Northern Utilities, Inc.

2011 Integrated Resource Plan

5-Year Natural Gas Portfolio Plan

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

December 30, 2011

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I. Executive Summary

Northern Utilities, Inc. ("Northern" or "NUI") is a local distribution company providing natural gas distribution service to customers in the states of Maine and New Hampshire. Northern Utilities' predecessor companies date back over 160 years to the Portland Gas Light Company, which was formed in 1849. In 1979, Northern Utilities was acquired by Bay State Gas Company, and in 1999 Northern and Bay State Gas Company were acquired by NiSource, Inc. In 2008, Unitil Corporation purchased Northern from NiSource. Today, Northern provides natural gas local distribution service to approximately 26,500 customers in 23 communities in Southern Maine and to approximately 28,000 customers in 21 communities in the Seacoast Region of New Hampshire. The maximum aggregate daily firm throughput on Northern's system in the winter of 2010/11 (November 2010 – March 2011), was approximately 115,800 Dth, which occurred on January 24, 2011, while the total aggregate firm throughput for the entire winter was approximately 10,331,000 Dth.

In recent years, natural gas commodity prices have fallen and are near historical long-term lows while pipeline transportation rates have risen due largely to maintenance on aging systems, mandated pipeline integrity management requirements and changing market dynamics. Northern has actively participated in opposing pipeline rate increases. Delivered natural gas prices are currently favorable to competing fuels such as heating oil, and are hopefully going to remain favorable over the planning horizon due to the continuing influence of new shale gas production on wholesale market costs. As Unitil files this IRP, the natural gas industry, in general, and Northern, in particular, is presented with unique opportunities for growth and development of its natural gas distribution business. Also, Northern's commitment to upgrade its distribution system with modern, safer materials creates an opportunity to capitalize on the current price advantage of natural gas.

The Integrated Resource Plan ("IRP") relates solely to Northern's planning and contracting activities in support of the gas supply portfolio used to supply customers in the two states. The IRP is provided to explain the planning processes Northern uses to develop an adequate, reliable and economic portfolio and to allow the Public Utilities Commissions of Maine and New Hampshire to evaluate the reasonableness of those planning processes. This is the first IRP submitted by Northern since Unitil acquired Northern in December 2008.

The IRP reviews Northern's demand forecast over a five-year planning horizon, including the period of 2011/12 through 2016/17. Since Northern operates an unbundled system, whereby customers are allowed to contract for their gas supply directly with competitive suppliers, the demand forecast focuses on planning load. Planning load is the demand of customers who continue to take supply from the Company and those who receive supply from competitive suppliers but who are assigned shares of the portfolio pursuant to Northern's tariffs. Over the planning horizon, under

Northern's base case scenario, planning load is projected to increase at annual rates of 1.5 percent in Maine and 2.1 percent in New Hampshire. High case and low case scenarios were also defined as 1 percent higher and lower than the base case, respectively.

The demand forecast was calibrated with a weather sensitive model and used to project planning load requirements under extremely cold, or design, conditions over various periods of time. Northern uses a planning standard of 1 occurrence in 33 year probably, which is similar to other LDCs in the region. Forecasts of planning load demand were developed for design day, winter and year. Together with the base, high and low cases, and a cold snap scenario, these scenario forecasts formed the supply requirements against which the portfolio was assessed.

The IRP provides a review of demand-side resources, including programs offered to customers, and a discussion of current program design activity. The Company undertakes energy efficiency program planning and design in New Hampshire subject to New Hampshire Commission review and approval, however the control of the Maine programs formally reverted to the Efficiency Maine Trust effective July 1, 2011. Cost effectiveness of existing programs is reviewed, along with findings from the GDS Study and avoided cost estimates. For purposes of the IRP, demand-side resources are modeled as a continuation of current programs at currently approved budget levels and are treated as a reduction in demand requirements.

In terms of supply-side resources, Northern has access to multiple supply sources which provides for diversity of supply. Northern has the ability to source supply through three major pipelines, including Tennessee Gas Pipeline ("Tennessee"), Portland Natural Gas Transmission System ("PNGTS") and Maritimes & Northeast U.S. Pipeline ("MN U.S."), each of which can be delivered via Granite State Gas Transmission, Inc. ("GSGT"). Major supply sources connected to Tennessee include the Gulf of Mexico supply basin, Marcellus Shale and underground storage located in Pennsylvania. Tennessee also interconnects with Rockies Express pipeline (which accesses Western U.S. supplies), TransCanada and Iroquois pipelines as additional sources of supply. The PNGTS pipeline is fed by the TransCanada pipeline, which accesses supply from Western Canadian production and the Eastern Canadian storage hub. The MN U.S. pipeline accesses supply via the Sable Island production area, which is off-shore to Nova Scotia, and the Repsol Canaport LNG facility. Northern accesses these supplies via transportation capacity and upstream underground storage it holds. In addition, Northern contracts for delivered supplies on a firm basis and also utilizes the liquefied natural gas plant in Lewiston, Maine.

The IRP details Northern's current portfolio and supply management practices, including a review of recent and pending contracting decisions along with rationales for the decisions made or expected. The IRP also reviews potential incremental supplies that could be available and discusses the merits of each. Northern compared the supplies available under its existing portfolio to the design day and design year planning load forecasts over the five-year planning horizon in order to identify the current resource balance (assuming no renewal of existing contracts). Findings from this comparison indicate that Northern has adequate supplies to meet design day requirements for the current winter.

The comparison also indicates that Northern has adequate supplies under contract to meet design year requirements until year five of the planning horizon. Contract renewals and/or incremental delivered supplies are shown to be preferred resources to meet incremental requirements on the basis of Northern's resource optimization analysis, described below.

Northern conducted an analysis using the Sendout® portfolio optimization model to define a preferred portfolio capable of meeting the various demand scenarios over the planning horizon. In determining the incremental supply source that would compete against existing contracts up for renewal, Northern rejected incremental pipeline capacity on Tennessee, PNGTS and Maritimes pipelines, since Tennessee is fully subscribed, PNGTS would require upstream capacity and is very costly, and most capacity on Maritimes is controlled by merchant suppliers who also control the supply feeding the pipeline. The alternative chosen for incremental capacity into Northern's distribution system was purchasing a delivered product from parties that have unutilized pipeline capacity. Thus, in the analysis, each contract renewal competed against the purchase of delivered gas.

Based on Northern's resource optimization analysis, Northern expects that it will renew most of the pipeline and storage supply-side resources up for renewal during the five-year planning period since these resources compare favorably to purchasing delivered supplies. The IRP is intended to demonstrate the decision making process. Future renewal decisions will be based on updated market and projected demand information. The IRP details the results of the optimization analysis in terms of costs, volumes and unit cost on both a variable cost and total cost basis, and also provides load duration curves for each winter of the planning horizon under each scenario studied.

Northern looks forward to the review process and welcomes feedback from the Commission staffs and intervenors that may help shape Northern's approach to accessing available markets in an adequate, reliable and economic manner.

II. Introduction

Northern Utilities, Inc. ("Northern" or "NUI") is a local distribution company providing natural gas distribution service to customers in the states of Maine and New Hampshire. Northern Utilities' predecessor companies date back over 160 years to the Portland Gas Light Company, which was formed in 1849. In 1979, Northern Utilities was acquired by Bay State Gas Company, and in 1999 Northern and Bay State Gas Company were acquired by NiSource, Inc. In 2008, Unitil Corporation purchased Northern from NiSource. Today, Northern provides natural gas local distribution service to approximately 26,500 customers in 23 communities in Southern Maine and to approximately 28,000 customers in 21 communities in the Seacoast Region of New Hampshire. The maximum aggregate daily firm throughput on Northern's system in the winter of 2010/11 (November 2010 – March 2011), was approximately 115,800 Dth, which occurred on January 24, 2011[1], while the total aggregate firm throughput for the entire winter was approximately 10,331,000 Dth[2].

In recent years, natural gas commodity prices have fallen and are near historical long-term lows while pipeline transportation rates have risen due largely to maintenance on aging systems, mandated pipeline integrity management requirements and changing market dynamics. Northern has actively participated in opposing pipeline rate increases. Delivered natural gas prices are currently favorable to competing fuels such as heating oil, and are hopefully, going to remain favorable over the planning horizon due to the continuing influence of new shale gas production on wholesale market costs. As Unitil files this IRP, the natural gas industry, in general, and Northern, in particular, is presented with unique opportunities for growth and development of its natural gas distribution business. Also, Northern's commitment to upgrade its distribution system with modern, safer materials creates an opportunity to capitalize on the current price advantage of natural gas. Retail Choice Environment

Northern provides "bundled" firm delivery and gas supply service or "unbundled" firm delivery service in accordance with tariffs and rates approved by the Maine Public Utilities Commission ("MPUC") and New Hampshire Public Utilities Commission ("NHPUC") to residential heating, residential non-heating, Commercial and Industrial ("C&I") high winter use and C&I low winter use customers. Northern also provides service to several extra-large industrial customers in accordance with special contracts. Although historically, Northern had provided both firm and interruptible service, as of late 2010, all interruptible customers had either converted to firm service, or left the system.

Northern's C&I customers in both Maine and New Hampshire that elect to use Northern's unbundled delivery service purchase their natural gas supplies from a competitive supplier[3]. In accordance with Northern's Delivery Service Terms and Conditions, a portion of Northern's supply resources are "assigned" to transportation customers and Northern's resource planning process reflects

1 The January 24, 2011 EDD was 63.

2 Aggregate daily firm throughput includes sales and transportation load, Special Contracts, and Company Use, for both the Maine and New Hampshire Divisions.

3 Customers who elect unbundled delivery service remain transportation customers of Northern.

its obligation to hold capacity that will be assigned to transportation customers. As will be discussed in Section III, the loads associated with Northern's obligation to provide capacity for all sales customers plus the loads associated with assigned capacity is known as "Planning Load".

On an annual basis, retail choice accounts for approximately 60 percent of Maine total distribution system deliveries and 50 percent of New Hampshire total distribution deliveries. Northern's capacity assignment programs mitigate the impact of retail choice on Northern's remaining sales service customers, by requiring retail suppliers to pay a pro-rated share of Northern's fixed gas supply demand costs either through release of capacity to the competitive supplier or by the sale of company-managed supply to the competitive supplier. Without capacity assignment, retail choice would result in higher cost of gas rates to bundled sales service customers[4]. Capacity assignment also provides a means of assuring that retail suppliers have access to adequate supplies to cover the Company's design day, cold snap and year criteria.

Retail Choice impacts portfolio management over both the long- and short-term planning horizons. The long-term planning impact requires that the Company's resource portfolio be adequate to meet both sales service and capacity-assigned customer demands. The short-term planning impact requires management of Northern's capacity release and company-managed supply obligations pursuant to its capacity assignment programs and accounting for increases or decreases in the overall levels of retail choice in the Company's daily, monthly and seasonal physical commodity purchases, as well as the Company's financial hedging activities.

A. Structure of the Filing

The substance of the IRP filing is comprised of four main sections. The Section III, the Demand Forecast section provides the process and results of the firm Planning Load requirement over the long-term planning horizon under normal weather conditions. Section IV, the Planning Standards and Design Forecasts section of the IRP provides the Company's analysis and results for the determination of design weather scenarios and the presents the design year and design day Planning Load requirements for the five-year planning period, covered in this IRP. Section V, the Demand Side Management section of the IRP provides a review of the programs available to customers and describes how demand-side resources are modeled for forecasting and supply planning processes. Section VI, the Resource Portfolio Assessment section of the IRP provides a review of the Company's current resource portfolio and an overview of the Company's resource contracting decision process, as well as the results of the resource optimization analysis, prepared for this IRP. The scope of each of these sections is reviewed below.

The Demand Forecast section describes the forecast methodology, assumptions, and Normal Year results over the five-year planning horizon covering the gas years 2011/12 through 2015/16. The Demand Forecast provides the normal year Planning Load requirement, which is relied upon as a basis

[4] The level of such mitigation in Maine is unclear since only fifty percent of each transportation customer's TCQ is matched with assigned capacity.

for resource decision making. Planning Load is total load, less the load of capacity exempt customers, for which Northern does not plan. Forecast Planning Load was determined by combining (a) Customer Segment demand forecasts; (b) minus capacity exempt demand; (c) minus incremental savings expected from the Company's existing energy efficiency programs; (d) plus projected demand growth from the marketing efforts; (e) plus adjustments for Company Use, losses and unbilled sales. The Normal Year Planning Load forecast for each Division is thus equal to the sales demand plus capacity assigned transportation demand adjusted for Company Use, losses and unbilled sales.

The Planning Standards and Design Forecasts section describes the derivation of the Planning Load requirement associated with extreme cold weather conditions, specifically for Design Year and Design Day. Historical weather data, measured in Effective Degree-Days ("EDD"), are examined for evidence of climate change and for being normally distributed statistically. As a result of the climate change analysis, Northern decided to use the past 20 years of weather data in determining design condition EDD. EDD data were found to be normally distributed. The Customer Segment firm demand and Company Use forecasts were re-calculated for 1-in-33 year planning standard to establish design weather forecasts. The Company's analysis of the required resources to meet the firm Planning Load requirements associated with normal and design weather conditions is presented in Section VI.

The Demand Side Resources section reviews the Company's practices regarding program design and implementation, and reviews existing programs and their historical and projected energy efficiency savings, which are reflected as a reduction to the demand forecast. The potential for expanded efficiency savings is reviewed using data from the GDS Study. Natural gas avoided costs are also reviewed. The Company provides an analysis of the potential costs and savings associated with expanded energy efficiency programs.

The Resource Assessment section of the IRP lays out the process for making long-term supply-side resource decisions required to meet Northern's Planning Load requirements. The Resource Assessment provides an overview of Northern's current supply resources, supply procurement and financial hedging practices and discusses the flexibility of Northern's portfolio. A Resource Balance is presented, which provides a comparison of Northern's current supply portfolio (assuming no renewals) to the projected Design Day, Design Year and Design Winter Planning Load requirements throughout the planning period for this IRP, as determined in the Demand Forecast section. Next, the Supply Resource Alternatives are presented, including existing contract renewals and resources that would be new to Northern. The Resource Optimization Analysis provides an overview of Northern's supply-side modeling assumptions and process and the results of Northern's analysis, including both projected costs and supply sourcing, as well as Northern's preferred portfolio and indicated contract decisions. Finally, the Resource Assessment provides a Cold Snap Analysis.

The final section, Compliance with Directives, compares the terms of the Settlement Agreement, approved in Docket No. 2006-390 and Docket No. DG 06-098, to the materials provided in the IRP.

III.Demand Forecast

A. Overview

The forecast of firm Planning Load requirements over the long-term planning horizon is an integral part of the development of Northern's IRP that serves as the basis for the evaluation of resources and subsequent resource decisions. Section III of this IRP describes the forecast methodology, assumptions, and Normal Year results over the five-year planning horizon covering the gas years 2011/12 through 2015/16.[5] The forecast was prepared by Concentric Energy Advisors, Inc. ("Concentric"), which is a management consulting and economic advisory firm based in Marlborough, Massachusetts.

This Demand Forecast section is organized as follows:

Forecast Methodology and Results: Presents an overview of the forecasting process and key results from the forecast.

Customer Segment Forecasts: Describes the forecasting methodology, regression equations, results and analysis for each Customer Segment. This section includes a discussion of data sources used to develop each forecast, including customer data, weather data, and economic/demographic data.

Normal Year Firm Planning Load Forecast: Describes the calculation of the Normal Year Planning Load forecast. This section also contains a discussion of the High and Low Growth scenarios.

In addition to a Normal Year forecast, demand forecasts under extreme weather conditions, referred to as "Design Year", "Design Day" and "Cold Snap" were prepared and are discussed in Section IV, "Planning Standards and Design Forecasts". In addition to the narrative and tables included in this report, complete forecast result tables are included in Appendix III along with the statistical documentation and other supporting information.

B. Forecast Methodology and Results

1. Overview of Methodology

The long-term natural gas demand models that were developed for the 2011/12 through 2015/16 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 forecast methodology, models, and results.

[5] Gas year (or "split year") is defined as November through the following October, unless otherwise stated.

This IRP uses the definitions listed in Table III-1 below to refer to and distinguish between different types of natural gas demand.

Table III-1: Forecast Terminology[6]

Term	Definition
Demand, Usage, or Load	Generic terms that refer to the gas used by customers to meet their energy requirements.
Customer Segment Demand	Total firm sales plus total transportation demand for a customer group, which is a defined group of customer classes (measured at the customer meter on a billing period basis).
Throughput	Total usage measured at the gate station on a calendar period basis; throughput includes sales plus total transportation gas usage measured at customers' meter, Company Use, losses and unbilled sales.
Capacity Exempt Load	Load for transportation customers that are not subject to the capacity assignment rules, which are included in Northern's tariffs
Capacity Assigned Load	Portion of load for which capacity is assigned to transportation customers that are subject to Northern's capacity assignment rules.
Non-Capacity Assigned Load	Portion of load for which capacity is not assigned to Maine transportation customers that are subject to capacity assignment rules. (This term is not applicable to New Hampshire.)
Planning Load	Total sales plus capacity assigned transportation usage measured at the gate station on a calendar period basis (i.e., includes Company Use, losses and unbilled sales) – excludes capacity exempt and non-capacity assigned transportation usage.

The 2011/12 through 2015/16 demand forecast is used to determine the Planning Load over the forecast horizon, since that is the load for which the Company must procure resources. As previously described, Planning Load includes all firm sales demand and all capacity assigned firm transportation load, measured at the gate station (i.e., including Company Use, losses and unbilled sales). Capacity assigned transportation load represents the usage associated with transportation customers that are included in the Company's mandatory capacity assignment process. The Delivery Service Terms and Conditions specify (1) those transportation customers that are eligible for assigned capacity, and transportation customers that are exempt from the capacity assignment rules[7]; (2) the categories of Northern's supply resources that will be assigned; and (3) the basis for the charges for the assigned

[6] Since Northern does not have any interruptible customers at this time, these definitions unambiguously refer to firm service; therefore the term "firm" is not always expressly stated.

[7] These capacity assignment rules are different in Maine and New Hampshire.

capacity. The Company retains the obligation to provide resources for capacity assigned transportation customers in addition to all sales customers; therefore, establishing an appropriate forecast of Planning Load, under normal and design weather conditions, and high and low growth scenarios, is the primary objective of the demand forecast.

Separate forecasts were developed for Northern's Maine and New Hampshire Divisions using the same process. For each Division, quarterly demand forecasts for each Customer Segment were developed 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. Planning Load is total load, less the load for capacity exempt customers, which Northern does not plan for. Forecast Planning Load was determined by combining (a) Customer Segment demand forecasts; (b) minus capacity exempt demand; (c) minus incremental savings expected from the Company's existing energy efficiency programs;[8] (d) plus projected demand growth from the Company's marketing efforts; (e) plus adjustments for Company Use, losses and unbilled sales. The Normal Year Planning Load forecast for each Division is thus equal to the sales demand plus capacity assigned transportation demand adjusted for Company Use, losses and unbilled sales.

