, Northern still requires incremental resources to meet its Design Year Planning Load.

Table VIII-3: Design Year Resource Balance (Dth)

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Design Year Utilization of Long-Term Capacity	16,612,733	16,731,097	16,886,128	17,028,952	17,229,821
Design Year Planning Load	17,168,966	17,403,633	17,628,179	17,840,851	18,054,513
Design Year Resource Balance	**(556,233)**	**(672,537)**	**(742,051)**	**(811,899)**	**(824,692)**

Figure VIII-2: Chart of Design Year Resource Balance (Dth)



D. Design Day Planning Load Resource Balance

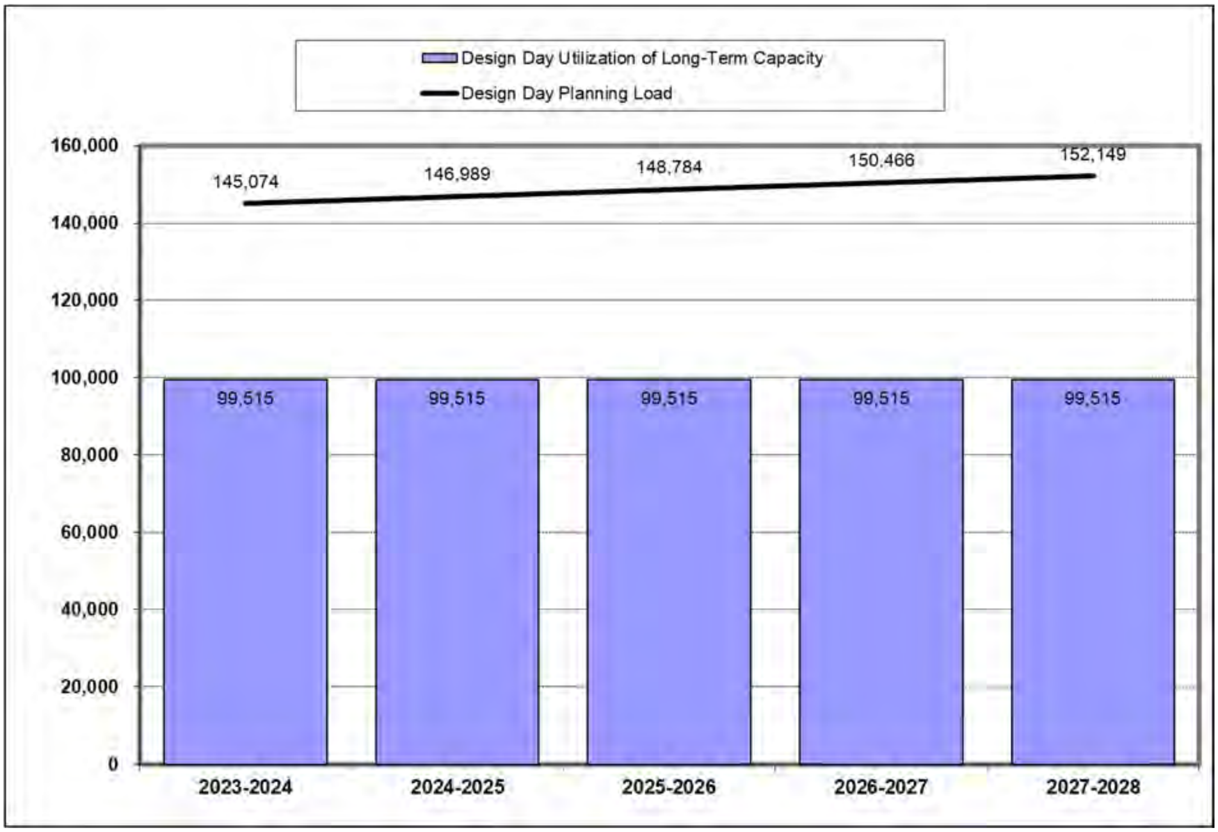
In order to align the timing of resource need with resource availability, the resource balance is was also prepared under Design Day conditions. Table VIII-4 provides the Design Day Resource Balance over the planning horizon and Figure VIII-3 depicts the data graphically.

Table VIII-4: Design Day Resource Balance (Dth)

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Design Day Utilization of Long-Term Capacity	99,515	99,515	99,515	99,515	99,515
Design Day Planning Load	145,074	146,989	148,784	150,466	152,149
Design Year Resource Balance	**(45,559)**	**(47,474)**	**(49,269)**	**(50,951)**	**(52,634)**

The Design Day comparison of planning load and available resources tells a similar story as did the annual comparisons, indicating that Northern's long-term resources are not adequate to meet Planning Load under design day conditions. Northern's long-term resources are projected to be short of Design Day Planning Load by 45,559 Dth in 2023/24. In Section XI, Preferred Portfolio, planning load requirements are looked at more closely using load duration curves and other tools.

Figure VIII-3: Chart of Design Day Resource Balance (Dth)



As seen in both tabular and graphic form above, under Normal Year, Design Year and Design Day conditions, Northern's Long-Term Capacity Portfolio is insufficient to meet the forecast Planning Load. Northern addresses this deficiency on behalf of its Sales Service customers through the purchase of delivered supplies. Pursuant to both Maine and New Hampshire Delivery Service Terms and Conditions, delivered supplies are not assignable to retail marketers and so the Company considers only Sales Service customer requirements when entering into these types of purchases.

IX. Incremental Resources

Key Takeaways

Key takeaways in this chapter include the following:

- *In order to better understand potential future contributions to supply planning, Northern has begun to model incremental Energy Efficiency. Initial parameters, assumed costs and projected annual and cold days savings (demand reductions) are provided.*
- *Traditional gas supply resources will be needed given the magnitude of the identified Resource Balance. The availability of incremental supply however is extremely limited. During recent years, Northern has tried to identify an LNG project and has sought offers for delivered peaking supply. Northern continues to explore resource additions.*
- *The Company has also explored alternative supply resources, namely RNG, during recent years. The Company has a better developed understanding of these resources and the markets around them, and has developed a gas quality standard for potential projects that might interconnect into the distribution system.*

A. Introduction

In this Section IX, Northern identifies potential demand and supply resource options that could meet the portfolio needs identified in the Resource Balance Section. Those needs, which reflect a lack of peaking resources, are refined further in Section X, Preferred Portfolio, with the use of Load Duration Curves.

Northern intends to renew all existing Capacity Resources. Renewal dates are provided in Table VII-3. Northern anticipates renewing all contracts primarily because: (i) as illustrated in this IRP, Northern requires the capacity to meet Planning Load; (ii) legacy capacity is heavily depreciated and therefore much less expensive than new capacity; and (iii) certain of the pipeline capacity is physically connected to Northern (or Granite) or is used to effectuate the exchange arrangement. Moreover, once turned back, legacy capacity typically cannot be reacquired.

Northern monitors new supply alternatives and opportunities by staying informed of developments within the regional natural gas market. In order to stay informed on both market and regulatory developments, Northern is a member of the Northeast Gas Association ("NGA") and the American Gas Association ("AGA") and also participates with other LDCs in New England in various matters of common interest. Northern also subscribes to natural gas market periodicals, such as Platt's *Gas Daily*, and monitors pipeline Electronic Bulletin Board ("EBB") postings for additional information that may affect the natural gas market. Most importantly, Northern maintains business relationships with pipelines, suppliers and other parties pursuing or offering solutions to supply challenges. These activities help Northern to identify developers and projects that could meet the needs Northern may require.

Although each state in which Northern operates maintains established processes for defining and funding cost-effective Energy Efficiency, this section identifies additional Energy Efficiency as an incremental resource that Northern can evaluate to identify the impact on supply costs and resource impacts of increasing Energy Efficiency savings targets and funding. Northern has not yet completed its analysis of incremental Energy Efficiency, nor has it determined how it would pursue incremental efficiency savings if evaluated to be cost-effective other than by advising the parties directly involved in the development and administration of the established programs in each State.

The rest of Section IX includes the following:

Part B, Incremental Energy Efficiency, describes how the Company is evaluating additional Energy Efficiency as a means to reduce its incremental resource needs, supply costs and other resource impacts;

Part C, Traditional Supply Resources, discusses potentially available traditional gas supplies such as pipeline, storage and peaking capacity or firm delivered peaking service;

Part D, Alternative Supply Resources, discusses non-pipeline supply options including Renewable Natural Gas (RNG) that may be available to reduce incremental resource needs.

B. Incremental Energy Efficiency

The IRP reflects the latest information on energy efficiency programs and savings targets from the established Energy Efficiency programs in each state as reductions to the demand forecast and thus Planning Load. See Section III.B.1 for a general description of the efficiency program administration in each state, Section V.C.3.b and Section V.C.3.f for a description of how the demand reductions applied to the demand forecast, Section V.E for the impact of efficiency programs on the demand forecast and Section VII.B for a description of the current programs. As shown in Table V-36, energy efficiency savings are expected to reduce forecasted throughput under normal weather conditions by more than 1.0 Bcf over the five-year planning period.

In order to better understand the potential impact of Energy Efficiency on the Company's gas supply planning, the Company has undertaken to model Incremental Energy Efficiency, which would be over and above the efficiency spending and savings from current customer funded programs. This evaluation is ongoing, but the Company provides its approach and initial parameters that are under review.

The Company began with a review of programs Northern offers in the New Hampshire Division. Specifically, we reviewed Northern's 2023 Plan offerings, as provided on page 6 of Appendix 4. The Company selected one Residential program and one Commercial and Industrial ("C&I") Program. After reviewing average measure life (Lifetime MMBtu Savings divided by Annual MMBtu Savings) and average unit Lifetime unit cost (Utility Cost / Lifetime MMBtu Savings), and considering overall appropriateness, the Company selected Energy Star Homes as the Residential program and Small Business Energy Solutions as the C&I program. Specific considerations for the Residential program selection were the high Benefit/Cost Ratios and long measure life. Specific considerations for the C&I program selection included the fact that small C&I customers are more likely to choose Sales Service rather than to select Supplier Service, thus the efficiency savings would be more likely to impact Northern's supply requirements than the Large customer offering. Table IX-1 shows the selected programs, average measure life and Lifetime unit cost.

Table IX-1: Review of New Hampshire Program Offerings

Program Cost-Effectiveness - 2023 PLAN											Northern Utilities Inc. NHPUC Docket No. DE 20-092 March 1, 2022 Plan Filing (2022-2023) 2023 Plan - REVISED Attachment J1		
	Benefit/Cost Ratios											
	Total Resource Cost Test (Net)	Granite State Test (Net)	Total Resource Cost Test (Net)	Granite State Test (Net)	Utility Costs ($000 - 2022$)[2]	Customer Costs ($000 - 2022$)[2]	Number of Customers Served	Annual Net MMBtu Savings	Lifetime Net MMBtu Savings	Measure Life (Yrs)	Cost / Life MMBtu
Residential Programs											
B1 - Home Energy Assistance	1.01	1.01	484.1	484.1	479.3	0.0	56	2,208.4	47,567.5	21.5	$10.08
A1 - Energy Star Homes	1.57	1.93	698.3	620.9	321.2	124.8	106	2,637.0	63,425.0	**24.1**	**$5.06**
A2 - Home Performance with Energy	1.02	1.11	434.8	386.0	347.3	79.6	6	1,798.6	38,254.5	21.3	$9.08
A3 - Energy Star Products	1.18	1.83	347.5	308.0	168.2	127.5	182	1,835.6	32,492.1	17.7	$5.18
A4 - Residential Behavior	1.48	1.30	63.8	56.2	43.3	0.0	11,200	5,847.4	5,847.4	1.0	$7.41
A6c - Res Education	-	-	-	-	20.0	0.0	-	-	-		
Sub-Total Residential	**1.19**	**1.35**	**2,028.6**	**1,855.1**	**1,379.2**	**331.9**	**11,550**	**14,327.0**	**187,586.5**		
Commercial, Industrial & Municipal											
C1 - Large Business Energy Solutions	2.12	3.83	2,163.0	1,922.1	502.0	520.3	108	14,307.9	220,365.6	15.4	$2.28
C2 - Small Business Energy Solutions	2.54	3.10	1,718.2	1,540.6	497.4	179.1	140	10,830.0	156,347.9	**14.4**	**$3.18**
C6c - C&I Education	-	-	-	-	17.9	-	-	-	-		
Sub-Total Commercial & Industrial	**2.26**	**3.40**	**3,881.3**	**3,462.6**	**1,017.4**	**699.4**	**248**	**25,137.8**	**376,713.5**		
Total	**1.72**	**2.22**	**5,909.9**	**5,317.7**	**2,396.6**	**1,031.4**	**11,798**	**39,464.8**	**564,300.0**		

Notes:
(1) The Granite State Test is used as the primary cost test, as approved in Order No. 26,322, and includes an annual NEI adder of $405.71 per weatherization project in the Home Energy Assistance program. For the Secondary Granite State Test, NEI adders of 25% for Residential and 10% for C&I
(2) Utility and Customer Costs and Benefits are expressed in 2022 Dollars.
(3) Per past precedent, discount and inflation rates have been updated for the year in which measures will be installed, and were updated as of June 2021 for program year 2022.

To model incremental savings from the selected programs, the Company established annual benchmark volumes (MMBtu) for each program. Specifically, the Company modeled 1,000 MMBtu per year from the Residential program and 4,000 MMBtu per year from the C&I program, which represents 38 percent and 37 percent, respectively, of the annual savings from the approved budget for the two programs. This level of savings relates to approximately 40 Residential and 52 C&I installations. The Company then modeled five years of efficiency installations of the benchmark volumes by layering in the expected savings as installations would be completed over time and overlaying those with the seasonal demand pattern of Northern's Residential and C&I customers to calculate expected saving.[101] Although installations were modeled for five years, the savings would continue through the respective measure lives.

[101] Using the approach described in Section V.C.3.b.

The Utility Costs shown in Table IX-1 reflect only direct program costs. The Company therefore calculated administrative costs by incorporating an adder to account for Evaluation, measurement, and verification ("EM&V") costs, internal administration and external administration costs, derived as shown in Table IX-2.

Table IX-2: Administrative Cost Assumptions

Administrative Cost Assumption					
Source: NHPUC Docket No. IR 22-042, 2021 Program Year Compliance Filing, Order No. 26,261 Report 9.v. Market Barriers					
C&I			**RES**		
Total Cost	$805,938		Total Cost	$1,218,840	
Total NPV Costs C&I Sector 2021	$935,064		Total NPV Costs C&I Sector 2021	$1,331,544	
Remaining	$129,126	$129,126	Remaining	$112,704	$112,704
EM&V	$38,251		EM&V	$39,952	
Internal Admin	$90,142		Internal Admin	$71,921	
External Admin	$734		External Admin	$830	
Total	$129,127	$129,127	Total	$112,703	$112,703
Admin as Share Total Cost	**13.8%**		**Admin as Share Total Cost**	**8.5%**	

Table IX-3 presents the benchmark savings levels and associated modeled costs the Company is reviewing, and shows how data from Table IX-1 was applied. Since the costs provided in Table IX-1 were in nominal 2022 dollars and since Energy Efficiency installations require significant labor and materials, the cost of which are subject to market conditions, the Company applied an inflation adjustment using a recent CPI forecast provided by EIA. In total, implementing the benchmark incremental Energy Efficiency for a five year period would cost approximately $1.8 million.

Table IX-3: Modeled Costs of Incremental Energy Efficiency

	Residential	C&I
Program Utility Costs ($000 - 2022$)	321.2	497.4
Annual Net MMBtu Program Savings	2,637	10,830
Annual Benchmark Savings (MMBtu)	1,000	4,000
Benchmark Savings / Program Savings	38%	37%
Annual Cost of Benchmark Savings ($)	$ 121,805	$ 183,712
Admin Cost Assumption	8.5%	13.8%
Total Annual Cost Benchmark Savings (2022$)	$ 132,115	$ 209,081

	Residential Benchmark Savings (Dth)	C&I Benchmark Savings (Dth)	CPI-U[1] (1982-84=1.00)	*Inflation Rate*	Annual Cost Residential	Annual Cost C&I
2022			2.928		**$ 132,115**	**$ 209,081**
2023	1,000	4,000	3.055	*4.34%*	$ 137,853	$ 218,162
2024	1,000	4,000	3.137	*2.68%*	$ 141,553	$ 224,018
2025	1,000	4,000	3.201	*2.04%*	$ 144,434	$ 228,578
2026	1,000	4,000	3.266	*2.02%*	$ 147,345	$ 233,184
2027	1,000	4,000	3.332	*2.03%*	$ 150,342	$ 237,927
Period					$ 721,527	$ 1,141,871

[1] *Annual Energy Outlook, EIA, March 2023*

Table IX-4 provides an annual summary of demand reductions from five years of Incremental Energy Efficiency installations at the benchmark level to be modeled. These savings would continue in the future for the average measure lives of measures installed. Table IV-5 provides daily impacts on Planning Load for the final 10 days of January, which reflects the Company's cold snap period. On the coldest days of the year, by the end of the five-year period, the Company projects Planning Load reductions of over 100 Dth per day.