2. Overview of Normal Year Forecast Results

Over the forecast period, Planning Load (i.e., total sales and capacity assigned transportation demand adjusted for Company Use, losses and unbilled sales) is projected to increase at an average annual rate of 1.5% in the Maine Division, and increase at an annual rate of 2.1% in the New Hampshire Division, under Base Case normal weather conditions. The Planning Load forecast is summarized in Table III-2 – Maine Division and Table III-3 – New Hampshire Division below.

[8] Expected energy efficiency savings are those savings associated with existing approved energy efficiency programs and budget levels, extrapolated through the forecast period. Energy efficiency programs refer to energy efficiency programs funded through charges to Northern's natural gas customers.

Table III-2: Base Case Normal Year Planning Load Results (Dth) – Maine Division

Split Year	Residential	C&I Sales plus Capacity Assigned[9]	SUBTOTAL: Sales plus Capacity Assigned (before adjustments)	Energy Efficiency Adjustment	Marketing Adjustment	Company Use	Losses and Unbilled Sales	Planning Load
2011/12	1,157,708	3,404,864	4,562,572	-10,956	75,441	7,141	199,451	4,833,649
2012/13	1,164,836	3,378,787	4,543,623	-21,780	146,215	7,143	201,794	4,876,995
2013/14	1,181,967	3,371,761	4,553,728	-32,457	215,714	7,143	205,053	4,949,181
2014/15	1,209,920	3,378,622	4,588,542	-42,983	285,385	7,143	209,290	5,047,377
2015/16	1,237,362	3,378,258	4,615,621	-53,291	353,942	7,143	213,371	5,136,786
CAGR (11/12-15/16)	1.7%	-0.2%	0.3%	48.5%	47.2%	0.0%	1.7%	1.5%

Table III-3: Base Case Normal Year Planning Load Results (Dth) – New Hampshire Division

Split Year	Residential	C&I Sales plus Capacity Assigned[10]	SUBTOTAL: Sales plus Capacity Assigned (before adjustments)	Energy Efficiency Adjustment	Marketing Adjustment	Company Use	Losses and Unbilled Sales	Planning Load
2011/12	1,684,604	3,475,564	5,160,169	-24,863	69,031	631	90,865	5,295,833
2012/13	1,698,182	3,475,651	5,173,832	-41,914	133,248	631	92,670	5,358,466
2013/14	1,728,979	3,497,636	5,226,615	-58,962	198,996	631	94,246	5,461,526
2014/15	1,778,152	3,547,697	5,325,849	-76,003	268,427	631	96,225	5,615,129
2015/16	1,826,519	3,584,077	5,410,596	-93,039	339,086	631	98,718	5,755,992
CAGR (11/12-15/16)	2.0%	0.8%	1.2%	39.1%	48.9%	0.0%	2.1%	2.1%

[9] C&I sales plus capacity assigned load includes capacity assigned Special Contract demand.

[10] C&I sales plus capacity assigned load includes capacity assigned Special Contract demand.

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 quarterly forecast models for the following Customer Segments:

- Residential Heating
- Residential Non-Heating
- C&I Low Load Factor Sales and Transportation (i.e., primarily heating loads) ("LLF")[11]
- C&I High Load Factor Sales and Transportation (i.e., primarily process loads) ("HLF")
- Special Contracts

The demand forecast for the four Residential and C&I Customer Segments is based on separate econometric models for number of customers and use per customer; in total, eight separate Residential and C&I models plus additional special contract load models were developed for each Division. The total demand forecast for the Residential and C&I Customer Segments is determined by multiplying the forecasted results from the number of customer model by the forecasted results from the use per customer model by quarter. Total demand for the C&I and Special Contract[12] Customer Segments was separated into (1) sales plus capacity assigned transportation, and (2) capacity exempt and non-capacity assigned transportation using projected ratios of capacity exempt demand and capacity assignment program assumptions.

Regression analysis, based on accepted statistical techniques, was used to develop the Customer Segment demand forecast models.[13] For the Customer Segment forecasts, regression analysis was used to predict quarterly use per customer and number of customers by Customer Segment based on predicted values of various external variables (e.g., weather, price of natural gas, employment levels, and population); in regression analysis terms, use per customer and number of customers are the "dependent variables" and the various external variables are the "independent variables." The Customer Segment dependent variables for each Division were based on historical billing quarter data that were derived from Northern recorded billing month data. The Customer Segment models were

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11 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.

12 Separate demand models were developed for each of the Special Contract customers.

13 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.

estimated using dependent and independent quarterly data from the first quarter of 2005 through the first quarter of 2011 (i.e., 2005 Q1 through 2011 Q1). To compute the Base Case forecasts under normal weather conditions, forecasted independent variable values for 2011 Q2 through 2016 Q4 were applied to the Customer Segment models.

The Planning Load forecast for each Division also includes forecasts of Company Use, energy efficiency savings from existing programs, expected incremental demand from the Company's marketing efforts, losses and unbilled sales. The sum of the sales plus capacity assigned Customer Segment forecast plus Company Use, energy efficiency savings, marketing adjustment, losses and unbilled sales produces the Planning Load forecast for each Division.

All regression analyses were conducted using the PASW/SPSS™ (Release 18.0.0) software package. Appendix III-5 provides a description of the modeling process used to develop each of the Customer Segment models.

2. Description of the Data

Five general data and variable categories were used in the development of the Customer Segment forecasts; the categories are described below, and the variables that were considered in the development of the Customer Segment models are listed and defined in Appendix III-2.

a) Customer Segment Data

Historical monthly billing data that was derived from Company records for each Division by customer class for the period January 2005 through March 2011 includes demand, measured in therms or ccf; number of customers; and bundled revenue by rate class for each Division. This data was aggregated into the five 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 on one of Northern's high winter use rate schedules, whereas the C&I High Load Factor Customer Segment is comprised of C&I customers that are served on one of Northern's low winter use rate schedules. The customer classes that are in each Customer Segment for each Division are shown in the table below:

Table III-4: Customer Segment Definitions

Class ME	Class NH	Class Description	Customer Segment
R-2	R-5,R-10	Residential Heating	Residential Heating
R-1	R-6,R-11	Residential Non-Heating	Residential Non-Heating
G-40	G-40	C&I Sales Low Annual Use, High Peak Period/ Winter Use	C&I Low Load Factor
G-41	G-41	C&I Sales Medium Annual Use, High Peak Period/ Winter Use	
G-42	G-42	C&I Sales High Annual Use, High Peak Period/ Winter Use	
T-40	T-40	C&I Transport Low Annual Use, High Peak Period/ Winter Use	
T-41	T-41	C&I Transport Medium Annual Use, High Peak Period/ Winter Use	
T-42	T-42	C&I Transport High Annual Use, High Peak Period/ Winter Use	
G-50	G-50	C&I Sales Low Annual Use, Low Peak Period/ Winter Use	C&I High Load Factor
G-51	G-51	C&I Sales Medium Annual Use, Low Peak Period/ Winter Use	
G-52	G-52	C&I Sales High Annual Use, Low Peak Period/ Winter Use	
T-50	T-50	C&I Transport Low Annual Use, Low Peak Period/ Winter Use	
T-51	T-51	C&I Transport Medium Annual Use, Low Peak Period/ Winter Use	
T-52	T-52	C&I Transport High Annual Use, Low Peak Period/ Winter Use	
SPC	SPC	Special Contracts	Special Contracts

The monthly billing data was adjusted as necessary[14], aggregated into Customer Segments, and summarized into billing quarters to be used in the quarterly Customer Segment models.[15]

b) Weather Variable

Historical daily effective degree day ("EDD") data for November 1, 1970 through March 31, 2011 was provided by the Company for the Maine Division (measured at the Portland, Maine weather station) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station).

[14] Adjustments include converting Maine demand data from Mcf to Dth, and various billing adjustments.

[15] Quarterly models were developed based on calendar year quarters (Q1 = January, February, March; Q2 = April, May, June; Q3 = July, August, September; and Q4 = October, November, December).

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.[16]

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; approximately equal numbers of Northern's customer meters are read every working day of the month. As a result, most of the consumption in the first billing cycles of a billing month occurs in the prior calendar month, and most of the consumption in the last billing cycles of a billing month occurs in the same calendar month. In general terms, consumption in each billing month is affected by EDD as measured in each day of the same month and the prior month. A billing month EDD variable was developed to match the pattern of billing month demand measured by billing cycle. The methodology that was used to calculate billing month EDD data, based on daily EDD data, is illustrated in Appendix III-3.

Historical billing month EDD values for the period January 2005 through March 2011 were calculated, and aggregated by quarters; the historical quarterly EDD data was used to measure the effect of temperature on natural gas use in the Customer Segment use per customer models.[17]

c) Economic and Demographic Variables

Economic activity and demographic data to be used in the regression analysis were acquired from IHS Global Insight, Inc. ("Global Insight"). Global Insight provided separate data series for the Maine and New Hampshire Divisions. Historical quarterly data included 2005 Q1 through 2011 Q1 (the "historical period") and quarterly forecast data was provided from 2011 Q2 through 2020 Q4. The data include fuel prices, employment, income, population, and housing statistics specific to counties that Northern serves in Maine and New Hampshire, as well as state level data for Maine and New Hampshire. The Maine Division variables are derived from data for the Lewiston-Auburn and Portland-South Portland metropolitan areas; these areas most closely correspond to Northern's Maine service territory. The New Hampshire Division variables were derived from data for Rockingham County and Strafford County; these counties most closely correspond to Northern's New Hampshire service territory. Table III-5 summarizes the Global Insight quarterly economic and demographic data used in developing the Customer Segment models.

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16 The Company used the average temperature and wind speeds to produce daily EDD for each Gas Day for 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

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

Table III-5: Global Insight Variables

Lewiston-Auburn and Portland- South Portland metropolitan areas, Maine; and Rockingham and Strafford Counties, New Hampshire:
Total Population (Thousands)
Households (Thousands)
Housing Stock (Units)
Housing Starts, Total Private
Mortgage Originations – New Homes (Millions $)
Mortgage Originations – Total (Millions $)
Employment, Total Non-farm (Thousands)
Employment, Non-manufacturing (Thousands)
Employment, Total Service Providing Private Employment (Thousands)
Employment, Manufacturing (Thousands)
Average Household Income (Thousands $)
Real Per Capita Personal Income (Thousands 2005$)
Real Retail Sales (Millions 2005$)
Real Gross Metropolitan Product (Millions 2005$)
State of Maine and State of New Hampshire:
Average Retail Price of Natural Gas, Residential ($/MMBtu)
Average Retail Price of Natural Gas, Commercial, ($/MMBtu)
Average Retail Price of Natural Gas, Industrial, ($/MMBtu)

d) Natural Gas Price Variable

Because economic theory suggests that price is likely to influence demand, natural gas price variables specific to each Customer Segment were developed for the use per customer models. Historical natural gas prices for each Customer Segment and each Division were derived from Company data. Forecasted prices, also specific to each Customer Segment and each Division, were developed using price forecasts prepared by Global Insight, together with the Company historical data. The methodology that was used to develop the natural gas price variable is described in Appendix III-4.

e) Other Variables

The following variables were derived from Global Insight data to be used in the Customer Segment models:

Variable	Derivation
Average household size	Population divided by number of households
Cumulative housing starts	Quarterly number of housing starts added to the sum of all previous housing starts
Cumulative mortgage originations	Quarterly number of mortgage originations added to the sum of all previous mortgage originations

The following variables were created by Concentric to be used in the Customer Segment models:

Variables that Global Insight provided in nominal dollars (e.g., average household income) were converted to real 2005 dollars using inflator/deflator rates for real per capita personal income provided by Global Insight.

Annual and quarterly 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 outside of that specific time.

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 one-quarter and four-quarter lags were created from several of the variables to test if the impact of that variable on the number of customers or use per customer was not immediate, but instead is delayed.

In total, 19 economic, demographic, and pricing variables (plus additional lag variables, dummy variables, and interactive variables) were tested in the development of the number of customer and use per customer models for each Division. The final equations for each Customer Segment are discussed in Section III.C.3 and Section III.C.4 for Maine and New Hampshire, respectively.

3. Customer Segment Model Results – Maine Division

This section summarizes the results of each Customer Segment model for Northern's Maine Division. Detailed statistical summaries including (a) the results of the statistical tests that were performed for each Customer Segment model, (b) historical actual data, (c) historical fitted values derived from each model, and (d) forecasted values derived from each model are provided in Appendix III-6. In addition, Appendix III-6 contains summary results for each Customer Segment for the Maine Division.

a) Residential Heating Customer Segment Forecast – Maine Division

Residential Heating is the Maine Division's largest Customer Segment in terms of number of customers, but is the fourth largest Customer Segment in terms of demand. For the historical period of 2005/06 through 20010/11,[18] the Residential Heating Customer Segment represented approximately 50% of Maine Division total customers and approximately 12% of Maine Division total actual demand. Over the same time period, the number of Residential Heating customers increased by approximately 3.4% per year[19] and weather normalized total Residential Heating demand increased by approximately 2.8% per year.[20] Currently, Residential customers are not eligible for transportation service and as a result no Residential customers are subject to the Maine conditions of capacity assignment; therefore, all Residential Heating demand is included in Planning Load.

(1) Residential Heating Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as the number of people living in the service territory (i.e., households, population, housing stock, or cumulative housing starts), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Heating customer model. In the final regression equation that was selected to predict the number of Residential Heating customers, cumulative housing starts lagged by two quarters, quarterly dummy variables, and several time-specific dummy variables were statistically significant. Over the forecast period, the number of Residential Heating customers is expected to grow at an annual rate of 2.0% as shown in Table III-6 below.

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18 For the purpose of identifying historical usage trends, the 6-year period from 2005/06 to 2010/11 was used. Please note that 2010/11 includes actual data through March 2011 and forecast data for the remainder of the split year.

19 Some historical growth rates are affected by shifts that occurred in the historical data.

20 Growth rates throughout this report are calculated as compound annual growth rates ("CAGR"), unless noted otherwise. CAGR = ((last value / first value)^(1/# of periods between last and first values)) - 1

Table III-6: Residential Heating Customer Model Forecast[21] – Maine Division

Split Year	Average Customer Forecast
2011/12	14,155
2012/13	14,364
2013/14	14,651
2014/15	14,975
2015/16	15,312
CAGR	2.0%

(2) Residential Heating Use Per Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, the average number of people per house (i.e., household size), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Heating use per customer model. In the final regression equation that was selected to predict Residential Heating use per customer, billing cycle EDD, Residential Heating natural gas price, quarterly dummy variables, and time-specific dummy variables were statistically significant. Over the forecast period, the use per customer for the Residential Heating Customer Segment is expected to remain relatively flat as shown in Table III-7 below.

Table III-7: Residential Heating Use Per Customer Model Forecast[22] – Maine Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	75.5
2012/13	75.1
2013/14	75.0
2014/15	75.3
2015/16	75.6
CAGR	0.0%

21 All number of customer forecasts are presented in split years that correspond to calendar quarters (i.e., October through September).

22 All use per customer forecasts are presented in split years that correspond to calendar quarters (i.e., October through September).

(3) Residential Heating Demand Results – Maine Division

The Residential Heating demand forecast was calculated by multiplying the forecasted number of Residential Heating customers for each quarter by the forecasted Residential Heating use per customer for that quarter. Over the forecast period, Residential Heating demand is expected to increase by approximately 2.0% per year as shown in TableIII-8 below.

Table III-8: Residential Heating Demand Forecast[23,24] – Maine Division

Split Year	Normal Year Forecast (Dth)
2011/12	1,068,246
2012/13	1,079,209
2013/14	1,099,224
2014/15	1,128,358
2015/16	1,157,468
CAGR	2.0%

The forecasted annual growth rate for Residential Heating demand of 2.0% is the net effect of the forecasted 2.0% growth in customers, and the forecasted 0.0% increase in use per customer. The primary driver of this annual demand growth is the forecasted growth in cumulative housing starts. Currently, Residential Heating customers are not eligible for transportation service; therefore, all Residential Heating demand is included in Planning Load.

b) Residential Non-Heating Customer Segment Forecast – Maine Division

Residential Non-Heating is the Maine Division's third largest Customer Segment in terms of number of customers, but the smallest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the Residential Non-Heating Customer Segment represented approximately 20% of Maine Division total customers and approximately 1% of Maine Division total actual demand. Over the same time period, the number of Residential Non-Heating customers decreased by approximately 2.2% per year and weather normalized total Residential Non-Heating demand increased by approximately 4.7% per year.

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23 All Customer Segment demand forecast results are before adjustments for energy efficiency savings, marketing, losses and unbilled sales.

24 All demand forecast split years are November through October. To develop a split year forecast for the traditional gas year (i.e., November through October), the fourth quarter results were allocated to the appropriate gas year (e.g., October of 2012 was allocated to the 2011/12 split year, while November and December of 2012 were allocated to the 2012/13 split year).

(1) Residential Non-Heating Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as the number of people living in the service territory (i.e., households, population, housing stock, or cumulative housing starts), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Non-Heating customer model. In the final regression equation that was selected to predict the number of Residential Non-Heating customers, a quarterly trend variable, a quarterly dummy variable, and several time-specific dummy variables and interactions were statistically significant. As shown below in Table III-9, over the forecast period, the number of Residential Non-Heating customers is projected to decline by 2.9% per year.

Table III-9: Residential Non-Heating Customer Model Forecast – Maine Division

Split Year	Average Customer Forecast
2011/12	4,721
2012/13	4,590
2013/14	4,459
2014/15	4,329
2015/16	4,198
CAGR	-2.9%

(2) Residential Non-Heating Use Per Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, the average number of people per house (i.e., household size), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Non-Heating use per customer model. In the final regression equation that was selected to predict Residential Non-Heating use per customer, Residential Non-Heating natural gas price, quarterly dummy variables, and time-specific dummy variables and interactions were statistically significant. Over the forecast period, the use per customer for the Residential Non-Heating Customer Segment is expected be flat as shown in Table III-10 below.

Table III-10: Residential Non-Heating Use Per Customer Model Forecast – Maine Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	19.0
2012/13	18.7
2013/14	18.6
2014/15	18.8
2015/16	19.0
CAGR	0.1%

(3) Residential Non-Heating Demand Results – Maine Division

The Residential Non-Heating demand forecast was calculated by multiplying the forecasted number of Residential Non-Heating customers for each quarter by the forecasted Residential Non-Heating use per customer for that quarter. As shown in Table III-11 below, Residential Non-Heating demand is expected to decline by approximately 2.8% per year over the forecast period.

Table III-11: Residential Non-Heating Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth)
2011/12	89,462
2012/13	85,627
2013/14	82,743
2014/15	81,562
2015/16	79,895
CAGR	-2.8%

The forecasted annual decrease in Residential Non-Heating demand of 2.8% is the net effect of the forecasted 2.9% annual decrease in the customer count and the forecasted 0.1% annual increase in the use per customer. Thus, the primary driver of the decrease in Residential Non-Heating demand is the negative trend in the number of Residential Non-Heating customers. Residential Non-Heating customers are not eligible for transportation service; therefore, all Residential Non-Heating demand is included in Planning Load.