Table IX-4: Benchmark Incremental Energy Efficiency Savings – Design (Dth)

Gas Year	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings
2022/23	-231	-1,229	-14	-1,474
2023/24	-1,309	-5,369	-63	-6,741
2024/25	-2,394	-9,536	-113	-12,043
2025/26	-3,479	-13,704	-163	-17,346
2026/27	-4,564	-17,873	-212	-22,649
CAGR	110.8%	95.3%	98.0%	98.0%
PERIOD				-60,254

Table IX-5: Normal and Design Impact on Daily Planning Load (Dth)

	Daily Incremental Energy Efficiency (Dth) - Normal					Daily Incremental Energy Efficiency (Dth) - Design				
January	Year 1	Year 2	Year 3	Year 4	Year 5	Year 1	Year 2	Year 3	Year 4	Year 5
22	-2	-26	-50	-74	-97	-2	-28	-54	-80	-106
23	-2	-23	-43	-64	-85	-2	-25	-47	-70	-93
24	-2	-23	-45	-66	-87	-2	-25	-49	-72	-95
25	-2	-24	-46	-67	-89	-2	-26	-50	-74	-97
26	-2	-31	-59	-87	-116	-3	-33	-64	-95	-126
27	-2	-28	-53	-78	-104	-2	-30	-58	-85	-113
28	-2	-24	-46	-68	-90	-2	-26	-50	-74	-98
29	-2	-28	-54	-80	-106	-2	-31	-59	-87	-115
30	-2	-28	-54	-80	-106	-2	-31	-59	-87	-116
31	-2	-28	-55	-81	-107	-2	-31	-59	-88	-117

The Company undertakes this effort in good faith and looks forward to sharing future results. The modeled benchmark savings levels could be increased if the Company's modeling identifies benefits. If modeling shows positive benefits, the Company would review the Achievable Potential defined in the Dunksy Report.[102]

C. Traditional Supply Resources

The Company undertook significant efforts to identify incremental resources during the time since the Company's 2019 IRP. Consistent with the themes described in the Regional Market Outlook, the region remains constrained from a natural gas capacity standpoint, with very limited opportunities to add capacity. In March 2020, the Company issued an RFP seeking proposals to develop a Liquefied Natural Gas (LNG) facility. The Company sought proposals that could meet its incremental resource need of approximately 50,000 Dth/day and 500,000 Dth annually identified in the 2019 IRP. After evaluating responses, the Company negotiated for an extended period with a development team but to date no definitive project has resulted. As discussed in the current IRP, the Company continues to have a significant unmet need for peaking capacity.

The Company continues to rely on Delivered Supply to meet its peaking supply requirements. As explained in Cost of Gas proceedings, the Company had a multi-year contract for delivered peaking supply, however that contract is ending and despite the Company's efforts to solicit peaking supply offers, currently the Company has no peaking supply under contract for the coming winter of 2023/24. Note that under the Delivery Service Tariffs, after Capacity resources in Northern's portfolio are allocated among Sales Service and capacity assigned Delivery Service customers, incremental supply requirements are to be purchased by each retail marketer or by Northern to serve their respective customers. Thus, any purchase of Delivered Supply by Northern would be for Sales Service customers.

[102] New Hampshire Potential Study Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021 – 2023, Dunsky Energy Consulting, October 2020.

Northern's Resource Balance in 2027/28 is projected to be approximately 52,000 Dth on Design Day and 824,000 Dth on Design Year. Currently, Northern's only option to meet these incremental requirements is to purchase comparable volumes as Delivered Supply. However, there are very few parties willing and able to provide a delivered peaking service sufficient to meet Northern's remaining requirements. The limited availability creates questions about the long-term certainty and availability of Delivered Supply and also impacts prices Northern can expect to pay for such service. If circumstances prevent a single or small group of suppliers from offering Delivered Supply at any point in the future, Northern would be unable to meet its supply obligations.

Northern is monitoring opportunities to contract for additional pipeline capacity. As noted in the Regional Market Outlook, both PNGTS and Algonquin anticipate issuing open seasons in the near future.

The Company is monitoring and evaluating these opportunities, but recognizes that development of traditional supply resources, such as pipeline expansions and LNG projects, can take many years to get approved and then constructed and are likely to face opposition given the broad policy environment that favors renewable energy sources.

D. Alternative Supply Resources

Renewable Natural Gas (RNG) is the primary alternative resource the Company has pursued and anticipates continuing to pursue. RNG is a renewable alternative to geologic natural gas. The EPA describes RNG as biogas that has been upgraded for use in place of fossil natural gas, where the biogas used to produce RNG comes from a variety of sources, including municipal solid waste landfills and anaerobic digesters at wastewater treatment plants, livestock farms, food production facilities and organic waste management operations.[103] RNG can also be produced via thermal gasification of forest residue and other organic material or power to gas technologies, however the vast majority of RNG produced today is from landfills and agriculture based digesters. Once processed, RNG is interchangeable with traditional fossil gas and can be injected directly into the distribution system to serve customers.

The Company undertook significant efforts to identify RNG resources during the time since the Company's 2019 IRP. In September 2020 Northern issued a Request for Expressions of Interest ("RFEI") as an initial step in discovering the potential availability, pricing and other features of RNG. The Company received a robust response, although indicative pricing was much higher than the price of fossil gas. The Company also spent significant time evaluating project that would deliver RNG from agricultural and food waste into its system, however this project never materialized. At a high level, to date the Company's experience in seeking RNG supply is that production costs are generally high such that projects need to achieve reasonable scale or be co-located close to the end use to minimize transportation costs in order to be viable. Beyond production costs, various compliance markets strongly incent RNG production with

[103] US EPA website: https://www.epa.gov/lmop/renewable-natural-gas.

attractive incentives, creating relatively high opportunity costs for voluntary RNG buyers. These markets include the EPA's Renewable Fuel Standard ("RFS") and the California Low Carbon Fuel Standard ("LCFS"), each of which targets the transportation sector. Proposed changes to the RFS may reduce the attractiveness of creating RNG, as the EPA anticipates awarding credits for electric renewables tied to transportation. Assuming implementation of these changes, developers of biogas would need to decide whether to create RNG or simply generate power (which can be done without upgrading the biogas to pipeline quality, as required to make RNG).

Following significant study, in February 2022 the Company adopted a system wide gas quality standard ("Natural Gas Quality and Delivery Point Standards for Non-Traditional Sources of Gas") for RNG that would be injected directly into the distribution system. In 2022, the Company sponsored legislation in New Hampshire, SB 424, relative to renewable energy and natural gas, which was passed into law ("NH RNG Law"). Under the NH RNG Law, LDCs may purchase up to five percent of sales as RNG with the approval of the NHPUC, and all RNG purchases must be made pursuant to an RFP developed in coordination with the New Hampshire Department of Energy and the LDC may not invest in an RNG project other than for equipment relating to interconnection, such as measurement.

The Company remains optimistic that RNG will be a viable supply opportunity, which may become increasingly attractive for supply purposes as constructing additional traditional infrastructure becomes increasing difficult. The renewable aspects of RNG are attractive, as it allows energy needs to be met with gaseous materials already present in the biosphere rather than by extracting more geologic gas. The Company continues to explore supply options and is also exploring voluntary options it can make available to customers.

X. Emissions and Public Health

Key Takeaways

Key takeaways in this chapter include the following:

- *As customers consume natural gas, both greenhouse gases (GHG) and air quality (AQ) pollutants are emitted. This section quantifies both GHG and AQ emissions associated with customer consumption over the forecast period, and also reports on public health impacts.*
- *All gas currently delivered to customers is sourced from geologic production and has the same essential chemical characteristics. To the extent the Company identifies resources from renewable source technologies or with different chemical characteristics, the Company would evaluate the incremental differences and impacts.*

A. Introduction

The Company purchases and delivers natural gas to customers. Natural gas is primarily methane (CH4), which as explained in the Clean Air Act part of the Planning Environment Section, is a Greenhouse Gas ("GHG"). The Company has made extensive efforts to improve its handling of the gas we deliver to customers in parallel to companies that operate in other segments of the natural gas supply chain.

In this section, the Company presents summary emissions and public health impacts of the combustion of natural gas by customers quantitatively with current environmental metrics via the EPA. Please note that customers must consume some fuel or energy source to maintain their livelihoods, and customers have choices for heating and other end uses. Customer conversion from heating oil to natural gas reduces greenhouse gas emissions by approximately 28 percent and greatly reduces air quality pollutants, as explained in the Clean Air Act part of Section III.

B. Systemwide Emissions and Public Health Impact

Combustion from the Company's customers differs depending on the customer segment. Of the three customers segments: Residential, Commercial and Industrial Low Load Factor (C&I LLF), and Commercial and Industrial High Load Factor (C&I HLF), the production of GHGs is dependent on the process and equipment being used for combustion. Unfortunately, a granular analysis is difficult to perform without a priori knowledge of the equipment that each individual customer may use, which reduces the ability to provide more accurate values of emissions. Furthermore, there is no applicable metric to measure those customers within the Company's systems that utilize any form of GHG recapturing. As an example, a residential customer who uses natural gas for a single cooking appliance does not consume gas at the rate of one who has several gas appliances and home heating. For the work provided in this section the following assumptions are made:

- All natural gas in the system is of geologic gas quality (including liquefied gas supplied to the system from the Lewiston LNG plant), i.e. between 997 and 1,100 BTUs per cubic foot at standard temperature and pressure
- Gas quality is approximately 95% methane, 3% natural gas liquids (i.e. ethane and propane), and 2% non-hydrocarbon gases (i.e. CO_2 or Nitrogen)[104]
- Natural Gas combustion rate of 0.0053 Metric Tons of CO_2 per therm[105]
- Residential and Commercial nitrogen oxide (NOx) production is represented as 0.092 and 0.098 lbs per therm[106]. Note this assumes the high and low values associated with furnaces, cooking appliance have been shown to produce negligible NOx.
- The Public Health Cost of NOx is approximately $14,700 per short ton (2,000 lbs).[107] Note this was derived via the EPA using their COBRA model.

The tables below will provide the historical and forecasted values for CO_2, NOx, and Public Health Costs for Northern as a whole, and with the assumptions provided above. Note: because this analysis is applying singular combustion factors, the compound annual growth rates (CAGRs) are the same for each table. The Company looks to improve upon these methods in the following IRP filing if more granular data becomes available from the customer base and to the extent resources such as incremental Energy Efficiency, Renewable Natural Gas or other emissions reducing supplies or attributes are evaluated.

[104] https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-annex-2-emissions-fossil-fuel-combustion.pdf (Table A-35).
[105] The Climate Registry, 2021 Climate Registry Default Emissions Factors, released May 2021. https://www.theclimateregistry.org/wp-content/uploads/2021/05/2021-Default-Emission-Factor-Document.pdf. See Table 1.1, page 5 of 81, 2021-Default-Emission-Factor-Document.pdf (theclimateregistry.org) (Note: CH4 or N2O are not included here because these emissions from combustion are considered to be de minimis).
[106] https://www.epa.gov/sites/default/files/2020-09/documents/1.4_natural_gas_combustion.pdf
[107] U.S. Environmental Protection Agency. “Public Health benefits per kWh of Energy Efficiency and Renewable Energy in the United States: a Technical Report.” Epa.gov. Available at https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf

Table X-1: Northern Utilities, Inc. - GHG Emissions Metric Tons of CO_2

Gas Year	Emissions Per Customer	Total Emissions	Energy Efficiency Reduction	Net Emissions
2017/18	15.551	1,021,861	0	1,021,861
2018/19	15.929	1,058,664	0	1,058,664
2019/20	15.064	1,038,576	0	1,038,576
2020/21	15.520	1,057,777	0	1,057,777
2021/22	15.501	1,082,579	0	1,082,579
CAGR	-0.1%	1.5%	n/a	1.5%
Gas Year	Emissions Per Customer	Total Emissions	Energy Efficiency Reduction	Net Emissions
2022/23	15.937	1,117,011	-1,633	1,115,378
2023/24	16.079	1,134,802	-6,546	1,128,257
2024/25	16.164	1,154,374	-11,018	1,143,355
2025/26	16.187	1,172,793	-15,484	1,157,309
2026/27	16.188	1,190,331	-19,950	1,170,381
CAGR	0.4%	1.6%	87.0%	1.2%

The table above provides the total historical and forecasted CO_2 emissions for Northern. Although the total emissions are expected to go up including the emissions per customer, it should be noted that through energy efficiency programs the total annual growth is expected to decrease from 1.5% to 1.2%.

Table X-2: Northern Utilities, Inc. - GHG Emissions lbs. NOx

Gas Year	Emissions Per Customer	Total Emissions	Energy Efficiency Reduction	Net Emissions
2017/18	27.336	1,831,006	0	1,831,006
2018/19	27.997	1,895,865	0	1,895,865
2019/20	26.499	1,861,761	0	1,861,761
2020/21	27.293	1,896,271	0	1,896,271
2021/22	27.273	1,941,997	0	1,941,997
CAGR	-0.1%	1.5%	n/a	1.5%
Gas Year	Emissions Per Customer	Total Emissions	Energy Efficiency Reduction	Net Emissions
2022/23	28.035	2,003,334	-2,834	2,000,500
2023/24	28.285	2,035,380	-11,362	2,024,018
2024/25	28.438	2,070,939	-19,126	2,051,813
2025/26	28.484	2,104,559	-26,878	2,077,680
2026/27	28.491	2,136,623	-34,630	2,101,992
CAGR	0.4%	1.6%	87.0%	1.2%

Table X-3: Northern Utilities, Inc. - Public Health Cost $

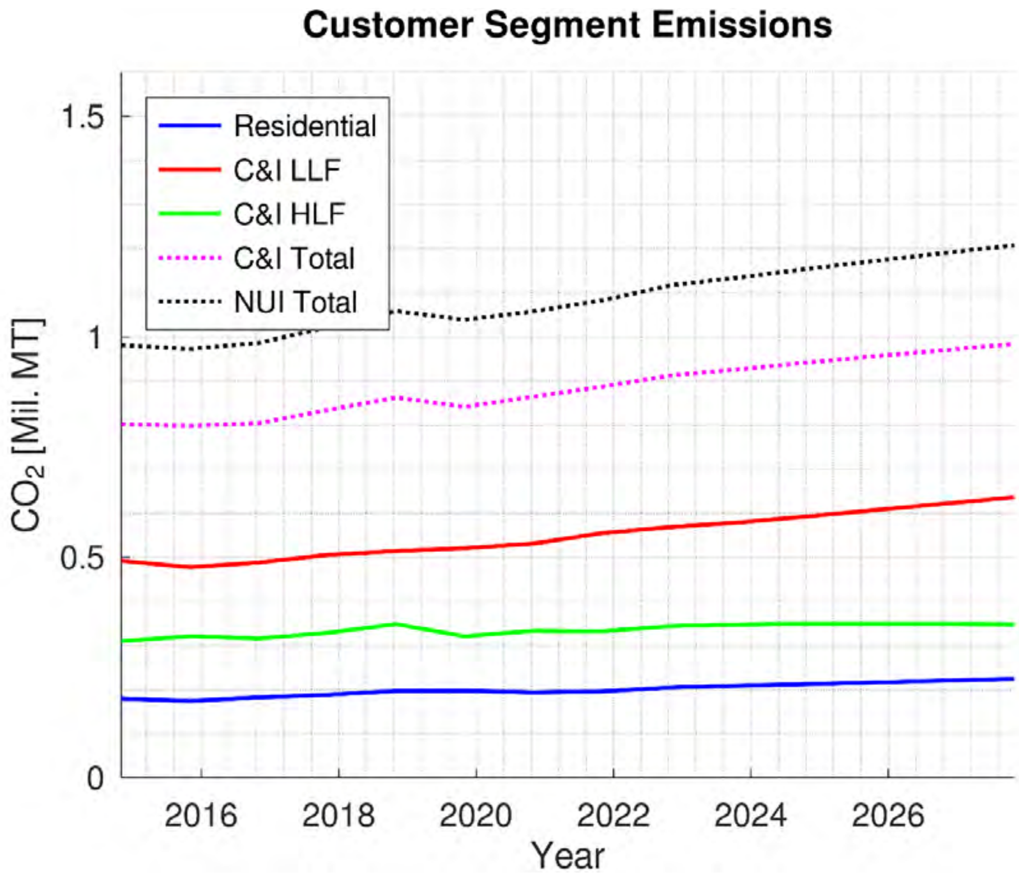
Gas Year	Public Health Cost Per Customer	Public Health Cost Total	Energy Efficiency Reduction	NUI Net Public Health Cost
2017/18	$201.80	$13,492,064	$0	$13,492,064
2018/19	$206.68	$13,970,753	$0	$13,970,753
2019/20	$195.60	$13,718,123	$0	$13,718,123
2020/21	$201.48	$13,972,344	$0	$13,972,344
2021/22	$201.32	$14,308,378	$0	$14,308,378
CAGR	-0.1%	1.5%	n/a	1.5%
Gas Year	Public Health Cost Per Customer	Public Health Cost Total	Energy Efficiency Reduction	NUI Net Public Health Cost
2022/23	$206.95	$14,760,604	-$20,947	$14,739,656
2023/24	$208.79	$14,996,623	-$83,981	$14,912,641
2024/25	$209.92	$15,258,303	-$141,369	$15,116,934
2025/26	$210.25	$15,505,602	-$198,666	$15,306,936
2026/27	$210.30	$15,741,423	-$255,963	$15,485,461
CAGR	0.4%	1.6%	87.0%	1.2%

Although the rate of emissions growth is decreasing, that does not mean to imply that total emissions and health costs are expected to decrease. Increased natural gas combustion from customers will result in increased emissions. However, it is important to note that older equipment that continues to operate could have as low as 56% combustion efficiency at the time of purchase, where new equipment can operate up to approximately 98% combustion efficiency.[108] Natural market adoption of higher efficiency equipment, combined with increasing efficiency standards and efforts made through the Energy Efficiency programs, the annual rate of emissions should begin to see significant decline within the coming decade.