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

The C&I LLF Customer Segment[25] is the Maine Division's second largest Customer Segment in terms of number of customers and the largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the C&I LLF Customer Segment represented approximately 22% of Maine Division total customers and approximately 42% of Maine Division total actual demand. Over the same time period, the number of C&I LLF customers increased by approximately 2.2% per year and weather normalized total C&I LLF demand increased by approximately 6.6% per year.

(1) C&I LLF Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as employment levels (i.e., total employment, non-manufacturing employment, or service employment), retail sales, or gross metropolitan product should be considered when developing a C&I LLF customer model. In the final regression equation that was selected to predict the number of C&I LLF customers, non-manufacturing employment, quarterly dummy variables, and several time-specific dummy variables and interactions were statistically significant. As shown below in Table III-12, the number of C&I LLF customers is expected to grow at an annual rate of 1.3% over the forecast period.

Table III-12: C&I LLF Customer Model Forecast – Maine Division

Split Year	Average Customer Forecast
2011/12	6,141
2012/13	6,217
2013/14	6,307
2014/15	6,391
2015/16	6,468
CAGR	1.3%

(2) C&I LLF Use Per Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, employment levels (i.e., total employment, non-manufacturing employment, or service employment), retail sales, or gross metropolitan product should be considered when developing a C&I LLF use per customer model. In the final regression equation that was selected to predict C&I LLF

25 The C&I LLF Customer Segment includes both firm sales (G-40, G-41, and G-42) and firm transportation (T-40, T-41, and T-42) customers, unless noted otherwise.

use per customer, billing cycle EDD, C&I LLF natural gas price, quarterly dummy variables, and time-specific dummy variables and interactions were statistically significant. Over the forecast period, the use per customer for the C&I LLF Customer Segment is expected to remain flat as shown in Table III-13 below.

Table III-13: C&I LLF Use Per Customer Model Forecast – Maine Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	634.0
2012/13	630.8
2013/14	630.1
2014/15	632.7
2015/16	634.6
CAGR	0.0%

(3) C&I LLF Demand Results – Maine Division

The C&I LLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF customers for each quarter by the forecasted C&I LLF use per customer for that quarter. As shown in Table III-14 below, C&I LLF demand is expected to increase by 1.3% per year over the forecast period.

Table III-14: C&I LLF Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	3,893,236
2012/13	3,921,446
2013/14	3,974,019
2014/15	4,043,709
2015/16	4,104,700
CAGR	1.3%

The forecasted annual growth rate for C&I LLF demand of 1.3% is the net effect of the forecasted 1.3% annual growth in customers and the forecasted flat use per customer. The primary driver of this annual demand growth is the forecasted growth in non-manufacturing employment.

(4) C&I LLF Planning Load – Maine Division

The Maine Division of Northern began offering unbundled sales and transportation services to all C&I customers in 1998. Pursuant to a Settlement Agreement in Docket 2005-087, Northern's resources are assigned to suppliers serving all firm transportation customers in its Maine Division except for "capacity exempt" customers that started taking transportation service after January 1, 2006 and had not taken firm sales service from the Company at any time prior, and had opted to be capacity exempt. Capacity is assigned to suppliers in the winter to meet 50% of the Design Day requirements of their customers. No capacity is assigned in the summer.[26,27] As a result of this capacity assignment process, Northern must provide capacity for 50% of the Design Day requirements of its Maine Division transportation customers in the winter, except for transportation customers that are capacity exempt.

C&I Planning Load for the Maine Division includes (1) the C&I firm sales demand, and (2) 50% of the transportation load that is subject to the capacity assignment rules in the winter; capacity exempt and non-capacity assigned transportation load is not included in the Maine Division's C&I Planning Load. In the summer, C&I Planning Load for the Maine Division includes only the C&I firm sales demand. The Planning Load associated with the C&I LLF Customer Segment for the Maine Division was determined by: (1) estimating the portions of total C&I LLF firm demand that are (a) sales and (b) transportation; and (2) estimating the portions of C&I LLF firm transportation demand that are (a) subject to capacity assignment rules and (b) capacity exempt; then (3) taking 50% of the C&I LLF firm transportation demand that is subject to capacity assignment rules.

(a) C&I LLF Firm Sales and C&I LLF Firm Transportation Demand – Maine Division

In 2010/11, approximately 59% of C&I LLF demand was firm transportation demand, and the remaining 41% was firm sales demand. Over the historical period of 2005/06 through 20010/11, C&I LLF firm transportation demand has been growing faster than C&I LLF firm sales demand.

The forecast demand for C&I LLF firm transportation was developed according to the following process. First, a regression equation was developed to predict the percentage of C&I LLF firm transportation only demand based on billing cycle EDD, annual trends, quarterly dummy variables, several time-specific dummy variables, and interactions. Second, the C&I LLF firm transportation demand forecast was calculated by multiplying the forecasted firm transportation only percentages for each quarter by the forecasted total C&I LLF demand for that quarter. Finally, the forecast of C&I LLF firm sales demand was developed by subtracting the forecast of C&I LLF transportation demand from

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[26] For a transportation customer that requests to migrate to sales service, Northern is not obligated to provide firm sales service above the level of the customer's assigned capacity unless Northern has sufficient capacity available to do so.

[27] With respect to reliability, Northern has the ability to recall capacity assigned to competitive suppliers in the event that they fail to deliver required volumes on behalf of their transporting customers.

the forecast of total C&I LLF demand. As discussed above, the C&I LLF combined firm sales and firm transportation demand is expected to increase by 1.3% per year over the forecast period. C&I LLF firm transportation demand is expected to grow by 2.7% per year, while C&I LLF firm sales demand is expected to decline by 0.7%, as shown in Table III-15 below.

Table III-15: C&I LLF Sales and Transportation Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth)		
	Total C&I LLF	Firm Transportation	Firm Sales
2011/12	3,893,236	2,243,093	1,650,143
2012/13	3,921,446	2,290,775	1,630,672
2013/14	3,974,019	2,353,787	1,620,232
2014/15	4,043,709	2,428,411	1,615,298
2015/16	4,104,700	2,498,714	1,605,986
CAGR	1.3%	2.7%	-0.7%

(b) C&I LLF Transportation Subject to Capacity Assignment Rules and Capacity Exempt Transportation Demand – Maine Division

In 2010/11, approximately 96% of the C&I LLF firm transportation demand was subject to capacity assignment rules and the remaining 4% was capacity exempt. The forecast demand for C&I LLF capacity exempt transportation was developed according to the following process. First, a model was developed to forecast capacity exempt demand as a percentage of total C&I LLF firm transportation demand based on a quarterly trend, quarterly dummy variables and billing cycle EDD. Second, the C&I LLF capacity exempt transportation demand was calculated by multiplying the forecasted capacity exempt percentages for each quarter by the forecasted C&I LLF firm transportation demand for that quarter. Finally, the forecast of C&I LLF demand that is subject to capacity assignment rules was developed by subtracting the forecast of capacity exempt transportation demand from the forecast of C&I LLF firm transportation. As discussed previously, the total C&I LLF firm transportation demand is expected to increase by 2.7% per year over the forecast period. C&I LLF demand that is subject to capacity assignment rules is expected to grow by 1.9% per year, while C&I LLF capacity exempt transportation demand is expected to increase by 14.5% per year, as shown in Table III-16 below.

Table III-16: C&I LLF Transportation Subject to Capacity Assignment Rules & Capacity Exempt Transportation Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth)		
	Firm Transportation	Capacity Exempt	Subject to Capacity Assignment Rules
2011/12	2,243,093	118,119	2,124,973
2012/13	2,290,775	137,034	2,153,741
2013/14	2,353,787	157,689	2,196,098
2014/15	2,428,411	180,118	2,248,293
2015/16	2,498,714	203,251	2,295,463
CAGR	2.7%	14.5%	1.9%

Planning Load for the Maine Division C&I LLF Customer Segment includes the sum of C&I LLF firm sales demand plus 50% of the C&I LLF transportation demand subject to capacity assignment rules in the winter, and only includes C&I LLF firm sales demand in the summer.

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

The C&I HLF Customer Segment[28] is the Maine Division's fourth largest Customer Segment in terms of number of customers, but the second largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the C&I HLF Customer Segment represented approximately 8% of Maine Division total customers and approximately 31% of Maine Division total actual demand. Over the same time period, the number of C&I HLF customers decreased by approximately 3.7% per year and weather normalized total C&I HLF demand decreased by approximately 0.6% per year.

(1) C&I HLF Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as employment levels (i.e., total employment or manufacturing employment) or gross metropolitan product should be considered when developing a C&I HLF customer model. In the final regression equation that was selected to predict the number of C&I HLF customers, manufacturing employment lagged by four quarters, and several time-specific dummy variables were statistically significant. As shown below in Table III-17, the number of C&I HLF customers is expected to grow at an annual rate of 0.5% over the forecast period.

[28] The C&I HLF Customer Segment includes both firm sales (G-50, G-51, and G-52) and firm transportation (T-50, T-51, and T-52) customers, unless noted otherwise.

Table III-17: C&I HLF Customer Model Forecast – Maine Division

Split Year	Average Customer Forecast
2011/12	1,829
2012/13	1,838
2013/14	1,852
2014/15	1,859
2015/16	1,863
CAGR	0.5%

(2) C&I HLF Use Per Customer Model Results – Maine Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, employment levels (i.e., total employment or manufacturing employment), or gross metropolitan product should be considered when developing a C&I HLF use per customer model. In the final regression equation that was selected to predict C&I HLF use per customer, billing cycle EDD, C&I HLF natural gas price, time-specific dummy variables, quarterly dummy variables and interactions were statistically significant. Over the forecast period, the use per customer for the C&I HLF Customer Segment is expected to increase marginally by 0.1% per year as shown in Table III-18 below.

Table III-18: C&I HLF Use Per Customer Model Forecast – Maine Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	1,280.4
2012/13	1,269.6
2013/14	1,266.7
2014/15	1,277.1
2015/16	1,284.5
CAGR	0.1%

(3) C&I HLF Demand Results – Maine Division

The C&I HLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF customers for each quarter by the forecasted C&I HLF use per customer for that quarter. As shown in Table III-19 below, C&I HLF demand is expected to increase by 0.5% per year over the forecast period.

Table III-19: C&I HLF Demand Forecast– Maine Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	2,341,644
2012/13	2,333,970
2013/14	2,346,243
2014/15	2,374,106
2015/16	2,393,487
CAGR	0.5%

The forecasted 0.5% annual growth in C&I HLF demand is the net effect of the forecasted 0.5% annual growth in customers and the forecasted 0.1% increase in use per customer. The primary driver of this annual demand growth is the forecasted growth in manufacturing employment.

(4) C&I HLF Planning Load – Maine Division

As discussed previously, Maine Division C&I Planning Load includes C&I firm sales demand and 50% of transportation load that is subject to the capacity assignment rules in the winter, and excludes all capacity exempt and non-capacity assigned transportation load. In the summer, C&I Planning Load for the Maine Division is comprised of only C&I firm sales demand. The Planning Load associated with the C&I HLF Customer Segment for the Maine Division was determined by: (1) estimating the portions of total C&I HLF firm demand that are (a) sales and (b) transportation; and (2) estimating the portions of C&I HLF firm transportation demand that are (a) subject to capacity assignment rules and (b) capacity exempt.

(a) C&I HLF Firm Sales and C&I HLF Firm Transportation Demand – Maine Division

Over the historical period of 2005/06 through 2010/11, C&I HLF firm transportation demand has been growing faster than C&I HLF firm sales demand. In 2010/11, approximately 17% of the total C&I HLF demand was firm sales demand, and the remaining 83% was firm transportation demand. The forecast demand for C&I HLF firm transportation was developed according to the following process. First, a regression equation was developed to predict the percentage of C&I HLF firm transportation demand of total HLF sales and transportation demand based on billing cycle EDD and interactions with quarters, a quarterly trend, and several time-specific dummy variables. Second, the C&I HLF firm transportation demand forecast was calculated by multiplying the forecasted firm transportation percentages for each quarter by the forecasted total C&I HLF demand for that quarter. Finally, the forecast of C&I HLF firm sales demand was developed by subtracting the forecast of C&I HLF transportation demand from the forecast of total C&I HLF demand forecast. As discussed previously, the C&I HLF combined firm sales and firm transportation demand is expected to increase by 0.5% per year over the forecast period. C&I HLF firm transportation demand is expected to increase by 1.2% per year, while C&I HLF firm sales demand is expected to decline by 2.8% per year, as shown in Table III-20 below.

Table III-20: C&I HLF Sales and Transportation Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth)		
	Total C&I HLF	Firm Transportation	Firm Sales
2011/12	2,341,644	1,958,001	383,642
2012/13	2,333,970	1,963,829	370,141
2013/14	2,346,243	1,986,469	359,774
2014/15	2,374,106	2,022,483	351,623
2015/16	2,393,487	2,051,510	341,977
CAGR	0.5%	1.2%	-2.8%

(b) C&I HLF Transportation Subject to Capacity Assignment Rules and Capacity Exempt Transportation Demand – Maine Division

In 2010/11, approximately 76% of the C&I HLF firm transportation demand was subject to capacity assignment rules and the remaining 24% was capacity exempt. The forecast demand for C&I HLF capacity exempt transportation was developed according to the following process. First, a model was developed to forecast capacity exempt demand as a percentage of total C&I HLF firm transportation demand based on the natural log of a quarterly trend, quarterly dummy variables and billing cycle EDDs. Second, the C&I HLF capacity exempt transportation demand forecast was calculated by multiplying the forecasted capacity exempt percentages for each quarter by the forecasted C&I HLF firm transportation demand for that quarter. Finally, the forecast of C&I HLF demand that is subject to capacity assignment rules was developed by subtracting the forecast of C&I HLF capacity exempt transportation demand from the forecast of total C&I HLF firm transportation. As discussed previously, the total C&I HLF firm transportation demand is expected to increase by 1.2% per year over the forecast period. C&I HLF demand that is subject to capacity assignment rules is expected to increase by 0.4% per year, while C&I HLF capacity exempt transportation demand is expected to increase by 3.2% per year as shown in Table III-21 below.

Table III-21: C&I HLF Transportation Subject to Capacity Assignment Rules & Capacity Exempt Transportation Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth)		
	Firm Transportation	Capacity Exempt	Subject to Capacity Assignment Rules
2011/12	1,958,001	500,376	1,457,625
2012/13	1,963,829	515,691	1,448,138
2013/14	1,986,469	532,869	1,453,600
2014/15	2,022,483	552,080	1,470,403
2015/16	2,051,510	568,329	1,483,180
CAGR	1.2%	3.2%	0.4%

Planning Load for the Maine Division C&I HLF Customer Segment includes the sum of C&I HLF firm sales demand plus 50% of the C&I HLF transportation demand subject to capacity assignment rules in the winter, and only includes C&I HLF firm sales demand in the summer.

e) Special Contracts – Maine Division

The Special Contract Customer Segment, in aggregate, is the Maine Division's third largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the Special Contract Customer Segment represented approximately 14% of Maine Division total actual demand. Over the same time period, weather normalized total Special Contract demand increased by approximately 7.3% per year.[29]

The Special Contract demand forecast was developed by summing the results of individual demand forecasts for each Special Contract customer. Variables such as weather, natural gas prices, employment levels (i.e., total employment or manufacturing employment), or gross state product were considered in developing the individual Special Contract demand models. Detailed statistical summaries, including (a) the results of the statistical tests that were performed, (b) historical actual data, (c) historical fitted values, and (d) forecasted values are provided in Appendix III-6. Over the forecast period, Special Contract demand, in aggregate, is expected remain relatively constant as shown in Table III-22 below.

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29 The historical Special Contract demand growth rate is affected by several changes in the historical demand of individual Special Contract customers. The Company's Business Services Department does not expect any similar large changes in Special Contract demand during the forecast period.

Table III-22: Special Contract Demand Forecast – Maine Division

Split Year	Normal Year Forecast (Dth)
2011/12	1,210,233
2012/13	1,208,293
2013/14	1,207,870
2014/15	1,209,574
2015/16	1,210,802
CAGR	0.0%

All of the Maine Division Special Contract customers are subject to capacity assignment rules; therefore, 50% of the Special Contract winter demand was included in the Maine Division's Planning Load.

f) Summary of Customer Segment Demand Forecast Results – Maine Division

In aggregate, the Maine Division Customer Segment demand is projected to grow at a rate of 1.0% per year over the forecast period. Sales plus capacity assigned demand is projected to grow at 0.3% per year, and capacity exempt demand is projected to grow at 1.8% per year, as shown in Table III-23 below.

Table III-23: Base Case Normal Year Customer Segment Demand Forecast Results (Dth)[30] – Maine Division

Split Year	Total Customer Segment Demand	Planning Load (Sales Plus Capacity Assigned Demand[31])	Capacity Exempt Plus Non-Capacity Assigned Demand[32]
2011/12	8,602,820	4,562,572	4,040,248
2012/13	8,628,545	4,543,623	4,084,922
2013/14	8,710,099	4,553,728	4,156,371
2014/15	8,837,309	4,588,542	4,248,767
2015/16	8,946,352	4,615,621	4,330,731
CAGR (11/12-15/16)	1.0%	0.3%	1.8%

4. Customer Segment Model Results – New Hampshire Division

This section summarizes the results of each Customer Segment model for Northern's New Hampshire Division. Detailed statistical summaries including (a) the results of the statistical tests that were performed for each Customer Segment model, (b) historical actual data, (c) historical fitted values derived from each model, and (d) forecasted values derived from each model are provided in Appendix III-7. In addition, Appendix III-7 contains summary results for each Customer Segment for the New Hampshire Division.

a) Residential Heating Customer Segment Forecast – New Hampshire Division

Residential Heating is the New Hampshire Division's largest Customer Segment in terms of number of customers, but is the third largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11,[33] the Residential Heating Customer Segment represented approximately 71% of New Hampshire Division total customers and approximately 23% of New Hampshire Division total actual demand. Over the same time period, the number of Residential Heating

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30 Demand forecast results do not include incremental savings from energy efficiency programs or incremental growth from marketing activities.

31 Sales plus capacity assigned demand includes 50% of transportation demand that is subject to capacity assignment rules in the winter and 0% of transportation demand in the summer.

32 Capacity exempt plus non-capacity assigned demand includes all transportation demand that is not subject to the capacity assignment rules year-round, plus 50% of transportation demand that is subject to capacity assignment rules in the winter and 100% of transportation demand that is subject to capacity assignment rules in the summer.