The following figures illustrate the way that natural gas emissions are produced by rate class (note these values are prior to any energy efficiency reduction):

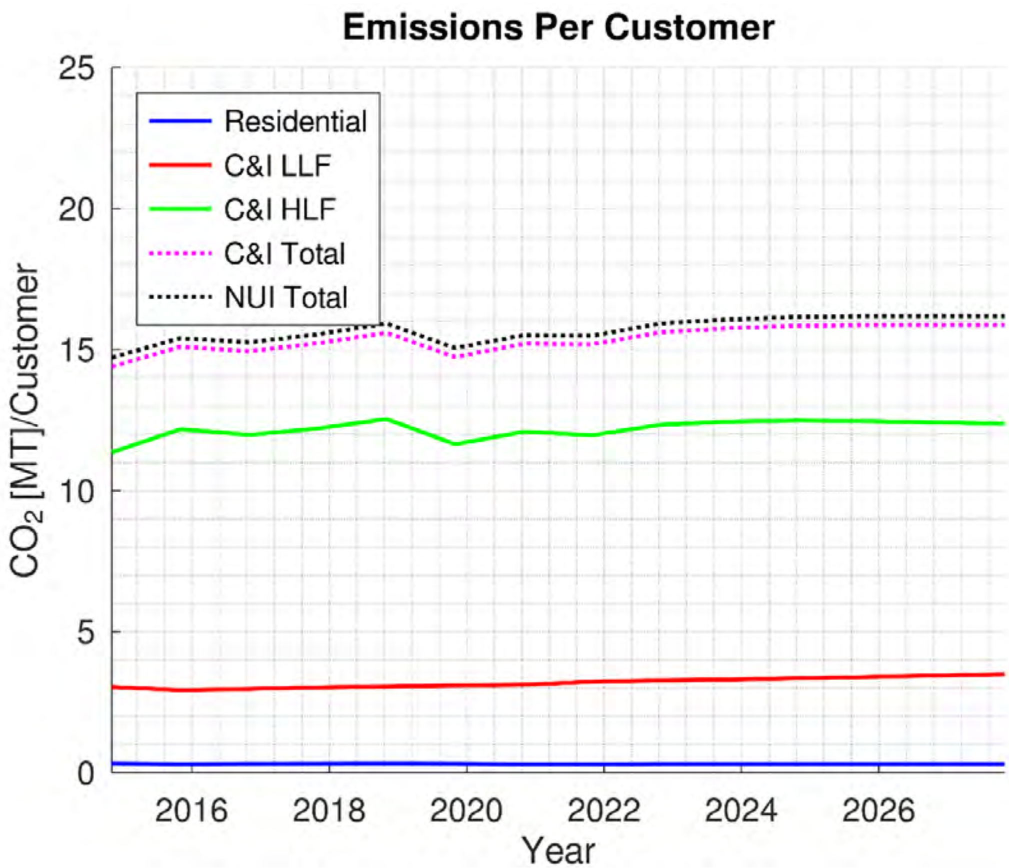
[108] U.S. Department of Energy: https://www.energy.gov/energysaver/furnaces-and-boilers#:~:text=Although%20older%20fossil%20fuel%20furnace,useful%20heat%20for%20your%20home.

Figure X-1: Greenhouse Gas Emissions by Customer Segment



Currently, Northern's largest customer segment in terms of emissions is the C&I Low Load Factor customer segment. This is expected, as that customer segment is currently the largest and represents the most demand from Northern. Emissions per customer are reviewed by customer segment in the following Figures.

Figure X-2: Greenhouse Gas Emissions Per Customer



It can be seen that although C&I LLF customer segment produces the most aggregate emissions, they operate at about 3 Metric Tons of CO_2 per customer, while each C&I HLF customer is at approximately 12 Metric Tons of CO_2 per customer, equaling approximately four times as much as the C&I LLF customers. Although the LLF customer produce the most emissions, they are also seasonally dependent wherein they produce the most GHG due to colder weather. Conversely, C&I HLF customers can be explained via daily process loads that have little seasonal dependency, but could also be customers more likely to have recapture efforts or secondary heat reclamation.

Lastly, the production of greenhouse gasses is a byproduct of natural gas combustion in any form and Northern will continue to explore renewable and lower emitting resources such as additional Energy Efficiency and Renewable Natural Gas to provide customers with lower emissions energy choices while continuing to provide safe and reliable energy to our customers.

XI. Preferred Portfolio

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern's approach to Long-Term planning and procurement includes providing resources that reliably meet design planning criteria while providing significant utilization upon being put into service, avoiding excesses of capacity, providing renewal rights, operational and contractual flexibility and enhancing low and stable pricing.*
- *Northern relies largely on qualitative assessment criteria in its resource decision making process, assuming that based on quantitative analysis a given resource is comparably priced relative to available alternatives and the resource is shown to help meet design condition customer requirements.*
- *Northern may require regulatory pre-approval of significant contractual commitments undertaken to meet customer requirements at a reasonable cost.*

A. Introduction

As the Resource Balance section shows, Northern's long-term capacity resources are not sufficient to meet its design day, design year and normal year Planning Load forecast throughout the 5-Year Planning Period. The Company currently utilizes Delivered Supplies to meet the gap between design day and design year demands and long-term capacity resources for its Sales Service customer loads, particularly for peaking supply.

The Company's Preferred Portfolio for the Planning Period presented in this Integrated Resource Plan is to maintain the Current Resource Portfolio outlined in Section VII, including all current demand- and supply-side resources. Northern will need to continue to procure delivered peaking supplies to supplement the current resource portfolio to assure that it can meet Design Day and Design Year Planning Criteria for Sales Service customer loads until sufficient long-term resources can be developed or acquired.

Based on its modeled cost analysis, the Company has prepared the following for each year of the Planning Period.

- Design Cold Snap Analysis chart
- Winter and Summer Load Duration Curve charts for both Design and Normal Year
- CONFIDENTIAL Annual City-Gate Cost, Delivered Volumes and Unit Cost schedule for both Design and Normal Year

These charts and schedules are provided in Appendix 5 to this Integrated Resource Plan. These materials show in graphic and tabular format, Northern's projected utilization and cost of its supply-side resources to meet the projected Planning Load requirements.

Northern plans to continue to pursue cost-effective means of reducing its reliance upon Delivered Supplies to meet its Design Day and Design Year Planning Criteria. As such this Section XI also provides an overview of the Company's approach to long-term portfolio planning and reviews the evaluation methods the Company uses to identify resource needs and compare competing long-term resources.

The remainder of the Preferred Portfolio section is organized as follows:

Part B, Approach to Long-Term Planning, reviews the Company's portfolio planning objectives and goals;

Part C, Resource Evaluation Methods, reviews the analytical tools and qualitative assessments the Company uses in assessing supply resource commitments;

Finally, Part D, Regulatory Considerations, highlights the Company's efforts to comply with expectations of the Commissions that oversee the Company's procurement of supply resources, and the need for pre-approval of significant commitments and for consistency between jurisdictions.

B. Approach to Long-Term Planning

Northern takes the following approach to Long-Term Planning.

- Northern values a long-term resource portfolio of appropriate demand- and supply-side resources that is well-balanced with its projected Planning Load under Design Day and Design Year conditions throughout the Planning Period. Currently, Northern seeks to add resources to its long-term resource portfolio, but looks to do so as efficiently as possible to avoid excessive surpluses of capacity.
- Northern values long-term resources that are well sized to satisfy identified resource needs and provide for considerable utilization as soon as the resource is brought into service. For this reason, the Company has presented evaluations of Year 1 impacts in support of proposed new capacity in its recent requests for pre-approval of pipeline commitments.
- Northern values long-term resources that Northern is able to control beyond the Planning Period. For example, the Company favors upstream pipeline capacity with renewal rights over Delivered Supplies with fixed termination dates and no renewal rights. Rights to renew capacity resources assure sustainable access to the resource.
- Northern values a portfolio with sufficient flexibility to reliably balance supply with daily, monthly and seasonal demand requirements. Northern's demand requirements can change dramatically from day to day during the Winter Period, especially. The Company puts a

premium on resource flexibility as demand and market conditions change from day to day as well as year to year.

- Northern values access to liquid supply points with many buyers and sellers. This provides Northern with many options when seeking to purchase gas for its customers, as well as price transparency through published index prices and future pricing. Northern's distribution system is located in a supply constrained market with few buyers and sellers due to limited availability of supply and Northern is concerned about the sustainability of long-term reliance upon continued purchases of delivered peaking supply. On the PNGTS and MN US portion of Northern's system, where the majority of the customer demand is located, there is very limited price transparency, with neither published index prices nor futures prices for supply on these pipes.
- Northern values the contribution that investments in energy efficiency provide in terms of meeting customer energy requirements cost-effectively, including benefits such as reducing environmental impacts and promoting local economic development. The development and approval of energy efficiency resources is actively monitored in the Maine Division and actively pursued and implemented in the New Hampshire Division.
- Northern values compliance with all statutory and regulatory requirements related to natural gas supply.

C. Resource Evaluation Methods

Northern's approach to resource evaluation is consistent with its corporate mission to safely and reliably deliver energy for life and provide our customers with affordable and sustainable energy solutions.

1. Demand-side Resource Evaluation

Northern's Preferred Portfolio includes all cost-effective demand-side resources. Implementation of cost-effective demand-side resources ensures that the Company's portfolio of supply resources meets customer requirements in the most efficient, cost-effective manner possible. Energy efficiency savings are reflected in the Preferred Portfolio as reductions to Planning Load throughout the Planning Period based on a continuation of the most recently approved EE plans. Ongoing Energy Efficiency savings targets may be subject to change based on the triennial reviews undertaken in each state.

As explained in Section IX, Incremental Resources, the Company has undertaken to model Incremental Energy Efficiency, over and above the efficiency spending and savings from current customer funded programs, in order to better understand the potential impact of Energy Efficiency on the Company's gas supply planning. The Company will need to vet and carefully understand the impact of all modeling assumptions, and if results are deemed favorable, additional evaluation steps would need to be considered, including for example qualitative assessments such as viability (Project Development Risk) and approaches to promote incremental acquisition (investment in Energy Efficiency) would need to be defined, such as providing evaluation results to the established Program Administrators.

The Company utilizes both quantitative and qualitative approaches to review the different aspects of potential new supply-side resources.

Although the Preferred Portfolio (i.e., the combination of existing and incremental resources that meets forecasted load requirements over the planning period in a reliable manner at a reasonable cost) may need to be changed or adjusted over time to meet changes in customer, operational, market or regulatory conditions, the Company utilizes the following analytical framework to inform portfolio decisions regarding the adequacy of the portfolio and the appropriateness of potentially available incremental resources in satisfying identified resource needs.

- <u>Resource Balance Assessment</u> – Broadly identify incremental resource needs by comparing existing long-term resources to long-term planning load requirements, under the various weather and growth scenarios.
- <u>Landed Cost Analysis</u> – A landed cost analysis is developed to compare various resource project options.
- <u>Decision-Making Process</u> – Decisions regarding proposed resource additions are based primarily on qualitative criteria so long as the modeled cost of competing projects is comparable. This approach favors fundamentals that cannot be modeled quantitatively, such as locational diversity, viability and contracting issues. This approach also acknowledges that price forecasts change and reduces the possibility that major resource decisions are based primarily on such forecasts. Resource options determined to not meet critical threshold requirements, such as being deliverable to the Company's system are discarded and not evaluated further.
- <u>Qualitative Assessment</u> – Review and comparison of competing projects on basis of non-price characteristics to assess value of competing projects; characteristics include feasibility, viability, potential environmental, economic, and health-related impacts, and contribution to portfolio flexibility and diversity, location of delivery, renewal rights, other contractual issues, etc. The Company performs a qualitative assessment on each viable incremental resource identified, even if the resource may have had higher landed cost analysis results. This is to assure that the Company has a complete understanding of the relative value of each available resource.
- <u>Modeled Cost Analysis</u> – If several projects are identified as viable and the attributes and terms are known, then they are modeled in PLEXOS®. The primary output for decision-making purposes is total delivered portfolio cost, utilization rate for proposed new resource and

impact on utilization rate of other resources. The timing of pipeline open season decisions (when there may be only notice of a few weeks for the Company to determine whether it will participate in a proposed project) has necessitated the use of simpler analytical models. Load duration curves are used to assess utilization of resources coincident with the frequency and timing of resource needs. Cold snap analyses are used to assess adequacy of the portfolio.

Each of these steps described above are described further or demonstrated below. The Resource Balance Assessment was demonstrated in Section VIII. Landed Cost Analysis, Decision-Making Process, Qualitative Assessment and Modeled Cost Analysis are described further below.

2. Landed Cost Analysis

From a quantitative perspective, a landed cost analysis evaluates the delivered cost of various natural gas supply paths to a specific point. The typical landed cost approach assumes that the pipeline demand charges are evaluated at a 100% load factor (i.e., the transportation path is used every day at full volume) and variable and/or fuel charges are based on full contracted volumes. This approach allows multiple paths to be evaluated and compared in a transparent manner. Table XI-1 illustrates a generic (i.e., hypothetical) landed cost approach.

Table XI-1: Illustrative Landed Cost Approach

1	2	3	4		3+4
Path	**Gas Supply Basin**	**Gas Supply Cost**	**Pipeline 1**	**Pipeline 2**	**Total**
A	WCSB	Henry Hub + x	$D	N/A	Henry Hub + x + $D = A Total
B	Gulf of Mexico	Henry Hub + y	$E	$F	Henry Hub + y + $E + $F = B Total
C	Marcellus Shale	Henry Hub – z	$G	N/A	Henry Hub – z + $G = C Total

As shown in Table XI-1, the landed cost approach consists of four components: 1) alternative paths to transport gas supply to a specific point are identified; 2) the gas supply basin associated with each transportation path is identified; 3) the gas supply cost is calculated for each path in terms of Henry Hub plus or minus a basis differential; and 4) the transportation cost (i.e., demand, variable and fuel) for all pipelines within the path is calculated. Finally, the total landed cost for each path is calculated (i.e., the gas supply cost plus the total transport costs).

For example, as demonstrated in Table XI-1, Path A consists of a WCSB gas supply, which is priced at Henry Hub plus a basis differential of "x" and is transported on Pipeline 1 for a total landed cost comprised of the gas supply cost (i.e., "Henry Hub + x") and the transportation cost for Pipeline 1 (i.e., "$D"). Similarly, Path B consists of a Gulf of Mexico gas supply transported on both Pipeline 1 and Pipeline 2 for a landed cost comprised of the gas supply cost (i.e., "Henry Hub + y") plus total transport cost on

Pipeline 1 and Pipeline 2 (i.e., “$E + $F”). Finally, Path C consists of a Marcellus Shale gas supply, which is priced at Henry Hub minus a basis differential of “z” and is transported on Pipeline 1 for a total landed cost comprised of the gas supply cost (i.e., “Henry Hub – z”) and the transportation cost for Pipeline 1 (i.e., “$G”).

To evaluate various natural gas supply resources on an initial quantitative basis, the landed cost analysis is used to calculate the delivered costs of alternative supply paths to Northern’s service territory. The approach to assumptions and calculations the Company uses to conduct the landed cost analysis are discussed further below.

The first step in developing the landed cost analysis is to identify alternative gas supply options and transportation paths to Northern’s service territory. For each supply option, the supply cost in terms of Henry Hub plus or minus a basis differential is estimated. The next step is to calculate the pipeline transportation cost for each transportation path, based upon proposed project rates, such as may be provided in a capacity open season notice, or internal estimates. Variable and fuel costs for each alternative transportation path are typically based upon tariff rates or capacity open season notice. The landed cost approach assumes that the pipeline demand charge is evaluated at a 100% load factor (i.e., the transportation path is used every day at full volume) and variable and/or fuel charges are based on full contracted volumes. This evaluation technique can also be applied to less than 100% load factor utilization scenarios. The Company has also utilized 5-month (November through March) and 3-month (December through February) baseload utilization profiles, which are especially appropriate as the need for Incremental Supply is during the Winter Period.

3. Decision-Making Process

Northern utilizes both quantitative and qualitative tools in making resource decisions. Quantitative tools are used to assess utilization of possible resources, including impact on the utilization of other portfolio resources, to estimate average delivered costs and to assess the impact of a potential resource in satisfying or contributing to unmet design Planning Load requirements. Once reasonably available projects are identified, they are compared using the Landed Cost analysis, and then modeled as described below. In cases where there is only one available resource, Northern’s quantitative tools are used to assess the resource relative to continuing to purchase Delivered Supply in terms of providing adequacy of resources and to access cost impacts.

So long as viable available projects are comparable in terms of price, Northern bases proposed resource decisions primarily on qualitative or non-price criteria. Thus, while resource decisions are informed by quantitative analyses (such as Modeled Cost Analysis) they are not driven by the results of such analyses. As mentioned, this approach recognizes that many operational characteristics and selection criteria such as added diversity or project risk cannot be adequately modeled. Northern’s decision-making approach recognizes that price forecasts are subject to change in unpredictable ways and therefore reduces the possibility that major resource decisions are based primarily on price forecasts.

Lastly, Northern also considers the regulatory environment within which it operates (at the state level) when making resource decisions, as discussed in Part D. The evaluation framework developed by Northern provides a comprehensive and robust comparison of resource alternatives intended to inform Northern's decision making, and to demonstrate that Northern's decisions are reasonable.

4. Qualitative Assessment

As discussed above, proposed resource additions are based primarily on qualitative criteria so long as the modeled cost of competing alternatives is comparable. Qualitative analysis is used to assess non-price impacts of proposed resources, including those identified in New Hampshire RSA 378:38. The qualitative analysis allows the Company to evaluate and assess resource options across various metrics to ensure the viability and effectiveness of proposed resources and to minimize negative impacts on customers and the communities the Company serves.

The qualitative assessment includes categories such as the following:

<u>Upstream/Downstream Issues</u>: Pipeline projects will not only be assessed on their own merits, but will also include a review of issues on pipelines that are either upstream or downstream of the pipeline project under review. For example, a review of an expansion on Pipeline A that receives all of its natural gas supply from Pipeline B necessitates a need to review the attributes of Pipeline B. Assessment of locational deliverability is a critical downstream issue that applies to pipeline resources and non-pipeline supply resources such as LNG or RNG facilities. Incremental resource decisions include assessment of the ability of the resulting portfolio to deliver to the specific areas the Company serves.