33 For the purpose of identifying historical usage trends, the 6-year period from 2005/06 to 2010/11 was used. Please note that 2010/11 includes actual data through March 2011 and forecast data for the remainder of the split year.

customers increased by approximately 1.4%[34] per year, while weather normalized total Residential Heating demand increased by approximately 0.6% per year.[35] Currently, Residential Heating customers are not eligible for transportation service, and as a result no Residential Heating customers are subject to the New Hampshire conditions of capacity assignment; therefore, all Residential Heating demand is included in Planning Load.

(1) Residential Heating Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as the number of people living in the service territory (i.e., households, population, housing stock, or cumulative housing starts), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Heating customer model. In the final regression equation that was selected to predict the number of Residential Heating customers, housing stock, quarterly dummy variables, and several time-specific dummy variables, and interactions were statistically significant. Over the forecast period, the number of Residential Heating customers is expected to grow at an annual rate of 1.9% as shown in Table III-24 below.

Table III-24: Residential Heating Customer Model Forecast[36] – New Hampshire Division

Split Year	Average Customer Forecast
2011/12	20,715
2012/13	20,991
2013/14	21,384
2014/15	21,835
2015/16	22,309
CAGR	1.9%

(2) Residential Heating Use Per Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, the average number of people per house (i.e., household size), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Heating use per customer model. In the final regression equation that was selected to predict

[34] Some historical growth rates are affected by shifts that occurred in the historical data.

[35] Growth rates throughout this report are calculated as compound annual growth rates ("CAGR"), unless noted otherwise. CAGR = ((last value / first value)^(1/# of periods between last and first values)) - 1

[36] All number of customer forecasts are presented in split years that correspond to calendar quarters (i.e., October through September).

Residential Heating use per customer, billing cycle EDD, Residential Heating natural gas price, quarterly dummy variables, interactions, and time-specific dummy variables were statistically significant. Over the forecast period, the use per customer for the Residential Heating Customer Segment is expected to increase by 0.3% per year as shown in Table III-25 below.

Table III-25: Residential Heating Use Per Customer Model Forecast[37] – New Hampshire Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	79.7
2012/13	79.4
2013/14	79.4
2014/15	80.0
2015/16	80.5
CAGR	0.3%

(3) Residential Heating Demand Results – New Hampshire Division

The Residential Heating demand forecast was calculated by multiplying the forecasted number of Residential Heating customers for each quarter by the forecasted Residential Heating use per customer for that quarter. Over the forecast period, Residential Heating demand is expected to increase by approximately 2.1% per year as shown in Table III-26 below.

[37] All use per customer forecasts are presented in split years that correspond to calendar quarters (i.e., October through September).

Table III-26: Residential Heating Demand Forecast[38,39] – New Hampshire Division

Split Year	Normal Year Forecast (Dth)
2011/12	1,650,615
2012/13	1,665,749
2013/14	1,697,663
2014/15	1,747,363
2015/16	1,796,439
CAGR	2.1%

The forecasted annual growth rate for Residential Heating demand of 2.1% is the net effect of the forecasted 1.9% annual growth in customers and the forecasted 0.3% annual increase in use per customer. The primary driver of this annual demand growth rate is the forecasted growth in housing stock.

b) Residential Non-Heating Customer Segment Forecast – New Hampshire Division

Residential Non-Heating is the New Hampshire Division's third largest Customer Segment in terms of number of customers, but the smallest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the Residential Non-Heating Customer Segment represented approximately 6% of the New Hampshire Division total customers and less than 1% of the New Hampshire Division total actual demand. Over the same time period, the number of Residential Non-Heating customers decreased by approximately 2.4% per year, but weather normalized total Residential Non-Heating demand increased by approximately 2.9% per year. Currently, no Residential Non-Heating customers are using transportation service, and as a result no Residential Non-Heating customers are subject to the New Hampshire conditions of capacity assignment; therefore, all Residential Non-Heating demand is included in Planning Load.

38 All Customer Segment demand forecast results are before adjustments for energy efficiency savings, marketing, losses and unbilled sales.

39 All demand forecast split years are November through October. To develop a split year forecast for the traditional gas year (i.e., November through October), the fourth quarter results were allocated to the appropriate gas year (e.g., October of 2012 was allocated to the 2011/12 split year, while November and December of 2012 were allocated to the 2012/13 split year).

(1) Residential Non-Heating Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as the number of people living in the service territory (i.e., households, population, housing stock, or cumulative housing starts), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Non-Heating customer model. In the final regression equation that was selected to predict the number of Residential Non-Heating customers, a quarterly trend variable, quarterly dummy variables, and several time-specific dummy variables and interactions were statistically significant. As shown below in Table III-27, the number of Residential Non-Heating customers is projected to decline at an annual rate of 3.2% over the forecast period.

Table III-27: Residential Non-Heating Customer Model Forecast – New Hampshire Division

Split Year	Average Customer Forecast
2011/12	1,570
2012/13	1,522
2013/14	1,475
2014/15	1,427
2015/16	1,380
CAGR	-3.2%

(2) Residential Non-Heating Use Per Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, the average number of people per house (i.e., household size), and income levels (i.e., household income or income per capita) should be considered when developing a Residential Non-Heating use per customer model. In the final regression equation that was selected to predict Residential Non-Heating use per customer, billing cycle EDD, Residential Non-Heating natural gas price, quarterly dummy variables, and time-specific dummy variables and interactions were statistically significant. Over the forecast period, the use per customer for the Residential Non-Heating Customer Segment is expected to increase by approximately 0.2% per year as shown in Table III-28 below.

Table III-28: Residential Non-Heating Use Per Customer Model Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	21.6
2012/13	21.3
2013/14	21.2
2014/15	21.6
2015/16	21.8
CAGR	0.2%

(3) Residential Non-Heating Demand Results – New Hampshire Division

The Residential Non-Heating demand forecast was calculated by multiplying the forecasted number of Residential Non-Heating customers for each quarter by the forecasted Residential Non-Heating use per customer for that quarter. As shown in Table III-29 below, Residential Non-Heating demand is expected to decline by approximately 3.0% per year over the forecast period.

Table III-29: Residential Non-Heating Demand Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth)
2011/12	33,989
2012/13	32,433
2013/14	31,317
2014/15	30,789
2015/16	30,080
CAGR	-3.0%

The forecasted 3.0% annual decrease in Residential Non-Heating demand of is the net effect of the forecasted 3.2% annual decrease in the customer count and the forecasted 0.2% annual increase in use per customer. Thus, the primary driver of the decrease in Residential Non-Heating demand is the negative trend in the number of Residential Non-Heating customers.

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

The C&I LLF Customer Segment[40] is the New Hampshire Division's second largest Customer Segment in terms of number of customers and the largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the C&I LLF Customer Segment represented approximately 18% of New Hampshire Division total customers and approximately 34% of New Hampshire Division total actual demand. Over the same time period, the number of C&I LLF customers increased by approximately 1.1% per year and weather normalized total C&I LLF demand increased by approximately 1.8% per year.

(1) C&I LLF Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as employment levels (i.e., total employment, non-manufacturing employment, or service employment), retail sales, or gross metropolitan product should be considered when developing a C&I LLF customer model. In the final regression equation that was selected to predict the number of C&I LLF customers, non-manufacturing employment, quarterly dummy variables, and several time-specific dummy variables and interactions were statistically significant. As shown below in Table III-30, the number of C&I LLF customers is expected to grow at an annual rate of 1.1% over the forecast period.

Table III-30: C&I LLF Customer Model Forecast – New Hampshire Division

Split Year	Average Customer Forecast
2011/12	5,098
2012/13	5,146
2013/14	5,208
2014/15	5,265
2015/16	5,318
CAGR	1.1%

(2) C&I LLF Use Per Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, employment levels (i.e., total employment, non-manufacturing employment, or

[40] The C&I LLF Customer Segment includes both firm sales (G-40, G-41, and G-42) and firm transportation (T-40, T-41, and T-42) customers, unless noted otherwise.

service employment), retail sales, or gross metropolitan product should be considered when developing a C&I LLF use per customer model. In the final regression equation that was selected to predict C&I LLF use per customer, billing cycle EDD, C&I LLF natural gas price, quarterly dummy variables, and time-specific dummy variables were statistically significant. Over the forecast period, the use per customer for the C&I LLF Customer Segment is expected to remain relatively constant as shown in Table III-31 below.

Table III-31: C&I LLF Use Per Customer Model Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	496.6
2012/13	493.2
2013/14	492.4
2014/15	495.2
2015/16	497.3
CAGR	0.0%

(3) C&I LLF Demand Results – New Hampshire Division

The C&I LLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF customers for each quarter by the forecasted C&I LLF use per customer for that quarter. As shown in Table III-32 below, C&I LLF demand is expected to grow by 1.1% per year over the forecast period.

Table III-32: C&I LLF Demand Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth)
2011/12	2,531,573
2012/13	2,537,757
2013/14	2,564,223
2014/15	2,607,270
2015/16	2,644,845
CAGR	1.1%

The forecasted 1.1% annual growth rate for C&I LLF demand is the net effect of the forecasted 1.1% annual growth in customers and the forecasted 0.0% annual growth in use per customer. The primary driver of this annual demand growth is the forecasted growth in non-manufacturing employment.

(4) C&I LLF Planning Load – New Hampshire Division

Northern began offering unbundled sales and transportation services to C&I customers in its New Hampshire Division in the mid-1990s. Subsequently, Northern participated in a proceeding initiated by the New Hampshire Commission to adopt permanent rules associated with unbundled service offerings (Docket DE 98-124). Northern's distribution service terms and conditions that resulted from that proceeding provided for the mandatory assignment of capacity beginning in 1999. Customers who elected transportation service prior to March 14, 2000, or new customers who never took sales service from the Company, are exempted from the capacity assignment requirement.[41,42] As a result of this capacity assignment process, Northern must continue to provide capacity for its New Hampshire capacity assigned transportation customers.

C&I Planning Load for the New Hampshire Division includes (1) the C&I firm sales demand, and (2) the capacity assigned transportation load; capacity exempt transportation load is not included in the New Hampshire Division C&I Planning Load. The Planning Load associated with the C&I LLF Customer Segment for the New Hampshire Division was determined by estimating the portions of total C&I LLF firm demand that are (1) sales and capacity assigned transportation demand, and (2) C&I LLF capacity exempt transportation demand.

(a) C&I LLF Firm Sales plus Capacity Assigned Transportation and Capacity Exempt Transportation Demand – New Hampshire Division

In 2010/11, approximately 87% of the C&I LLF Customer Segment demand was firm sales plus capacity assigned transportation demand and the remaining 13% was capacity exempt transportation load. The forecast demand for C&I LLF capacity exempt transportation was developed according to the following process. First, a model was developed to forecast capacity exempt demand as a percentage of C&I LLF demand based on billing cycle EDDs and a quarterly dummy variable. Second, the C&I LLF capacity exempt transportation demand forecast was calculated by multiplying the forecasted capacity exempt percentages for each quarter by the forecasted C&I LLF demand for that quarter. Finally, the forecast of C&I LLF firm sales plus capacity assigned transportation demand was developed by subtracting the forecast of capacity exempt transportation demand from the forecast of C&I LLF demand. As discussed previously, the C&I LLF demand is expected to increase by 1.1% per year over the forecast period. C&I LLF firm sales plus capacity assigned transportation demand is expected to grow at

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41 For a transportation customer that requests to migrate to sales service, Northern not obligated to provide firm sales service above the level of the customer's assigned capacity unless Northern has sufficient capacity available to do so.

42 With respect to reliability, Northern has the ability to recall capacity assigned to competitive suppliers in the event that they fail to deliver required volumes on behalf of their transporting customers.

an annual rate of 1.1%, while C&I LLF capacity exempt transportation demand is also expected to increase by 1.1% per year, as shown in Table III-33 below.

Table III-33: C&I LLF Firm Sales plus Capacity Assigned Transportation and Capacity Exempt Transportation Demand Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth)		
	Total C&I LLF	Capacity Exempt Transport	Sales plus Capacity Assigned Transport
2011/12	2,531,573	371,157	2,160,416
2012/13	2,537,757	371,624	2,166,133
2013/14	2,564,223	375,581	2,188,642
2014/15	2,607,270	382,456	2,224,814
2015/16	2,644,845	388,483	2,256,362
CAGR	1.1%	1.1%	1.1%

Planning Load for the New Hampshire Division C&I LLF Customer Segment includes the sum of C&I LLF firm sales plus capacity assigned transportation demand; the capacity exempt transportation demand is not included.

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

The C&I HLF Customer Segment[43] is the New Hampshire Division's fourth largest Customer Segment in terms of number of customers, but the second largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the C&I HLF Customer Segment represented approximately 5% of the New Hampshire Division total customers and approximately 27% of the New Hampshire Division total actual demand. Over the same time period, the number of C&I HLF customers has decreased at an annual rate of 0.2% and weather normalized total C&I HLF demand has grown at an annual rate of 3.4%.

(1) C&I HLF Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as employment levels (i.e., total employment or manufacturing employment) or gross metropolitan product should be considered when developing a C&I HLF customer model. In the final regression equation that was selected to predict the number of C&I HLF customers, manufacturing employment lagged by four quarters, quarterly dummy variables, and several time-specific dummy variables were

[43] The C&I HLF Customer Segment includes both firm sales (G-50, G-51, and G-52) and firm transportation (T-50, T-51, and T-52) customers, unless noted otherwise.

statistically significant. As shown below in Table III-34, the number of C&I HLF customers is expected to grow at an annual rate of 0.2% over the forecast period.

Table III-34: C&I HLF Customer Model Forecast – New Hampshire Division

Split Year	Average Customer Forecast
2011/12	1,236
2012/13	1,240
2013/14	1,243
2014/15	1,245
2015/16	1,247
CAGR	0.2%

(2) C&I HLF Use Per Customer Model Results – New Hampshire Division

Based on economic theory and standard utility forecasting practice, variables such as weather, natural gas prices, employment levels (i.e., total employment or manufacturing employment), or gross metropolitan product should be considered when developing a C&I HLF use per customer model. In the final regression equation that was selected to predict C&I HLF use per customer, billing cycle EDD, C&I HLF natural gas price, manufacturing employment, and time-specific dummy variables and interactions were statistically significant. Over the forecast period, the use per customer for the C&I HLF Customer Segment is expected to increase by 1.3% per year as shown in Table III-35 below.

Table III-35: C&I HLF Use Per Customer Model Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth/Customer)
2011/12	1,537.0
2012/13	1,544.0
2013/14	1,557.7
2014/15	1,598.7
2015/16	1,620.0
CAGR	1.3%

(3) C&I HLF Demand Results – New Hampshire Division

The C&I HLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF customers for each quarter by the forecasted C&I HLF use per customer for that quarter. As shown in Table III-36 below, C&I HLF demand is expected to grow at an annual rate of approximately 1.6% per year over the forecast period.

Table III-36: C&I HLF Demand Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth)
2011/12	1,899,163
2012/13	1,914,767
2013/14	1,936,753
2014/15	1,990,791
2015/16	2,020,584
CAGR	1.6%

The forecasted 1.6% annual growth rate for C&I HLF demand is the net effect of the forecasted 0.2% annual increase in customers and the forecasted 1.3% increase in use per customer. The primary driver of the growth in C&I HLF demand is the forecasted growth in manufacturing employment over the forecast period.

(4) C&I HLF Planning Load – New Hampshire Division

As discussed previously, New Hampshire Division C&I Planning Load includes C&I firm sales demand and capacity assigned transportation load, and excludes all capacity exempt transportation load.

(a) C&I HLF Firm Sales plus Capacity Assigned Transportation and Capacity Exempt Transportation Demand – New Hampshire Division

In 2010/11, approximately 42% of the C&I HLF Customer Segment demand was firm sales plus capacity assigned transportation demand, and the remaining 58% was capacity exempt transportation demand. The forecast demand for C&I HLF capacity exempt transportation was developed according to the following process. First, a model was developed to forecast capacity exempt demand as a percentage of C&I HLF demand based on the natural log of a quarterly trend and quarterly dummy variables. Second, the C&I HLF capacity exempt transportation demand forecast was calculated by multiplying the forecasted capacity exempt percentages for each quarter by the forecasted C&I HLF demand for that quarter. Finally, the forecast of C&I HLF firm sales plus capacity assigned transportation demand was developed by subtracting the forecast C&I HLF capacity exempt transportation demand from the forecast total C&I HLF demand. As discussed previously, the total C&I HLF demand is expected to increase by 1.6% per year over the forecast period. C&I HLF firm sales plus capacity assigned transportation demand is expected to increase at an annual rate of 0.4%, while C&I HLF capacity exempt transportation demand is expected to increase by 2.4% per year as shown in Table III-37 below.

Table III-37: C&I HLF Firm Sales plus Capacity Assigned Transportation and Capacity Exempt Transportation Demand Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth)		
	Total C&I HLF	Capacity Exempt Transport	Sales plus Capacity Assigned Transport
2011/12	1,899,163	1,107,867	791,296
2012/13	1,914,767	1,129,102	785,665
2013/14	1,936,753	1,151,612	785,142
2014/15	1,990,791	1,191,761	799,030
2015/16	2,020,584	1,216,721	803,863
CAGR	1.6%	2.4%	0.4%

Planning Load for the New Hampshire Division C&I HLF Customer Segment includes the sum of C&I HLF firm sales plus capacity assigned transportation demand; the capacity exempt transportation demand is not included.

e) Special Contracts – New Hampshire Division

The Special Contract Customer Segment, in aggregate, is the New Hampshire Division's fourth largest Customer Segment in terms of demand. For the historical period of 2005/06 through 2010/11, the Special Contract Customer Segment represented approximately 16% of the New Hampshire Division's total actual demand. Over the same time period, weather normalized total Special Contract demand decreased by approximately 2.2% per year.[44] The Special Contract demand forecast was developed by summing the results of the individual demand forecasts for each Special Contract customer. Variables such as weather, natural gas prices, employment levels (i.e., total employment or manufacturing employment), housing starts, or gross state product were considered in developing the individual Special Contract demand models. Detailed statistical summaries, including (a) the results of the statistical tests that were performed, (b) historical actual data, (c) historical fitted values, and (d)

[44] The historical Special Contract demand decline is affected by several changes in the historical demand of individual Special Contract customers. The Company's Business Services Department does not expect any similar, large changes in Special Contract demand during the forecast period.

forecasted values are provided in Appendix III-7. Over the forecast period, Special Contract demand, in aggregate, is expected to grow at an annual rate of 1.5% as shown in Table III-38 below.

Table III-38: Special Contract Demand Forecast – New Hampshire Division

Split Year	Normal Year Forecast (Dth)
2011/12	1,030,002
2012/13	1,049,474
2013/14	1,074,327
2014/15	1,087,362
2015/16	1,092,035
CAGR	1.5%

New Hampshire Division Special Contract customers that are capacity assigned were included in the New Hampshire Division's Planning Load; New Hampshire Division Special Contract customers that are capacity exempt were excluded from the New Hampshire Division's Planning Load.

f) Summary of Customer Segment Demand Forecast Results – New Hampshire Division

In aggregate, the New Hampshire Division Customer Segment demand is projected to grow at a rate of 1.5% per year over the forecast period. Sales plus capacity assigned demand is projected to grow at 1.2% per year, and capacity exempt demand is projected to grow at 2.3% per year, as shown in Table III-39 below.