<u>Project Development Risks and Deployment Timing</u>: Each pipeline project, or on-system peaking facility project, will likely present a unique set of commercial and regulatory issues that need to be assessed. Project development risks include the risk that the developer is delayed in securing or unable to secure needed approvals, financing or materials, land or labor for construction, which would require cancellation of the project. The evaluation of these issues and the ability and track record of the developer to address each issue is a critical consideration. In its evaluation of additional pipeline or LNG capacity the Company carefully considers the risk that a project may be delayed or never brought into commercial operation. Deployment timing is an important consideration because some resources take longer than others to implement, and different resources may face different development risks that ultimately impact deployment. For example, while very scalable, pipeline expansion capacity can take approximately 4 years or more to bring into service.

<u>Mitigation of Price Volatility</u>: Possible projects are reviewed in terms of whether they help to mitigate price volatility. The Company seeks to move its receipt points away from locations where gas prices are high and/or volatile and toward receipt points where gas prices are low and/or stable. Similarly, being able to replace winter period purchases with purchases made during the summer when prices are typically lower and more stable offer price volatility mitigation.

Contributions to Flexibility and Diversity: The Company seeks and values diversity among supply basins and diversity among delivering pipelines. Pipeline projects that add diversity by providing access to gas supply areas to which the Company has limited access are likely to add value to the portfolio. Similarly, projects that deliver along paths where the Company currently has limited volume can improve reliability of supply by adding diversity to the mix of delivering pipelines the Company relies upon.

Contract Renewal Rights: The flexibility of the renewal provisions of contracts, and conversely the permanence of project rights, are assessed. Renewable access to capacity is highly valued in support of fuel security and sustainable resources. Renewal options provide tools to manage long term changes that may arise.

Rate/Toll and Cost Sharing: Pipeline projects may provide potential shippers with options regarding rates/tolls. For example, a pipeline may offer a fixed toll for a set time period with a construction cost sharing mechanism; or a cost of service toll, which could change over time. The flexibility and transparency of the pipeline rate/toll approaches will be considered in the qualitative analysis.

Demand Charge Mitigation: The ability of Northern to mitigate demand charges by re-selling the pipeline capacity is another qualitative consideration. For example, pipeline capacity that has access to various markets and counterparties can be expected to provide value when the capacity is not utilized at 100% load factor.

Non-Pipeline Alternative Opportunities: Incremental supply resources or projects may present opportunities to improve overall outcomes for customers. When assessing potential supply resources, the Company will consider whether modifications to the proposed project, such as the interconnection location, could improve the economics of the project or reduce the need for identified system investments by the Company in other areas. Any such avoided expenses that may be identified would be considered when making resource decisions.

Environmental Impact: When considering new supply-side resources, the Company will inquire with developers about their efforts to mitigate environmental impacts of the construction and operation of prospective new facilities. The Company will compare the expected environmental impacts of potential supply-side resources and consider this information when making supply-side decisions. For projects that resources with differing emissions impacts, the Company will estimate relative emissions levels of greenhouse gas and air quality pollutants and associated public health and social costs, and consider this information when making resource decisions.

Economic Development and Jobs: Low and stable priced natural gas is expected to have a positive impact on the local economy. When considering new resources that involve local construction and or operation, the Company will inquire with developers about the expected impact of their project on local employment associated with the construction and operation of prospective new facilities and other economic development impacts. The Company will compare expected local economic impacts of potential resources and consider this information when making resource decisions.

Health & Safety: Northern takes its responsibility for public safety seriously, and recognizes that maintaining the reliability of our system is paramount to maintaining the public's trust. When considering new supply-side resources, the Company will inquire with developers about their efforts to mitigate health and safety impacts of the construction and operation of prospective new facilities, including impacts to public health. The Company will compare the expected health and safety impacts of potential supply-side resources and consider this information when making supply-side decisions.

5. Modeled Cost Analysis

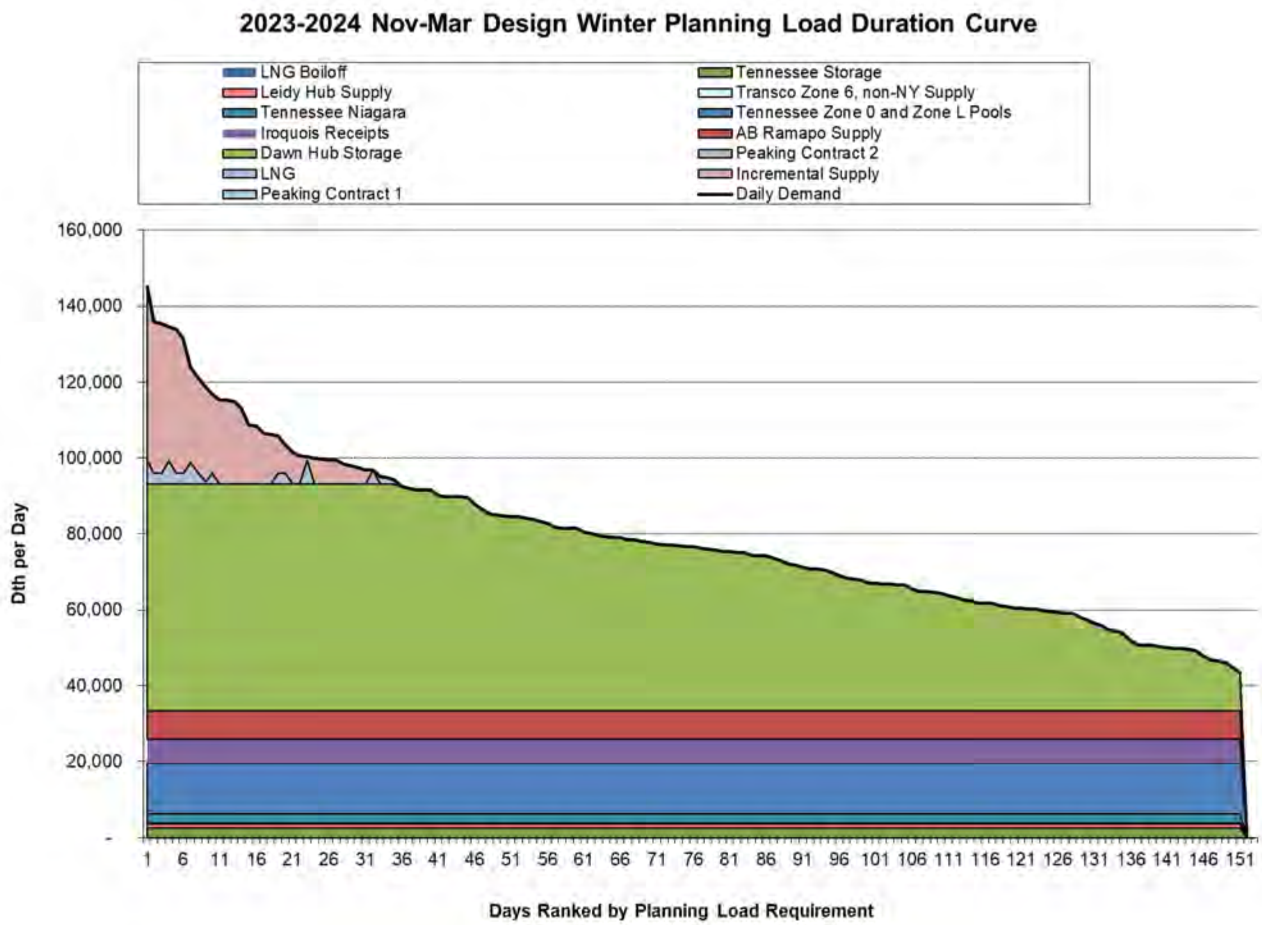
The first steps in long-term planning are to assess the adequacy of the existing portfolio and identify whether an incremental resource need exists. If a need exists, the characteristics of the need must also be assessed. The adequacy of the long-term portfolio is assessed by comparing supply available from existing resources to the Long-Term Planning Load forecast. Northern presented its Resource Balance analysis in Section VIII. For example, the Resource Balance showed that Northern has a Design Day deficiency of approximately 52,000 Dth in 2027/28.

In order to more closely evaluate incremental resource need, Northern modeled its existing long-term portfolio using PLEXOS® with an added resource modeled to dispatch after the existing resources. In this way, Northern was able to analyze the difference between supply available from the current portfolio and Long-Term Planning Load requirements on a daily basis. In developing the analysis, Northern structured the daily distribution of Planning Load on the basis of historically observed weather patterns to include a design day, a 10-day Cold Snap, design winter and normal summer[109] as described in Section VI, Planning Load. Thus, a single model run tests for resource need against design day, design year and cold snap criteria.

Using the results of the modeling described above, Northern prepared seasonal load duration curves for the five years of the planning period. Seasonal load duration curves were prepared because of the seasonal changes in Northern's portfolio. Figure XI-1 provides the design winter load duration curve for 2023/24. Winter and summer load duration curves for the five year planning period are provided in Appendix 5, Supplemental Materials for the Preferred Portfolio Section. In the load duration curve, the incremental resource need is defined by the pink colored area labeled "Incremental Supply."

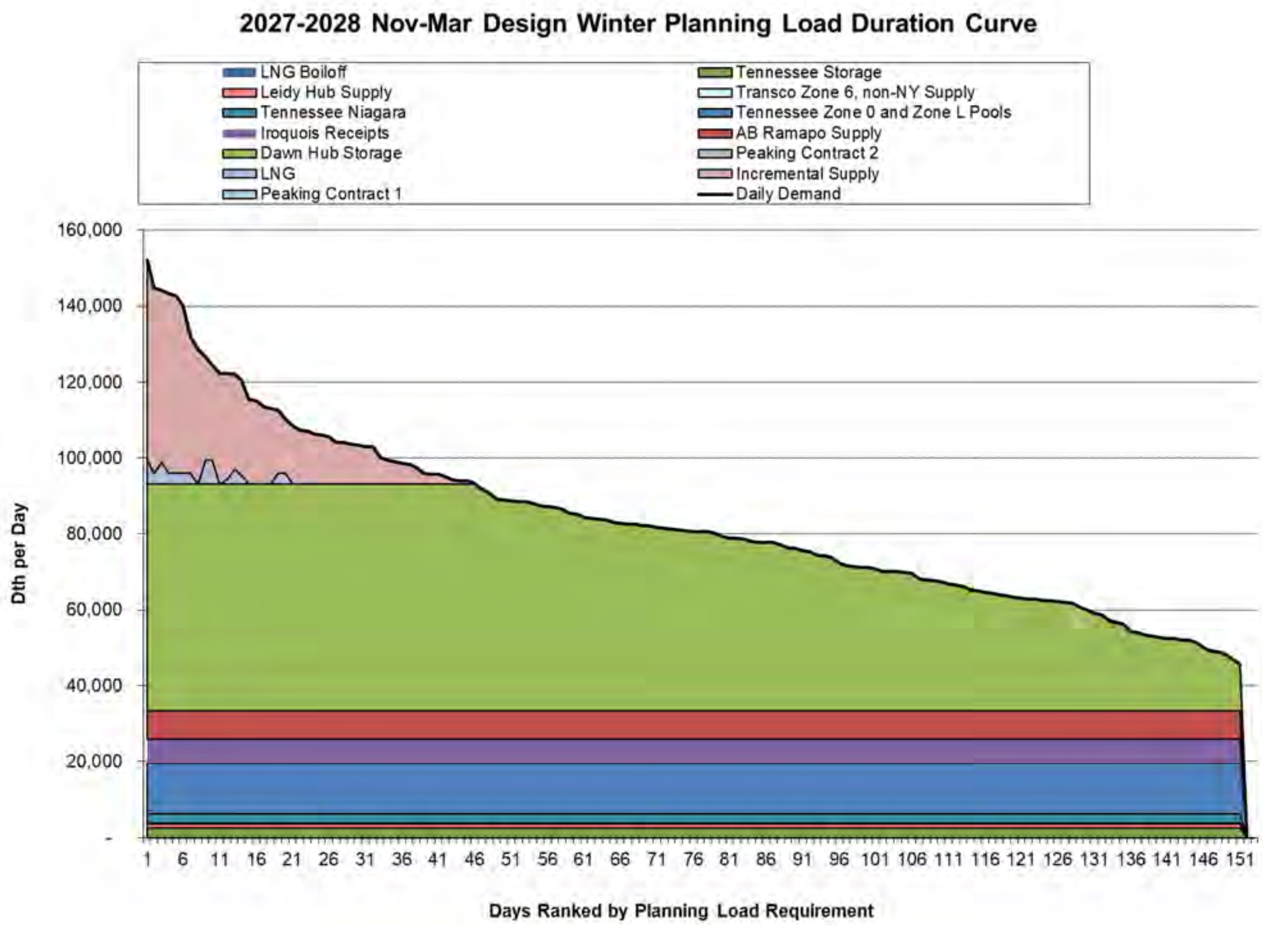
[109] Northern defines a Design Year as a design winter plus a normal summer.

Figure XI-1: Load Duration Curve, Design Winter 2023/24



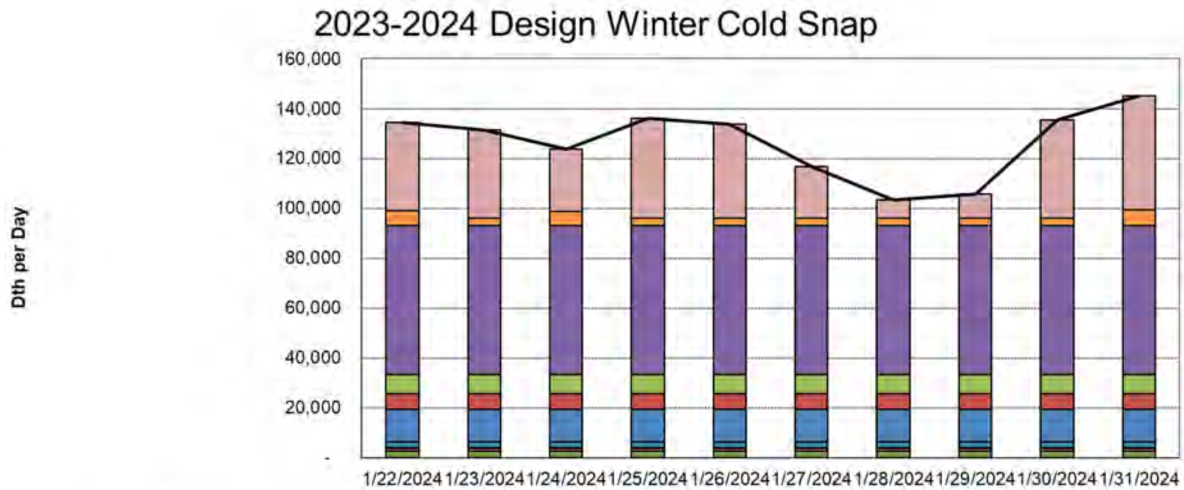
Load duration curves provide an informative depiction of incremental resource needs. Based upon visual inspection of the load duration curve, the existing portfolio would be unable to meet design planning load requirements for the coldest 35 days of the winter period, with some requirements offset by LNG production. Without conducting any further quantitative analysis, the area for Incremental Supply indicates a significant peaking need and additional need that could be met with either storage or pipeline capacity. In the recent years, Northern has made commitments to pipeline capacity, as discussed in Section VII, Current Portfolio, and in the near term plans to meet the resource need with short-term Delivered Supply resources delivered to its system by others. Figure XI-2 provides the Design Winter load duration curve for 2027/28, the fifth year of the planning period. The existing portfolio would be unable to meet the design year planning load requirements for the 46 coldest days of the design year.

Figure XI-2: Load Duration Curve, Design Winter 2027/28



In order to assess portfolio adequacy and the ability of incremental resource to contribute to portfolio adequacy, Northern models a Cold Snap Analysis. As mentioned, the cold snap analysis is embedded in the design year PLEXOS® modeling used to identify the incremental resource need. Figure XI-3 demonstrates the operation of the portfolio and the degree of incremental resource need required during the modeled cold snap for 2023/24. The chart also lists each supply modeled including the "Incremental Supply". Appendix 5 provides the cold snap analyses for the five years of the planning period.

Figure XI-3: Cold Snap Analysis, Design Winter 2023/24



	01/22/24	01/23/24	01/24/24	01/25/24	01/26/24	01/27/24	01/28/24	01/29/24	01/30/24	01/31/24
Incremental Supply	35,359	35,453	25,000	39,934	37,924	20,758	7,408	9,728	39,471	45,559
LNG	6,155	2,940	5,825	2,940	2,940	2,940	2,940	2,940	2,940	6,440
Dawn Hub Storage	59,751	59,751	59,751	59,751	59,751	59,751	59,751	59,751	59,751	59,751
AB Ramapo Supply	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Iroquois Receipts	6,434	6,434	6,434	6,434	6,434	6,434	6,434	6,434	6,434	6,434
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	60	60	60	60	60	60	60	60	60	60
Cold Snap Loads	134,590	131,468	123,900	135,949	133,940	116,774	103,424	105,743	135,487	145,074

D. Regulatory Considerations

Northern's 2023 IRP highlights the Company's efforts to comply with expectations of the Commissions that oversee the Company's procurement of supply resources, including the New Hampshire statutes under RSA 378:38.

Northern enters into transportation, storage and supply contracts on behalf of customers in order to provide reliable service at a reasonable cost. Northern expends extensive effort to assess the soundness of its decision making and by extension to provide supporting data and analysis that is adequate to allow decision makers in both states to understand and approve the cost consequences of any proposed contractual commitment.

Northern serves customers in both Maine and New Hampshire and therefore is regulated by both the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission. As part of new long-term contract decisions, Northern anticipates needing pre-approval of significant commitments and consistent treatment of new commitments in each jurisdiction, including findings that new long-term resource decisions are determined to promote the public interest, are the result of prudent utility management, and that Northern is granted approval to recover the costs associated with new long-term contracts.

Appendix 1, Supplemental Materials for the Demand Forecast Section