Table III-39: Base Case Normal Year Customer Segment Demand Forecast Results (Dth)[45] – New Hampshire Division

Split Year	Total Customer Segment Demand	Sales Plus Capacity Assigned Demand	Capacity Exempt Demand
2011/12	7,145,342	5,160,169	1,985,173
2012/13	7,200,179	5,173,832	2,026,347
2013/14	7,304,282	5,226,615	2,077,667
2014/15	7,463,575	5,325,849	2,137,726
2015/16	7,583,983	5,410,596	2,173,387
CAGR (11/12-15/16)	1.5%	1.2%	2.3%

D. Normal Year Firm Planning Load Forecast

1. Introduction

As discussed previously, the objective of the demand forecast is to develop a forecast of firm Planning Load. The Normal Year firm Planning Load forecast is calculated by summing (1) the Normal Year sales plus capacity assigned forecasts for the five Customer Segments, (2) projected incremental energy efficiency savings, represented as a negative number, (3) projected incremental demand from marketing efforts, (4) Company Use, and (5) losses and unbilled sales.

2. Energy Efficiency Savings

An out-of-model adjustment was made to the demand forecast for savings associated with the Company's existing energy efficiency programs. The Company prepared forecasted incremental energy savings associated with approved residential, commercial and industrial energy efficiency programs[46] for the forecast period for both Divisions. See Section V-D for a detailed discussion of these energy efficiency programs and the projections of actual and projected energy savings. Table III-40 below provides the projected cumulative incremental energy efficiency program savings for each year of the forecast period that are deducted from the Customer Segment demand forecast.[47]

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45 Demand forecast results do not include incremental savings from energy efficiency programs or incremental growth from marketing efforts.

46 Energy efficiency programs refer to energy efficiency activity funded through charges to Northern's natural gas customers. Forecasted energy efficiency savings do not include savings associated with any new or expanded programs.

47 These projected cumulative energy efficiency savings were deducted from the normal year and design year scenarios.

Table III-40: Forecasted Cumulative Energy Efficiency Savings by Division (Dth)

Split Year	Maine Division	New Hampshire Division
2011/12	-15,628	-27,425
2012/13	-30,668	-46,161
2013/14	-45,708	-64,897
2014/15	-60,748	-83,633
2015/16	-75,700	-102,369

The projected energy efficiency savings in 2011/12 are roughly 0.2% of annual sales in Maine, and 0.5% of annual sales in New Hampshire. These percentages increase by 2015/16 to approximately 1.2% in Maine and 1.7% in New Hampshire. For IRP planning purposes these values were allocated to sales, capacity assigned, and capacity exempt transportation in proportion to the projected demand by these categories in the forecast period.

3. Marketing Adjustment

An out-of-model adjustment was made for projected growth associated with the Company's marketing efforts. The Company prepared a forecast of incremental customer growth to capture growing demand for natural gas associated with factors not explicitly captured by the statistical models, such as (a) the increased price competitiveness of gas above what is reflected in the historical data that is the basis for the Customer Segment models, (b) growing awareness of the environmental advantages of natural gas compared to heating oil and electric heat and (c) the Company's increased marketing activities intended to capture the benefits of these positive marketing factors. The projected incremental demand associated with the marketing factors is added to the Customer Segment demand forecast is shown in Table III-41 below for each year of the forecast period by Division.

Table III-41: Marketing Adjustment - Forecasted Incremental Demand by Division (Dth)

Split Year	Maine Division	New Hampshire Division
2011/12	134,985	93,905
2012/13	255,749	180,576
2013/14	376,557	269,758
2014/15	500,101	364,806
2015/16	623,567	461,333

The projected marketing adjustment in 2011/12 is equal to approximately 1.7% of annual sales in Maine and 1.3% of annual sales in New Hampshire. The adjustments increase by 2015/16 to approximately 7.7% in Maine and 6.3% in New Hampshire. These values were allocated to sales, capacity assigned, and capacity exempt transportation in proportion to the projected demand by these categories in the forecast period.

4. Company Use

Company Use includes natural gas used to heat Company buildings, to run the Lewiston LNG plant, and to pre-heat gas[48]. In the regression equations that were selected to predict Company Use for the Maine and New Hampshire Divisions, billing cycle EDD, quarterly dummy variables, and time-specific dummy variables and interactions were statistically significant. Over the forecast period, Company Use for both the Maine and New Hampshire Divisions was projected to remain constant as shown in Table III-42 below.

Table III-42: Company Use by Division

Split Year	Normal Year Forecast (Dth)	
	Maine Division	New Hampshire Division
2011/12	7,141	631
2012/13	7,143	631
2013/14	7,143	631
2014/15	7,143	631
2015/16	7,143	631
CAGR	0.0%	0.0%

5. Losses and Unbilled Sales

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 on a calendar period basis, the Customer Segment and Company Use forecasts were adjusted for losses and unbilled sales. Seven and a half 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") was compiled by season to develop forecasts of percentage losses and unbilled sales by Division. Table III-43 below shows the losses and unbilled sales percentage

48 In some circumstances, gas is "pre heated" to prevent frost heaves above large mains that are located a short distance downstream from a regulator station.

calculations for the Maine Division, and Table III-44 below shows the losses and unbilled sales percentage calculations for the New Hampshire Division.[49]

Table III-43: Losses and Unbilled Sales – Maine Division

Seasonal Totals	Total System Throughput (includes IT and SPC) (Dth)	Gas Accounted For (Gas Used by All Customers plus Company Use) (Dth)	Gas Unaccounted For (Dth)	% Unaccounted For (includes Losses and Unbilled Sales)
2003/04 Winter	4,658,553	4,357,118	301,435	6.92%
2003/04 Summer	3,082,487	3,162,492	-80,005	-2.53%
2004/05 Winter	4,536,646	4,227,140	309,506	7.32%
2004/05 Summer	3,001,813	3,078,846	-77,034	-2.50%
2005/06 Winter	4,111,964	3,883,347	228,617	5.89%
2005/06 Summer	2,974,370	3,047,543	-73,172	-2.40%
2006/07 Winter	4,694,297	4,434,209	260,087	5.87%
2006/07 Summer	3,102,666	3,206,679	-104,013	-3.24%
2007/08 Winter	5,327,058	4,953,908	373,150	7.53%
2007/08 Summer	3,083,013	3,220,577	-137,564	-4.27%
2008/09 Winter	5,503,111	5,195,714	307,397	5.92%
2008/09 Summer	3,079,241	3,047,229	32,012	1.05%
2009/10 Winter	4,976,433	4,763,983	212,450	4.46%
2009/10 Summer	2,868,696	2,886,685	-17,989	-0.62%
2010/11 Winter	5,695,806	5,410,525	285,281	5.27%
Winter Average				6.15%
Summer Average				-2.07%

49 The Company prepared calculations of historical losses and unbilled sales as a percentage of billed usage; forecasted losses and unbilled sales are calculated as: (Customer Segment demand – energy efficiency savings + marketing adjustment + Company Use) * % losses and unbilled sales. The projected losses and unbilled sales by quarter are added to the projected quarterly Customer Segment and Company Use demand forecast results (adjusted for energy efficiency savings and marketing adjustment) to produce the calendar period Planning Load.

Table III-44: Losses and Unbilled Sales – New Hampshire Division

Seasonal Totals	Total System Throughput (includes IT and SPC) (Dth)	Gas Accounted For (Gas Used by All Customers plus Company Use) (Dth)	Gas Unaccounted For (Dth)	% Unaccounted For (includes Losses and Unbilled Sales)
2003/04 Winter	4,534,738	4,207,412	327,326	7.78%
2003/04 Summer	2,495,051	2,666,446	-171,395	-6.43%
2004/05 Winter	4,423,202	4,160,468	262,734	6.32%
2004/05 Summer	2,489,976	2,665,806	-175,830	-6.60%
2005/06 Winter	4,015,346	3,814,415	200,931	5.27%
2005/06 Summer	2,592,287	2,694,552	-102,264	-3.80%
2006/07 Winter	4,405,172	4,089,207	315,965	7.73%
2006/07 Summer	2,853,992	3,044,061	-190,068	-6.24%
2007/08 Winter	4,662,166	4,326,468	335,698	7.76%
2007/08 Summer	2,686,926	2,892,780	-205,854	-7.12%
2008/09 Winter	4,541,736	4,322,012	219,725	5.08%
2008/09 Summer	2,552,796	2,692,587	-139,791	-5.19%
2009/10 Winter	4,259,522	4,112,662	146,861	3.57%
2009/10 Summer	2,396,770	2,505,999	-109,229	-4.36%
2010/11 Winter	4,635,015	4,404,505	230,510	5.23%
Winter Average				6.09%
Summer Average				-5.68%

6. Firm Planning Load Forecast

Planning Load (i.e., total sales and capacity assigned transportation demand adjusted for energy efficiency savings, marketing adjustment, Company Use, and losses and unbilled sales) is projected to increase at an average annual rate of 1.5% over the forecast period in the Maine Division and increase at an annual rate of 2.1% over the forecast period in the New Hampshire Division, under normal conditions. Planning Load results are summarized in Table III-45 – Maine Division and Table III-46 – New Hampshire Division below.

Table III-45: Base Case Normal Year Planning Load Results (Dth) – Maine Division

Split Year	Residential	C&I Sales plus Capacity Assigned[50]	Energy Efficiency	Marketing Adjustment	Company Use	Losses and Unbilled Sales	Planning Load
2011/12	1,157,708	3,404,864	-10,956	75,441	7,141	199,451	4,833,649
2012/13	1,164,836	3,378,787	-21,780	146,215	7,143	201,794	4,876,995
2013/14	1,181,967	3,371,761	-32,457	215,714	7,143	205,053	4,949,181
2014/15	1,209,920	3,378,622	-42,983	285,385	7,143	209,290	5,047,377
2015/16	1,237,362	3,378,258	-53,291	353,942	7,143	213,371	5,136,786
CAGR (11/12-15/16)	1.7%	-0.2%	48.5%	47.2%	0.0%	1.7%	1.5%

Table III-46: Base Case Normal Year Planning Load Results (Dth) – New Hampshire Division

Split Year	Residential	C&I Sales plus Capacity Assigned[51]	Energy Efficiency	Marketing Adjustment	Company Use	Losses and Unbilled Sales	Planning Load
2011/12	1,684,604	3,475,564	-24,863	69,031	631	90,865	5,295,833
2012/13	1,698,182	3,475,651	-41,914	133,248	631	92,670	5,358,466
2013/14	1,728,979	3,497,636	-58,962	198,996	631	94,246	5,461,526
2014/15	1,778,152	3,547,697	-76,003	268,427	631	96,225	5,615,129
2015/16	1,826,519	3,584,077	-93,039	339,086	631	98,718	5,755,992
CAGR (11/12-15/16)	2.0%	0.8%	39.1%	48.9%	0.0%	2.1%	2.1%

7. High and Low Growth Scenarios

In addition to the Base Case Planning Load results, forecasts based on scenarios of higher and lower than expected growth were also prepared to provide a range of outcomes for the Planning Load forecast. The High Growth scenario reflects an assumed annual growth that is 1% higher than the Base Case in each year of the forecast; the Low Growth reflects an assumed annual growth that is 1% lower

[50] C&I sales plus capacity assigned load includes capacity assigned Special Contract demand.

[51] C&I sales plus capacity assigned load includes capacity assigned Special Contract demand.

than the Base Case in each year of the forecast. Base Case, High Growth, and Low Growth Planning Load results for each Division are presented in Table III-47 and Table III-48 below.

Table III-47: Normal Year Planning Load Growth Scenarios (Dth) – Maine Division

Split Year	Base Case	High Growth	Low Growth
2011/12	4,833,649	4,890,923	4,776,541
2012/13	4,876,995	4,983,636	4,771,665
2013/14	4,949,181	5,107,208	4,794,603
2014/15	5,047,377	5,259,594	4,841,802
2015/16	5,136,786	5,405,318	4,879,189
CAGR (11/12-15/16)	1.5%	2.5%	0.5%

Table III-48: Normal Year Planning Load Growth Scenarios (Dth) – New Hampshire Division

Split Year	Base Case	High Growth	Low Growth
2011/12	5,295,833	5,365,566	5,226,409
2012/13	5,358,466	5,482,629	5,236,008
2013/14	5,461,526	5,642,917	5,284,339
2014/15	5,615,129	5,858,100	5,380,069
2015/16	5,755,992	6,063,633	5,461,240
CAGR (11/12-15/16)	2.1%	3.1%	1.1%

IV. Planning Standards and Design Forecasts

A. Introduction

The Company designs its gas supply portfolio to meet extreme cold weather conditions for a Design Year and a Design Day. To determine forecast firm Planning Load associated with design weather conditions, the Customer Segment firm demand and Company Use forecasts were calculated for 1-in-33 year design weather conditions. The Company's analysis of the required resources to meet the firm Planning Load requirements associated with normal and design weather conditions is presented in Section VI.

B. Weather Data

The Company's planning standards are based on an analysis of separate historical EDD data for the Maine Division (measured at the Portland, Maine weather station located at the Portland International Jetport) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station, located at Pease International Tradeport) for the period November 1, 1970 through October 31, 2010.

1. Climate Change Analysis

Climate change is a long-term change in the statistical distribution of weather patterns (which could include average weather conditions or a change in the distribution of weather events) over a defined period of time. A statistical analysis was prepared for this IRP to determine whether climate change was exhibited in the Maine and New Hampshire weather data. The analysis involved determining whether there was a difference in the ability of distributions comprised of 10, 20, or 30 years of historical EDD data to predict the weather in the next year, and if so, which was the best predictor. If climate change was significantly affecting the weather, the 10 year distribution may be a better predictor as it is based on a shorter period of history; whereas, if climate change was not significantly affecting the weather, the 30 year distribution may be a better predictor as it includes more history. 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 2007 and compared with the actual EDD that occurred in 2008. 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, and

January EDD. Results are presented in Table IV-1 for the Maine Division and Table IV-2 for the New Hampshire Division below.

Table IV-1: Climate Change Analysis – Maine Division

	Standard Error (RMSE)			% Improvement over 30 Year	
	10 Year Average	20 Year Average	30 Year Average	10 Year Average	20 Year Average
Gas Year	380.6	402.1	477.3	20.2%	15.7%
Winter	380.7	379.5	404.4	5.9%	6.2%
January	185.7	182.8	188.0	1.2%	2.8%

Table IV-2: Climate Change Analysis – New Hampshire Division

	Standard Error (RMSE)			% Improvement over 30 Year	
	10 Year Average	20 Year Average	30 Year Average	10 Year Average	20 Year Average
Gas Year	400.6	395.2	390.8	-2.5%	-1.1%
Winter	385.3	378.2	371.1	-3.8%	-1.9%
January	189.1	189.1	187.4	-0.9%	-0.9%

The climate change analysis indicates that there is no compelling evidence that Northern's EDD data is affected by a climate change effect. 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 equally good at predicting the following year EDD, with the 30 year average producing slightly better results. Based on an examination of the results and the desire to use consistent data sets across both Divisions, it was determined that the 20 year distribution was the most appropriate for predicting the following year EDD at this time. Therefore, the Normal Year, Design Year, and Design Day planning standards were developed using a database of the most recent 20 years of weather data for both the Maine and New Hampshire Divisions.

2. Normal Distribution Analysis

In addition, the weather data was examined to test whether Northern's historical EDD data is normally distributed. For both Divisions, four tests were conducted on the distributions of annual (gas year) EDD and peak day EDD. These tests included reviewing a histogram of the data, calculating the skewness and kurtosis of the data, and running the Kolomogorov-Smirnov test for normality. There was no evidence that the annual EDD or peak day EDD distributions for either Division did not follow a normal distribution. The details of these tests and their results are discussed in Appendices 6D and 7D. Since the data is normally distributed, traditional calculations of planning standards are appropriate.

C. Normal Year Planning Load

Although Northern plans its resources to meet design standards, Normal Year, or average year conditions, has a much greater probability of occurring. The Normal Year planning standard was determined to be 7,498 EDD for Maine and 6,996 EDD for New Hampshire. Consistent with the results of the climate change analysis, Normal Year EDD were calculated by summing the 20 year average EDD for each month using data from November 1, 1990 to October 31, 2010 (i.e., the most recent 20 gas years of data available at the time of the analysis). The 20 year monthly averages and total annual EDD for both Divisions are shown in Table IV-3 below.

Table IV-3: Normal Year EDD by Month

Month	Maine Division	New Hampshire Division
November	809	760
December	1,178	1,130
January	1,394	1,337
February	1,183	1,130
March	1,048	994
April	675	611
May	377	319
June	106	78
July	16	10
August	23	17
September	167	139
October	523	471
Winter	5,611	5,351
Summer	1,887	1,645
Total	7,498	6,996

To produce a string of daily normal EDD for the Normal Year that reflects the day-to-day randomness seen in actual EDD data, normal daily EDD were developed for each month by identifying a historical actual month with total EDD and standard deviation that were similar to the 20 year average for that month (a "typical month"). For each normal month, the same historical typical month was used for Maine and New Hampshire so that the weather patterns would be consistent in the two Divisions. Since the sum of the daily EDD in the selected typical month did not exactly equal the 20 year average, the EDD for each day in the typical month were adjusted by a proportional factor so the total for the month equaled the 20 year monthly average by Division. Repeating this process for each month of the year resulted in a daily string of EDD that represented a Normal Year and summed to the Normal Year total of 7,498 EDD for Maine and 6,996 EDD for New Hampshire.

To develop parameters for the daily load profiles that are inputs to the Company's SENDOUT® optimization model, a daily Planning Load model was developed for each Division. The dependent variable was historical daily Planning Load for the period May 1, 2009 through March 31, 2011 by Division. Daily historical Planning Load was developed by subtracting daily usage for capacity exempt customers from daily total throughput data. While historical total throughput data was available for longer periods of history, daily usage for capacity exempt customers was only available starting in May 2009. The independent variables for the daily Planning Load model included (1) actual daily EDD, (2) interaction terms of EDD by month, and (3) several dummy variables. For each Division, the coefficients of this daily Planning Load regression equation were used to develop monthly baseload and weather-sensitive components, which were then calibrated with the Base Case Normal Year results, which are summarized in Tables III-2 and III-3. The calibration process involved adjusting the baseload and weather-sensitive components for all months within a forecast season by a seasonal calibration percentage. The seasonal calibration percentages were determined such that the forecasted seasonal Planning Load calculated with the calibrated baseload and weather-sensitive components equaled the Customer Segment Planning Load forecast by season. The Company used the monthly calibrated baseload and weather-sensitive components to evaluate firm Planning Load requirements on a daily basis using the SENDOUT® optimization model, as discussed in Section VI below. The results of the daily Planning Load model, the preliminary monthly baseload and weather-sensitive components, the calibration factors, and the final monthly calibrated baseload and weather-sensitive components are contained in Appendix IV-2 for Maine and Appendix IV-3 for New Hampshire. As shown in these Appendices, the final calibrated baseload and weather-sensitive components produce Normal Year Planning Load results that are equal to the Normal Year Planning Load Base Case, High Growth, and Low Growth results summarized in Table III-47 and Table III-48 above.

D. Design Year Planning Load

The Design Year planning standard represents extreme winter conditions that have a statistically defined probability of occurring on a very infrequent basis. The Design Year standard is used to develop a forecast of Design Year Planning Load to establish the Company's resource requirements under extremely cold conditions. The Design Year planning standard was determined to be 8,178 EDD for Maine and 7,677 EDD for New Hampshire. The Company's Design Year standard is determined to result in a 1-in-33 year frequency of occurrence for the peak winter period (November through March), together with normal weather for the summer months (April through October).[52] Design winter EDD were calculated by first summing the EDD for each winter from 1990/91 through 2009/10 (i.e., the most recent 20 gas years of data available). The 20 year average and standard deviation of the winter EDD was calculated and used to calculate the winter EDD associated with a 1-in-33 year probability of occurrence. Monthly Design Year EDD for each of the five winter months were determined by adding the standard deviation for each winter month times an equal adjustment factor to the normal EDD for each winter month.[53] The Design Year monthly and total annual EDD for both Divisions are shown in Table IV-4 below.

Table IV-4: Design Year EDD by Month

Month	Maine Division	New Hampshire Division
November	907	855
December	1,307	1,262
January	1,586	1,538
February	1,333	1,275
March	1,158	1,102
April	675	611
May	377	319
June	106	78
July	16	10
August	23	17
September	167	139
October	523	471
Winter	6,291	6,032
Summer	1,887	1,645
Total	8,178	7,677

52 A 1-in-33 year frequency of occurrence was selected because it is consistent with the design standards used by other LDCs in the region.

53 The adjustment factor was calculated as follows: Adjustment factor = (Design Winter total EDD – Normal Winter EDD) / (∑ monthly standard deviations of winter months).

Similar to the analysis conducted for the Normal Year, to produce a string of daily EDD for the Design Year that reflects the day-to-day randomness seen in actual EDD data, design daily EDD were developed for each winter month by identifying a historical actual month that had total EDD and standard deviation similar to the Design Year for that month (a "typical design month"). Since the summer months in Design Year are assumed to equal the summer months in the Normal Year, the Normal Year daily pattern for the summer months was used. The historical typical design months were consistent between Maine and New Hampshire to produce coincident weather patterns. Since the sum of the daily EDD in the typical month did not exactly equal Design Year EDD for that month, the EDD for each day in the typical month were adjusted by a proportional factor so the total for the month equaled the Design Year monthly total by Division. Repeating this process for each month of the year resulted in a daily string of EDD that represented a Design Year and summed to the Design Year total of 8,178 EDD for Maine and 7,677 EDD for New Hampshire.

To determine the Planning Load associated with Design Year weather in each Division, the Customer Segment and Company Use models with EDD coefficients (i.e., Residential Heating use per customer, Residential Non-Heating use per customer, C&I LLF use per customer, C&I HLF use per customer, Maine C&I LLF transportation percentage, Maine C&I HLF transportation percentage, Capacity Exempt transportation percentages, Special Contracts, and Company Use) were re-run using design EDD in the forecast period. These Design Year Customer Segment results by Division were then reduced by the projected energy efficiency savings, increased for projected growth associated with marketing efforts, and adjusted for losses and unbilled sales to produce Design Year Planning Load, similar to the process used to develop the Normal Year Planning Load. Finally, High Growth and Low Growth scenarios were developed by increasing/decreasing the annual Base Case growth rates by 1%, similar to the Normal Year growth scenarios. Depending on the Division, year, and growth scenario, the Design Year Planning Load forecast is approximately 9% to 10% higher than the Normal Year Planning Load forecast. Table IV-5 and Table IV-6 below summarize the Design Year Base Case, High Growth, and Low Growth Planning Load for Maine and New Hampshire, respectively.

Table IV-5: Design Year Planning Load Growth Scenarios (Dth) – Maine Division

Split Year	Base Case	High Growth	Low Growth
2011/12	5,279,829	5,337,234	5,222,590
2012/13	5,332,398	5,443,678	5,222,431
2013/14	5,415,451	5,582,865	5,251,581
2014/15	5,524,436	5,751,027	5,304,772
2015/16	5,624,212	5,912,361	5,347,575
CAGR (11/12-15/16)	1.6%	2.6%	0.6%

Table IV-6: Design Year Planning Load Growth Scenarios (Dth) – New Hampshire Division

Split Year	Base Case	High Growth	Low Growth
2011/12	5,763,629	5,833,503	5,694,066
2012/13	5,835,675	5,964,688	5,708,368
2013/14	5,950,488	6,141,696	5,763,585
2014/15	6,116,544	6,374,563	5,866,733
2015/16	6,269,917	6,598,145	5,955,181
CAGR (10/11-15/16)	2.1%	3.1%	1.1%

The same daily Planning Load models that were used to develop the Normal Year baseload and weather-sensitive components were used to develop the Design Year baseload and weather-sensitive components. The calibrated Normal Year baseload components were also used for Design Year; the increased Planning Load in Design Year was assumed to be reflected in the weather-sensitive component. The calibration process for Design Year involved keeping the same calibrated baseload component from the Normal Year, and adjusting the weather-sensitive component for all months within a forecast season by a seasonal calibration percentage. The seasonal weather sensitive calibration percentages for Design Year were determined such that the forecasted seasonal Planning Load calculated with the Design Year calibrated baseload and weather-sensitive components equaled the Customer Segment Planning Load Design Year forecast by season. The Company used the monthly calibrated baseload and weather-sensitive components to evaluate firm Planning Load requirements for Design Year on a daily basis using the SENDOUT® optimization model, as discussed in Section VI below. The results of the daily Planning Load model, the preliminary monthly baseload and weather-sensitive components, the calibration factors, and the final monthly calibrated baseload and weather-sensitive components for Design Year are contained in Appendix IV-2 for Maine and Appendix IV-3 for New Hampshire. As shown in these Appendices, the final calibrated baseload and weather-sensitive components produce Design Year Planning Load results that are equal to the Design Year Planning Load Base Case, High Growth, and Low Growth results summarized in Table IV-5 and Table IV-6 above.

E. Design Day Planning Load

The Design Day planning standard represents extreme weather conditions on a single day that has a statistically defined probability of occurring on a very infrequent basis. The Design Day standard is used to develop a forecast of Design Day Planning Load that establishes the Company's resource requirements on a day of extremely cold conditions. The Design Day planning standard was determined to be 78.9 EDD for Maine and 80.5 EDD for New Hampshire. The Company's Design Day standard is determined to result in a 1-in-33 year frequency of occurrence.[54] Design Day EDD were calculated by first identifying the peak day EDD (i.e., the coldest day) for each winter from 1990/91 through 2009/10 (i.e., the most recent twenty gas years of data available, consistent with Design Year). The 20 year average and standard deviation of the peak day was calculated and used to calculate the Design Day EDD associated with a 1-in-33 year probability of occurrence. The Design Day EDD for both Divisions is shown in Table IV-7 below.

Table IV-7: Design Day EDD

	Maine Division	New Hampshire Division
Design Day	78.9	80.5

To determine the Planning Load associated with Design Day weather in each Division, a daily Design Day model was developed for each Division. Similar to the daily Planning Load model developed for Normal Year and Design Year, the dependent variable was historical daily Planning Load for the period May 1, 2009 through March 31, 2011 by Division and the independent variables included (1) actual daily EDD, (2) interaction terms of EDD by month, and (3) various dummy variables. For the Design Day model, additional independent variables were included for (1) days of the week (i.e., workdays, Fridays and Sundays), (2) increasingly colder temperatures (i.e., EDD base 55, base 45, base 35 or base 25)[55], and the prior day's EDD. For each Division, the parameters of this daily Design Day regression equation were used to develop the baseload and weather-sensitive components of Design Day Planning Load. The coefficients associated with the constant and the workday variables comprised the baseload and the coefficients associated with EDD, January EDD, the EDD base changes, and the prior day EDD variables comprised the weather-sensitive components of Design Day Planning Load. Substituting in the Design Day EDD for each Division produced preliminary Design Day Planning Load for each Division.

The preliminary Design Day Planning Load was then calibrated using the adjustment factors associated with Design Year January for each forecast year for the Base Case, High Growth, and Low Growth scenarios. The results of the daily Design Day model, the preliminary Design Day Planning Load, the calibration factors, and the calibrated Design Day Planning Load results are included in Appendix IV-2 for Maine and Appendix IV-3 for New Hampshire. Design Day Planning Load results for Base Case,

[54] A 1-in-33 year frequency of occurrence was selected because it is consistent with the design standards used by other LDCs in the region.

[55] EDD typically 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 less than 65 (e.g., 45) isolates colder days since days with average temperatures greater than or equal to 45 degrees have 0 EDD and days that are colder than 45 degrees have EDD = 45 – average temperature (adjusted for wind).

High Growth, and Low Growth are summarized in Table IV-8 and Table IV-9 below for Maine and New Hampshire, respectively.

Table IV-8: Design Day Planning Load Growth Scenarios (Dth) – Maine Division

Split Year	Base Case	High Growth	Low Growth
2011/12	52,353	52,827	51,879
2012/13	52,972	53,980	51,974
2013/14	53,848	55,412	52,313
2014/15	54,959	57,109	52,870
2015/16	56,011	58,774	53,353
CAGR (11/12-15/16)	1.7%	2.7%	0.7%

Table IV-9: Design Day Planning Load Growth Scenarios (Dth) – New Hampshire Division

Split Year	Base Case	High Growth	Low Growth
2011/12	52,778	53,258	52,299
2012/13	53,538	54,557	52,529
2013/14	54,580	56,164	53,026
2014/15	56,021	58,209	53,896
2015/16	57,435	60,260	54,717
CAGR (11/12-15/16)	2.1%	3.1%	1.1%

F. Cold Snap Scenario

In addition to analyzing Design Year and Design Day, the system's ability to meet customer requirements is tested during a prolonged 7-day cold period (i.e., a cold snap). A Cold Snap is defined as the 7 consecutive days with the greatest total EDD in the entire historical data set, again assumed to be coincident for both Divisions. By those criteria, the Cold Snap is defined by the weather that occurred during the period from February 11, 1979 to February 17, 1979. In that 7-day period, the Maine Division experienced a total of 513 EDD (for an average daily EDD of 73) and the New Hampshire Division experienced a total of 479 EDD (for an average daily EDD of 68). The Company utilized the SENDOUT® model to determine the Planning Load associated with the Cold Snap in each Division, and to test the Company's ability to provide resources during a Cold Snap.

V. Demand Side Resources

A. Introduction

The implementation of natural gas demand side management (e.g., energy efficiency) programs raises unique challenges relative to forecasting natural gas sales and developing a long term resource plan. On the one hand, such programs have the potential to alter the sales trends which form the basis of sound resource planning. At the same time, such programs offer a potential opportunity to offer cost effective solutions to customers in controlling their energy costs.

The purpose of this Section is to address these challenges and provide an explanation of the Company's approach to the integration of energy efficiency programs with its forecasting and supply planning processes. This explanation is intended to comply with the requirements of the Settlement Agreement approved by the Maine Public Utilities Commission in Docket 2006-390 and approved by the New Hampshire Public Utilities Commission in Docket No. DG 06-098, that the Company address Demand Side Management in its next Integrated Resource Plan filing.

The review of Demand Side Resources is organized into six sections. Section B. provides an overview of the energy efficiency program planning and implementation process and discusses issues involved in integrating this process with the resource planning process. Section C. provides an outline of the Company's current portfolio of energy efficiency programs in New Hampshire. Section D. provides a description and analysis of Energy Efficiency Actual and Projected Savings and explains how these are integrated into the sales forecasting process. Section E. contains an assessment of energy efficiency potential and Section F. provides a review of natural gas avoided costs. In Section G. the Company provides an analysis of the potential costs and savings associated with expanded energy efficiency programs. Section H provides conclusions and recommendations.

B. Energy Efficiency Program Planning and Implementation

Over the past decade, many state jurisdictions, including New Hampshire and Maine, have implemented and/or expanded energy efficiency programs for customers of natural gas utilities. In this context, Unitil developed and implemented gas energy efficiency programs in all three states in which it operates. The New Hampshire programs, for Northern Utilities' New Hampshire customers, began in 2003 and the programs for Northern Utilities' Maine customers began in 2006, while the Massachusetts programs date back more than ten years.[56] These programs involve ratepayer funding through supplemental charges billed to all natural gas customers.

In New Hampshire, energy efficiency is under the oversight of the Public Utilities Commission. Increasingly, the utilities have been working collaboratively to design and implement what are referred

[56] The utility energy efficiency programs In Massachusetts were expanded significantly beginning in 2009 in response to the Green Communities Act of 2008, which codified certain requirements including the principle that gas and electric utilities would be required to develop and implement plans to achieve all cost effective energy efficiency.

to as the CORE energy efficiency programs. In 2010, the Commission moved to a two-year planning process, and the utility CORE plans, including both gas and electric utilities, were filed on a joint basis for the period of 2011 and 2012. The development, filing and review of those plans and their implementation and evaluation involves an extensive collaborative process involving Commission Staff, utilities and other stakeholders, and the CORE plans reflect considerable commonality between utilities. The proceeding was initiated by the Company along with National Grid NH and the CORE electric companies, and after an extensive review by PUC Staff, the Office of Energy and Planning, the Office of the Consumer Advocate, and other intervenors, a Settlement Agreement was reached. The Agreement, and the 2011-2012 plans, were approved by the Commission in Order No. 25,189 in Docket DE 10-188. Approval of an update for the 2012 plan year is pending but has not been factored into this report.

In Maine, the gas energy efficiency programs were originally developed by Northern Utilities and approved by the Maine Public Utilities Commission. A start-up program began in 2006, and then the Company undertook a three-year program cycle which ended in April 2010. Northern Utilities was acquired by Unitil in December 2008. As of July 1, 2010, pursuant to new state legislation, the responsibility for energy efficiency planning and implementation was transferred to the Efficiency Maine Trust ("EMT"). For the period July 2010 through June 2011, as agent for EMT, Northern Utilities continued to implement most of the natural gas energy efficiency programs for its customers in Maine, however that contract has ended and the natural gas program implementation is now being conducted by the EMT. Northern Utilities continues to collect an Energy Efficiency Charge from customers and remits the funds to the MPUC for transfer to the EMT.

In general, the planning process for energy efficiency programs is a "bottom-up" exercise. Analysis of energy efficiency opportunities begins with specific energy efficiency measures, their costs and their applicability to specific customer segments. Programs are designed to target those measures and segments through specific incentives and delivery methods, and cost-effectiveness screening on a total resource cost basis is performed. Programs with positive cost-benefit ratios are grouped together into a portfolio of programs for residential, low-income and commercial/industrial customer groups, and detailed savings targets and program budgets are developed based on assessments of the demand for the programs. This process involves a variety of iterations and trade-offs. Over time, programs and the measures included in given programs evolve as the underlying costs, benefits and trade-offs change.

The most important trade-off that needs to be factored into overall program design, and specifically the level of program activity, is the impact on customer rates. Utility energy efficiency programs provide significant benefits in the form of bill reductions and reduced energy consumption to program participants, but these benefits are funded directly through charges assessed to all customers. This increases rates to all customers, whether they are able to participate in these energy efficiency programs or not. In addition, energy efficiency programs rely on current customer funding to implement measures providing benefits over the measure lifetime – essentially requiring up-front ratepayer funding for benefits experienced over a period of years. In the stakeholder and regulatory processes which govern energy efficiency plans and implementations, the rate and bill impacts are an important consideration.

An additional trade-off of increasing concern to the Company, in light of the potential for significant increases in energy efficiency program funding, relates to fact that natural gas competes directly with other fuels, specifically including home heating oil and residual oil for large businesses. As a consequence, there are inter-fuel substitution effects for changes in relative prices. A retail price for natural gas which deviates from market prices by adding significant costs for energy efficiency programs will result in substitution of oil for natural gas on the margin since oil fuels do not have similar energy efficiency charges in retail prices. Over time, this pricing disparity could result in relative increases in consumption of oil and corresponding relative decreases in consumption of natural gas with negative public consequences. These changes would not be absolute, i.e. decreasing actual consumption of natural gas, but they would be relative, causing a decrease in what the consumption of natural gas would have been had the increase in costs for energy efficiency not been imposed.

One of the key factors driving program design changes is evaluation and monitoring, which is a key element of energy efficiency implementation. In addition to verifying that the savings expected from specific measure installations have actually been achieved, these studies will assess the effectiveness of the program from a process standpoint, and will also review questions such as free-ridership (the savings would have occurred anyway without the program) and spillover (additional savings occur that were not actually paid for by the program). A second key factor influencing program design and implementation is avoided costs, e.g. the accumulated costs that would be incurred by the utility but-for the implementation of energy efficiency, which determine what the value is of the savings being achieved.

In the design process, there are also frequently a number of different stakeholders involved that may have an interest in specific programs or customers segments. These interests can also influence the resulting program designs, budget and implementation.

For a given planning period, once the program designs are complete and the overall budget levels established, a final screening of the energy efficiency measures within each program is prepared utilizing installed cost and the latest savings data to verify cost effectiveness and provide a final fine-tuning of the programs and measure mix within programs. The overall objective is to reach the highest level of savings while managing program costs and allowing many different types of customers to participate. Upon completion of program design, the energy efficiency savings goals and budgets must be approved by the appropriate governing authority. Once approved, the programs are implemented. For the Company administered programs in New Hampshire, within a given planning period, program spending may vary within limits without regulatory approval, but large variances are subject to subsequent review and approval.

Several features of this process have important implications for efforts to integrate demand side resources with the supply planning process. First, the demand resources that are acquired through the energy efficiency program design and implementation effort are generally long-lived resources, with average measure lives that exceed 15 years. In comparison, the average contract term in the supply portfolio is only 6 to 7 years. As a result, in the context of supply planning, the demand side resources have to be viewed as long term fixed commitments which cannot be amended, released or sold once they are in place. By contrast, supply resources typically involve a cost structure that requires certain fixed demand payments and variable commodity payments that are made over time as the resource is used. This cost structure provides some ability to manage overall cost by varying use of the resource or reselling the resource. Second, the timeframe for demand resource acquisition extends over a period of years and reflects significant uncertainties relative to the pace, cost and success in achieving a given level of demand resource acquisition. Many of the demand resource programs offered provide incentives that fund only a portion of the investment in efficiency measures; thus, the utility does not have direct control over demand resource acquisition. Utilities can offer programs to their customers, but cannot compel participation. In combination with the long-lived nature of the measures acquired, this means that the decision points for demand resource acquisition cannot be synchronized with the decision points for supply resources acquisition. Specifically, demand resource acquisition timelines are far more lengthy and effectively must occur prior to supply resource acquisition timelines.

Attempts to integrate demand resources into the supply planning process are further complicated by the unbundled nature of Northern's system. Northern provides energy efficiency programs to all customers, but only provides supply to its sales service customers. This inconsistency means that an integrated analysis of demand and supply resources might yield conclusions that do not represent the lowest reasonable cost alternatives for all customer groups. Planning to acquire additional demand side resources that end up being tied to efficiency measures installed at a transportation customer's facility will not contribute to the portfolio.

In addition, the rate implications of demand side resources are fundamentally different than the rate implications of supply side resources. Supply side resources typically include both fixed price commitments and variable commodity pricing, and they are paid for at the time the resource is used. In contrast, demand side resources are paid for by ratepayers up front, at the time the measures are installed. As such they involve fixed, advance payments and the benefits are only received over the period of the measure life. More significantly, the benefits from demand side resources are largely retained by the program participants installing the demand side measure, rather than being shared equally among all ratepayers. Supply resources are used by all ratepayers and paid for by all ratepayers. This difference in allocation of costs and benefits creates important equity and efficiency considerations relative to demand side resource allocation that must be factored into the regulatory oversight process. Finally, the procedural aspects of demand side resource acquisition and payment are fundamentally different from those involved in supply resource acquisition. Demand side resources are developed and implemented in the context of specific legislative and regulatory authority and of processes which involve stakeholder engagement and collaboration as well as direct regulatory oversight of program design and implementation.

In summary, demand side resources are, in essence, a public policy option to achieve greater public benefit at an overall lower cost. Acquiring supply resources is, in contrast, a fundamental obligation of the public utility to meet customer demand – this is not an option.

C. Current Energy Efficiency Programs

The following paragraphs outline the current programs Northern offers its New Hampshire customers. Typically the Company markets its programs via its website, word of mouth, bill stuffers, postcards, tradeshows, and sponsorships. Additionally, there is collaborative marketing with the Gas Networks® Consortium on the Residential High-Efficiency Heating, Water Heating and Controls program and the C&I New Equipment and Construction program. Programs have different implementation strategies, each designed to maximize savings relative to costs to achieve for the target measures and selected customer segment. Prior to July 1, 2011, the Company offered a similar portfolio of programs to its customers in Maine. The portfolio is subject to change under EMT implementation. However, over time, the Company would expect a similar range of programs to be available across all customer segments.

1. Residential Programs

Home Performance with ENERGY STAR® – This is a weatherization program marketed to homeowners. Customers are screened via a Home Heating Index tool located on www.NHSaves.com. The program provides an energy audit at a cost of $100 to customers. For all cost effective measures, customers are presented with installed costs (with 50% incentive applied up to $4,000 total), energy savings, dollar savings, and paybacks. Building Performance Institute certified Contractors are selected at the beginning of the program year and are assigned to customers by the Company.

Residential High-Efficiency Heating, Water Heating and Controls - This program is generally marketed and implemented by trade allies but no compensation is paid to them. The incentive is designed to pay for the incremental cost for energy efficient equipment to replace end of life equipment. Incentives are set by the Gas Networks Consortium. For a few pieces of equipment, the NH Gas Utilities diverted slightly from Gas Networks and used their own incentive form.

ENERGY STAR Homes (discontinued in 2011 but proposed for 2012) – This program is for new construction. A HERS Rater is contracted with at the beginning of the program year. The Rater conducts the Energy Star analysis and advises the builders on meeting Energy Star Homes standards. The Company works with builders to join the program.

Income Eligible - Unitil has partnered with New Hampshire's Weatherization Assistance Network to offer our customers the Home Energy Assistance Program (HEAP). This statewide program provides up to $4,500 in energy efficiency improvements to income-qualified households that may be especially vulnerable to increasing energy costs. All products and services provided by HEAP are provided to qualified participants free of charge**.**

2. Commercial and Industrial Programs

Large C&I Retrofit – This program is implemented by Company staff (Account Executives). Large commercial and industrial customers using more than 40,000 therms per year qualify for an incentive of up to 50% of the qualified installed cost of identified energy efficiency upgrades, up to a maximum of $50,000 per master meter.

Small Business Energy Solutions – This program is implemented by a contractor chosen on an annual basis. Small commercial and industrial customers using up to 40,000 therms per year qualify for an incentive of up to 50% of the qualified installed cost of identified energy efficiency upgrades, up to a maximum of $50,000 per master meter.

New Equipment and Construction – This program has two components. Prescriptive incentives are offered towards the installation of high efficiency gas furnaces, hot water boilers and water heaters, as well as controls and food service equipment in commercial and industrial applications. All commercial and industrial customers qualify for this program. It is designed to pay for the incremental cost for energy efficient equipment to replace end of life equipment. Incentives are set by the Gas Networks Consortium. For custom equipment not falling under the prescriptive incentive list, customers can receive an incentive of 75% of the incremental cost of the energy efficiency measure.

Multi-Family – This program is implemented by a contractor chosen on an annual basis. For qualified multi-family building customers, the Company will share a portion of the cost to design, purchase and install any qualified energy efficiency upgrades for multi-family building customers. The Company will pay 50% of the qualified installed cost up to a maximum of $50,000 per master meter. Eligible multi-family buildings have four or more units, a master-metered account on a firm commercial rate, and must use gas for heat and/or hot water.

D. Energy Efficiency Actual and Projected Savings

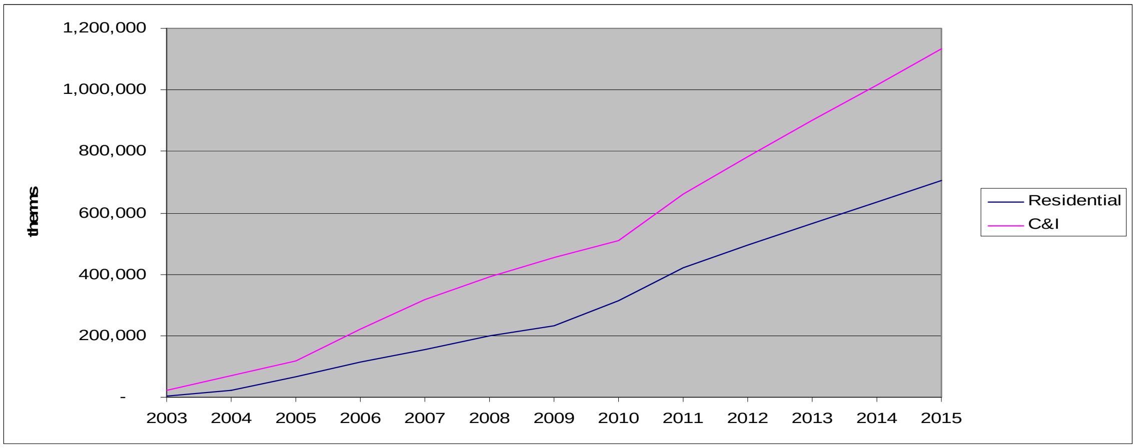
Actual natural gas sales in a given year are influenced by a variety of factors including the price of natural gas and its competing fuels (largely heating oil), weather, the economy, the addition of new customers, and changes in customer usage brought about by, among other things, energy efficiency programs paid for by charges to natural gas customers. The Company collects data on the measures installed in order to assess the impact of each ratepayer funded energy efficiency program so they can be independently evaluated and appropriate changes in budget levels and expected participation can be proposed. For New Hampshire program activity, data on the impact of the Company's energy efficiency programs is maintained pursuant to the ongoing review and oversight of utility energy efficiency programs which includes a strong monitoring and verification component. However, as of July 1, 2011, Northern no longer has responsibility for, or involvement in, the design, implementation or monitoring of natural gas energy efficiency programs in Maine. Those responsibilities now rest exclusively with the Efficiency Maine Trust. The information for Maine reflected in this report is based on the Company's prior energy efficiency experience in Maine[57], which is assumed to be a reasonable basis for future projections.

The projected energy efficiency savings reported below reflect estimated reductions in energy consumption from measures already installed and expected to be installed over the forecast horizon. As such, they do not reflect impacts from broad changes in natural gas usage patterns by customers, such as those resulting from changes in building or appliance codes or standards or from evolutionary changes in commercially available technologies or in consumer purchasing behaviors that are not directly caused by ratepayer funded energy efficiency programs. Such impacts are less certain and tend to occur over long timeframes. As a result, these types of effects would be appropriately captured in the statistical modeling performed for the demand forecast.

Figure V-1 depicts the historic and projected annual natural gas savings resulting from the Company's energy efficiency programs in New Hampshire for the period beginning in 2003 when the Company first implemented energy efficiency programs. Figure V-2 provides projected savings information for natural gas energy efficiency programs in Maine. In compiling the NH projections, the Company assumed that the current level of program implementation as provided for in the two-year energy efficiency plan approved by the NHPUC in Docket No. DE 10-188 will be continued through the forecast period of 2015/2016. The energy savings estimates factor in specific estimates of measures that have been or will be installed in a given year, the level of savings to be derived from each measure, and the expected lifetime of the measure. The chart shows the effect of the ramp up in spending on energy efficiency programs in 2011 and 2012. Northern increased its energy efficiency charge and budget by approximately 90% for 2011 and 2012. Once installed, DSM measures become embedded among the many drivers that influence customer demand and are reflected in historical usage patterns. Consistent with the treatment of DSM savings in the forecast, expected savings from approved programs and budget levels are treated as a reduction in demand.

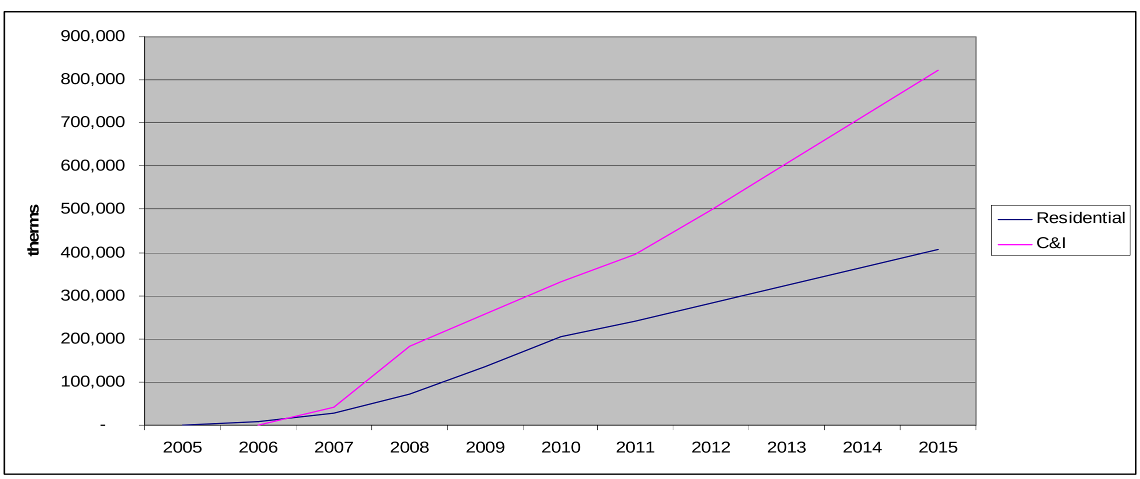
[57] Currently, the Company is uncertain whether it will have access to ongoing information such as savings estimates and monitoring and evaluation results for energy efficiency programs in Maine.

Figure V-1: Annual Energy Efficiency Program Savings - New Hampshire



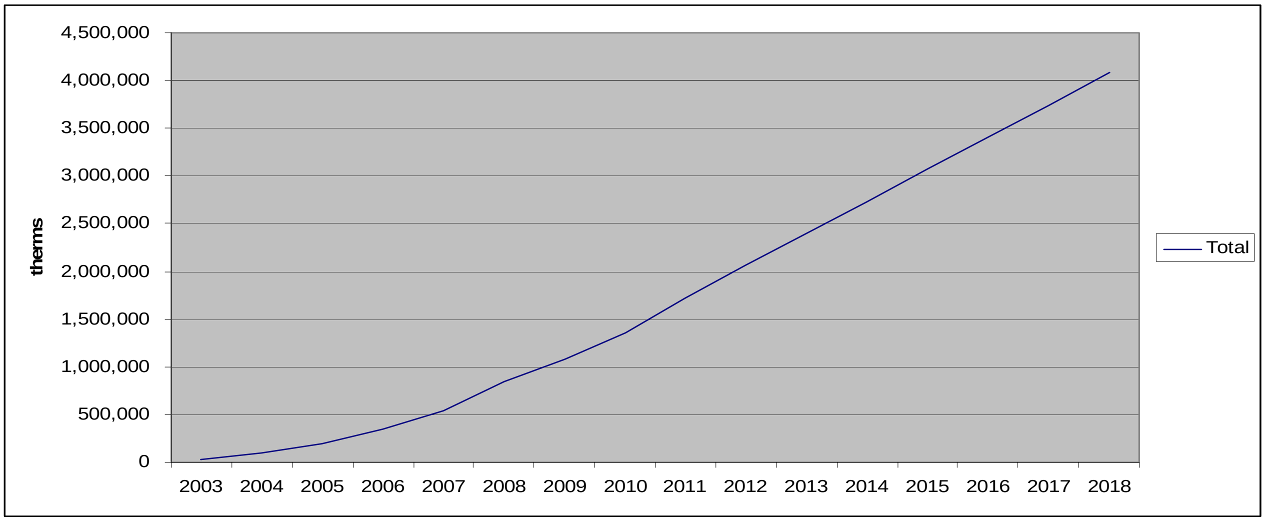
For Maine, the Company extrapolated the energy efficiency program activity from the period prior to July 1, 2011, the last period for which it was responsible for implementation of the natural gas energy efficiency programs pursuant to the oversight of the MPUC, through the forecast period. The Company no longer manages the natural gas energy efficiency programs for its customers as that responsibility has shifted to the Efficiency Maine Trust ("EMT"). The Company understands that EMT intends to continue the energy efficiency programs at approximately the same spending level reflected in 2011 for at least the period of the initial Three Year Plan which began as of July 2010. Figure V-2 shows the effects of the ramp up in energy efficiency spending for the period beginning in 2006 (the first year of implementation) and the expected pattern of savings under the assumption that spending and savings under the EMT programs continues at the same level through the forecast period.

Figure V-2: Annual Energy Efficiency Program Savings - Maine



The summation of historic and projected energy efficiency savings from the energy efficiency programs in both states is depicted below in Figure V-3. This chart has been extrapolated to 2018 to facilitate the analysis of potential savings in the following section. The chart shows the jump up in energy efficiency savings over the past few years, and a steady accumulation of savings thereafter reflecting the assumption that energy efficiency program activity will continue at current levels. The increases in annual savings values shown in these charts provide the basis for the incremental changes in sales resulting from energy efficiency factored into the Company's demand forecast in Section III-D of this report.

Figure V-3: Annual Energy Efficiency Program Savings - New Hampshire and Maine



E. Potential Energy Efficiency Savings

The Company reviewed the findings presented in the January 2009 report entitled "Additional Opportunities for Energy Efficiency in New Hampshire", which was prepared for the state of New Hampshire by GDS Associates, Inc. ("GDS Study"). The GDS Study estimated energy savings potential for the State of New Hampshire as a whole and for individual electric and gas utilities, including Northern, over a ten year period ending in 2018.

The GDS Study evaluated energy efficiency savings at four different levels: Technical Potential ("TP"), indicating the maximum level of savings potentially achievable through the complete and immediate application of all known technology deemed technically feasible; Maximum Achievable Potential ("MAP"), representing the share of TP associated with the maximum penetration of efficient measures regardless of cost or customer behavior assuming replacement of all standard efficiency equipment upon the end of its useful life and universal adoption of efficient equipment for new construction; Maximum Achievable Cost Effective ("MACE"), representing the portion of MAP determined to be cost effective according to the Total Resource Cost ("TRC") test; and, finally, the Potentially Obtainable Scenario energy efficiency savings which provides an estimate of realistic penetration over time, given that it takes into account customer behavior, but would require a sustained, aggressive marketing campaign to achieve. The level of cumulative annual savings estimated for Northern's New Hampshire customers is summarized in Table V-1.

Table V-1: GDS Study Cumulative Annual Savings (2018, Northern New Hampshire Division)

	Cum. Annual Savings (Therms)
Technical Potential	18,087,098
Maximum Achievable	13,031,170
Max. Achievable Cost Effective	10,429,611
Potentially Obtainable Scenario	5,160,044

According to the GDS Study, under the Potentially Obtainable Scenario, cumulative annual savings in Northern's New Hampshire Division could reach 5.2 million therms or 520,000 Dth by 2018. By comparison, Northern projects cumulative annual savings of 2.4 million therms or 240,000 Dth in 2018 from the ongoing operation of existing programs at current budget levels, or slightly less than one half of the Potentially Obtainable Scenario from the GDS Study. Northern's Maine service territory is similar to its New Hampshire territory in terms of the number and type of customers. Northern extrapolates cumulative annual program savings of 1.7 million therms in 2018 or 170,000 Dth for its customers in Maine, or about one third of the GDS Potentially Obtainable Scenario.

Northern will implement the energy efficiency budgets approved by the NHPUC, and bill its Maine customers the energy efficiency charges approved by the MPUC for services provided by EMT. However, in recent experience, Northern has been unable to fully subscribe its existing annual energy efficiency budgets and it is therefore unclear whether it would be successful in attracting customers to participate at such increased rates while maintaining costs at levels that continue to meet TRC test thresholds. In addition, as discussed in the next section, the GDS Study was prepared on the basis of avoided cost study results available at the time. The results of the more recent 2011 AESC Report are reviewed in the following section. The reduction in avoided costs would be expected to reduce the estimates of MACE and Potentially Obtainable energy efficiency savings below the levels reported in the GDS Study.

F. Review of Avoided Cost Estimates

Approximately every two years, a New England regional consortium of utilities and agencies contracts for the preparation of an "Avoided Energy Supply Costs in New England" report ("AESC

Report")[58]. The report provides projections of marginal energy supply costs that would be avoided as a result of reduced energy consumption due to energy efficiency programs offered throughout New England. The AESC Report provides program administrators with estimates of avoided costs to support internal decision making and regulatory filings for cost-effectiveness analyses. Each state's regulatory agency approves or disapproves of the values in each category listed. Northern accepts the avoided cost estimates from the AESC Report for DSM planning purposes.

Projections of future costs are determined as if no new energy efficiency is implemented in 2012 and beyond. The costs listed are not projections of future market prices. Market prices will vary from avoided costs due to several factors that affect short-term market prices at any time. The report provides projections of avoided costs from 2012 to 2026 and extrapolated values from 2027 to 2041. Values are reported in 2011 dollars.

The 2011 AESC Report describes changes that contributed to the reduction in avoided cost projections provided in the 2009 AESC Report, including:

- Dramatic increases in the quantity of recoverable shale gas along with the decrease in the expected cost to locate, develop, and produce gas from shale resources.
- A delay in federal regulation of carbon emissions from 2013 to 2018
- Lower gas distribution margins

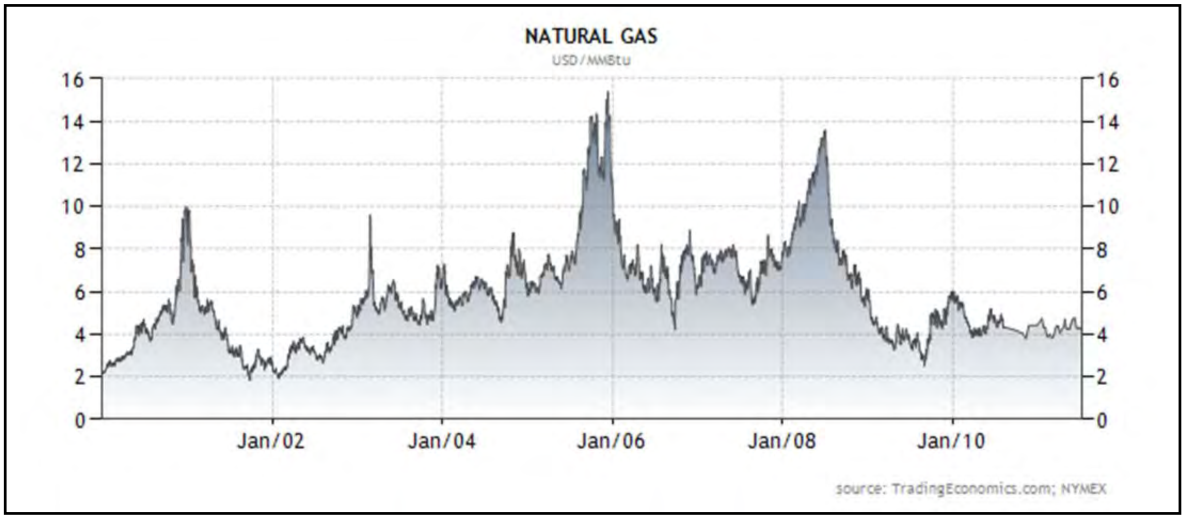
According to the report, gas energy efficiency programs have several cost benefits:

- Avoided gas supply costs due to reduced quantities of gas produced, transported, and stored for winter use.
- Avoided gas costs of local distribution infrastructure due to reduced or delayed need for newly built infrastructure.
- Avoided environmental impact due to the reduction in the quantity of gas being burned.

The latest AESC Report (2011) issued by Synapse indicates that the avoided cost of natural gas is \$0.68/therm (All C&I) in 2011 and \$0.84/therm in 2018. This is a reduction of nearly one-third from the levels estimated two years ago in the 2009 AESC Report. This significant drop is consistent with recent trends in Natural Gas prices, as depicted in Figure 4 below, which depicts Natural Gas commodity prices for the past ten years. Natural Gas commodity costs are currently nearly their lowest levels seen in the past 10 years.

[58] The AESC Reports prepared to date have been developed by Synapse Energy Economics, Inc. ("Synapse").

Figure 4: Natural Gas Historic NYMEX Prices



The following table indicates the changes in avoided costs per MMBtu (All C&I) by comparing the avoided cost estimates for gas utilities in Northern and Central New England from the 2009 and 2011 AESC Reports. The C&I All Gas avoided cost projection has declined by 36.5% for 2011, and by 30.2% for 2018. Application of these lower avoided cost values may have a significant impact on future evaluation of energy efficiency program cost-effectiveness.

Table V-2: Comparison of AESC Report Avoided Costs - 2009 to 2011 (C&I All Gas) $/MMBtu

	2009 Report	2011 Report	Delta
2011	$10.71	$6.80	36.5%
2012	$11.22	$7.28	35.1%
2013	$11.24	$7.49	33.4%
2014	$11.32	$7.84	30.7%
2015	$11.42	$8.33	27.1%
2016	$11.57	$8.36	27.7%
2017	$11.76	$8.34	29.1%
2018	$11.99	$8.37	30.2%

G. Potential Costs and Savings of Expanded Energy Efficiency Programs

In Section C above, we determined that the existing level of energy efficiency programs for Northern's gas customers in New Hampshire and Maine could potentially be increased, based on the Potentially Obtainable level of savings estimated by GDS. In determining whether such an increase is feasible or appropriate, the Company has reviewed the costs used by GDS in its study and the Company's actual program experience to date.

The Annual Costs evaluated in the GDS Study are installed costs of measures excluding the costs of program administration. In addition, the GDS Study utilized the incremental costs of higher energy efficiency for equipment measures, and utilized the total installed costs for weatherization measures.

Program administration costs are a significant and unavoidable requirement for the planning, design, regulatory review and evaluation of energy efficiency programs. It is therefore appropriate to factor in these costs in analyzing energy efficiency program costs. For 2011, program administrative costs for Northern's natural gas energy efficiency program in New Hampshire are projected to be 45% of total spending. In addition, Northern's programs generally require a cost sharing contribution on the part of customers. On average since 2008, Northern's rebate / customer incentive awards were at 57% of the measure installation cost (incremental cost for equipment / total cost for weatherization).[59]

The Table below provides a compilation of the savings and costs from the GDS Study, with the addition of a factor for program incentive levels (column C) and for program administration (column E). Column F reflects the total of all costs. Column G represents the total utility costs (excluding the customer share). In addition, Columns H and I provide the calculation of the costs per therm – sometimes referred to as the "cost to achieve", relative to both the total costs and the utility-only costs, respectively. The values reflected in the table below are for Northern's New Hampshire customer base only – adding the Maine customer base would roughly double the savings and cost values.

Table V-3: GDS Study Annual Savings, Costs, and Utility Costs (2008$)

	A	B	C	D	E	F	G
	2018 Annual Savings (therms)	Annual Installed/ Incr. Cost	Incentive 57% x B	Balance B-C	Program Admin.	Total Cost C+D+E	Total Utility Cost C+E
Technical Potential	18,087,098	$26,058,527	$14,853,360	$11,205,167	$12,368,996	$38,427,523	$27,222,356
Maximum Achievable	13,031,170	$16,148,071	$9,204,400	$6,943,671	$7,664,878	$23,812,949	$16,869,278
Max. Achievable Cost Eff.	10,429,611	$4,934,960	$2,812,927	$2,122,033	$2,342,439	$7,277,399	$5,155,366
Potentially Obtainable	5,160,044	$1,970,214	$1,123,022	$847,192	$935,186	$2,905,400	$2,058,208

[59] Comparable values from Northern's energy efficiency programs in Maine are somewhat different. For the period ending July 1, 2010, (the final 14 month period for which Northern operated the full portfolio of energy efficiency programs pursuant to MPUC oversight), the average rebate level was 35%, and program administration as a percentage of total utility spending was 26%. However the Company's energy efficiency programs in Maine were not at the same level of maturity as in New Hampshire, and that specific year was not representative as program demand significantly outstripped expectations, with over-spending funded by penalty funds from a prior and unrelated proceeding. For purposes of the analysis here, the Company believes the New Hampshire values for these parameters are the most appropriate and accurate to use.

	H	I
	Total Cost per therm (F / A)	Utility Cost per therm (G / A)
Technical Potential	$2.12	$1.51
Maximum Achievable	$1.83	$1.29
Max. Achievable Cost Eff.	$0.70	$0.49
Potentially Obtainable	$0.56	$0.40

As Table V-3 indicates, the total cost to achieve is $0.56/therm for Potentially Obtainable energy efficiency, compared to $2.12/therm for the Technical Potential level of savings, which demonstrates the point that the deeper the level of savings per year, the higher the cost per therm. This is to be expected since the "lower hanging fruit" of more cost-effective measures are typically projects that more easily meet with customers' acceptance and are simplest to implement first.

To evaluate the implication of the GDS Study cost and cost-to-achieve estimates, it is necessary to inflate the value to 2011$. In addition, this allows the GDS Study values to be compared to the actual cost experience of the Company in implementing its energy efficiency programs in 2011. The following table compares Northern's current investment (including the shareholder incentive) to the GDS Study adjusted for inflation by 3% annually from 2008 to 2011. Again, the values reflected in the table below are for Northern's New Hampshire customer base only – adding the Maine customer base would roughly double the savings and cost values. The cost to achieve values would remain the same.

Table V-4: GDS Study Annual Savings and Costs compared to Northern Savings and Costs for 2011

	A	B	C	D	E	F	G
	2018 Annual Savings (therms)	Annual Installed/ Incr. Cost	Incentive 57% x B	Balance B-C	Program Admin.	Total Cost C+D+E	Total Utility Cost C+E
Technical Potential	18,087,098	$28,474,856	$16,230,668	$12,244,188	$13,515,936	$41,990,792	$29,746,604
Maximum Achievable	13,031,170	$17,645,433	$10,057,897	$7,587,536	$8,375,619	$26,021,052	$18,433,516
Max. Achievable Cost Eff.	10,429,611	$5,392,564	$3,073,762	$2,318,803	$2,559,646	$7,952,210	$5,633,407
Potentially Obtainable	5,160,044	$2,152,906	$1,227,156	$925,750	$1,021,903	$3,174,809	$2,249,059
Northern 2011*	2,400,000	$1,018,514	$580,553	$437,961	$483,450	$1,501,964	$1,064,003

	H	I
	Total Cost per therm F / A	Utility Cost per therm G / A
Technical Potential	$2.32	$1.64
Maximum Achievable	$2.00	$1.41
Max. Achievable Cost Eff.	$0.76	$0.54
Potentially Obtainable	$0.62	$0.44
Northern 2011	$0.63	$0.44

* Savings are from Figure V-2, Costs are as filed in DE 10-188.

The Northern 2011 and the GDS Study Potentially Obtainable Cost per therm are closely matched - $0.63 for Northern and $0.62 for the GDS Study on Total Costs. Notably, the cost to achieve utilizing the total costs (Column H) is essentially an aggregate TRC test. In the table above, the values are lower than the AESC Report avoided costs discussed in the prior section for both the Northern program and the GDS Potentially Obtainable level. The GDS MACE level is higher than the avoided costs in 2011 and lower than the avoided cost level in 2018. A true TRC evaluation would require an assessment of measure costs and savings by year over the lifetime of the measure. The full technical potential and maximum achievable cost to achieve are well above the avoided cost values.

Northern's 2011 and 2012 projected spending for energy efficiency activities is approximately $1.1M per year in New Hampshire, and in Maine the projected spending by the EMT under the Three Year Plan is about $1M per year. In order to meet the level of spending and to achieve the same level of savings indicated in the above table, Northern's spending on energy efficiency would have to increase by the multipliers indicated in the table below. The energy efficiency charge per residential customer would need to be raised from $25 in 2011 to the amounts listed in the second column.

Table V-4: Multiplier and Annual Cost for Northern Customers

	Annual Cost Multiplier	Annual Cost/ Res. Cust.
Technical Potential	28.0	$699
Maximum Acheivable	17.3	$433
Max. Achievable Cost Eff.	5.3	$132
Potentially Obtainable	2.1	$53

The analysis above provides a hypothetical assessment that a doubling (or more) of energy efficiency program activity and spending could possibly be successful in achieving a higher level of savings and still remain cost-effective. However, translating this hypothetical assessment into a truly cost-effective program design and implementation plan will be difficult, both from a process and regulatory standpoint as well as a technical and administrative standpoint. In order to achieve higher penetration rates associated with the higher savings levels reflected in the Potentially Obtainable Scenario, more intense marketing activity and perhaps higher levels of incentive would be required, which would both reduce cost effectiveness relative to the numbers presented above. In addition, as demonstrated in the table above, ramping up energy efficiency significantly would have implications in terms of increasing rates.

Significantly, there are a variety of barriers in place that could thwart the efforts to accomplish deeper savings through higher spending levels. Among these barriers we note the following:

- The low retail cost of natural gas making paybacks too long ($1.09/therm - NH Office of Energy and Planning July 7, 2011). Residential customers may not be in their homes long enough to realize the payback. Businesses can often invest in other projects with shorter paybacks.
- Savings are generally not guaranteed by energy service providers. Customers may not choose to use available cash or take on a monthly loan payment for energy efficiency improvements when there is no savings guarantee from their contractor.
- Residential customers often rate energy efficiency improvements as less important than aesthetic home improvements for increasing the value of their homes. Real Estate professionals are just starting to list homes as “energy efficient” or “Energy Star” but generally no value of savings is included with this information.
- Lack of available cash to install energy efficiency measures and unwillingness to borrow required funds.
- Lack of customer awareness regarding returns on investment for energy efficiency projects. For example: a 5 year payback is equivalent to a 20% tax free return.
- Lack of customer awareness that over the long term energy prices may rise due to government environmental regulations and increasing demand for natural gas due to a national economic recovery.
- Lack of customer awareness that natural gas is a commodity and like other commodities is subject to price instability such as high swings realized in 2005 and in 2008.

In order to reach the “potentially obtainable” levels of spending and savings, existing programs would need to be expanded by allowing less cost-effective measures to qualify. Also, new programs would have to be added including some that currently do not meet the TRC test. For example, the following programs could be expanded or added:

- Residential High-Efficiency Heating, Water Heating and Controls program could be expanded to include a higher incentive for inefficient equipment that is not at the end of life. The same holds true for the C&I New Construction program.
- Home Performance with Energy Star program could be expanded to include individually metered buildings such as condominiums.
- Residential and C&I Energy Star Window and Door Replacement programs could be added.
- Residential and C&I Solar Hot Water Domestic Water Heating programs could be added.
- C&I Retro-commissioning program could be added.
- Residential and C&I Solar Hot Water Space Heating programs could be added.
- Residential and C&I Solar Hot Air Space Heating programs could be added.
- Residential and C&I Solar Hot Water Pool Heating programs could be added.
- New Construction Super Insulated Homes program could be added.
- Deep Retrofit Homes program could be added. See Better/Best on page I-5 and I-6 of the GDS Study.
- Deep Retrofit Multi-family Homes program could be added. See Better/Best on page I-7 and I-8.
- Energy Star Dishwasher and Clothes Washer program could be added.

Finally, it is important to recognize that expected increases in energy efficiency program savings through increased spending as theorized in the above analysis may not actually materialize. Designing and implementing cost-effective energy efficiency programs is challenging, and ramping up those programs beyond levels previously experienced entails certain risks that the programs will not be successful. Expanding energy efficiency programs will require extensive stakeholder consultations, careful review of industry best practices and extensive regulatory review.

H. Conclusions and Recommendations

The Company presented in Section D. its methodology for integrating the impacts of ratepayer funded energy efficiency programs into the Company's sales forecast, which serves as the basis for its long term supply plan. The methodology includes a review of the estimated savings achieved by the implementation of these programs. The savings estimates are based on the detailed program planning and field implementation data generated pursuant to the comprehensive planning, evaluation and program oversight process discussed in Section B.

In Section G. the Company provided an analysis that a potential exists for a significantly increased level of cost-effective energy efficiency for Northern's natural gas customers, and in Section F. the Company also reviewed the avoided costs which determine the benefits which energy efficiency program savings are expected to yield. The cost to achieve this higher level of energy efficiency, based on the GDS Study, and the estimates of avoided costs in the AESC Report, suggest that in aggregate this level of increased energy efficiency would satisfy the TRC requirements and be deemed cost-effective. The Company has not, however, assessed the rate and bill impacts that such an increase in energy efficiency spending would entail, nor has it assessed the incremental marketing cost and participant incentive levels required to achieve higher penetration rates or evaluated the potential competitive impacts which could result.

Based on these findings the Company recommends the following:

1) Continue to evaluate and assess the methodologies for integrating energy efficiency program savings into the sales forecasting process as discussed in Section D. In this regard, the Company faces a particular challenge in Maine, since the Company is no longer involved in planning or implementation of energy efficiency for its customers and has no access to detailed program spending or savings data. The Company will evaluate the options for obtaining data from the EMT, or extrapolating its continuing program experience in New Hampshire to Maine and its knowledge of the revenues remitted to the MPUC for EMT administered natural gas energy efficiency in order to estimate a level of expected energy efficiency savings in Maine.

2) Based on the study presented in this report, prepare a white paper relative to the expansion of energy efficiency programs in New Hampshire for submission to the CORE energy efficiency stakeholders, including the Office of Consumer Advocate and the NHPUC Staff. The purpose of the white paper would be to explore the issues involved in expansion of the Company's natural gas energy efficiency programs and develop an appropriate consensus strategy in advance of the filing of the next two year CORE energy efficiency programs for the New Hampshire natural gas companies.

VI. Resource Portfolio Assessment

A. Introduction

This Resource Portfolio Assessment provides an overview of the process utilized by Northern to make long-term supply-side resource decisions to meet the Planning Load requirement.

Section B of the Resource Portfolio Assessment, "Current Portfolio and Supply Management," provides an overview of Northern's current supply-side resource portfolio. This includes a review of each resource in Northern's portfolio and how it is utilized by Northern to meet its current planning load requirements, a description of Northern's commodity supply procurement process, and a description of the daily, monthly and seasonal flexibility built into the current portfolio. An overview of Northern's financial hedging process is also provided.

Section C of the Resource Portfolio Assessment, "Resource Balance," provides a Design Day, Design Year and Design Winter Resource Balance analysis in order to determine the level of additional supply-resources required to reliably meet Northern's Planning Criteria through the five-year planning period (the 2011-2012 gas year through the 2015-2016 gas year) covered in this IRP. Due to projected load growth and the expiration of long-term supply-side resources in accordance with their contract terms, Northern requires incremental or replacement supplies beginning the second year of the planning period.

Section D of the Resource Portfolio Assessment, "Supply Resource Alternatives," lists the supply-side resources, which could potentially be secured by Northern in order to meet the Planning Load requirement. These supply-side resources include both the renewal of existing resources and the identification of potential new supply sources.

Section E of the Resource Portfolio Assessment, "Resource Optimization Analysis," then provides an overview of the Company's Sendout® modeling process. This includes an overview of the seven Planning Load demand scenarios analyzed, commodity price and pipeline rate forecasts, and the process for modeling and evaluating the economics of potential new supply-side resources or renewal of existing supply-side resources to Northern's portfolio. This section also provides the results of the Sendout® analysis, including commodity costs, total costs (inclusive of fixed costs) and load duration curves for each Planning Load demand scenario. A Cold Snap Analysis is also presented, based upon the Resource Optimization Analysis. Section E also presents Northern's preferred portfolio and a review of each of the individual contract renewal decisions, as determined through this assessment. The Resource Balance analysis is restated to reflect these indicated contract decisions.

B. Current Portfolio and Supply Management

In order to meet Northern's planning load requirements; Northern has acquired a supply-side resource portfolio, which includes transportation and underground storage resources, delivered supplies, and on-system LNG storage and production. Northern's supply-side resource portfolio for the upcoming 2011-12 gas year is summarized below in Table VI-1.

Table VI-1: Summary of Northern Supply Resources – Maximum Daily Quantity

Table VI-1. Summary of Northern Supply Resources - Maximum Daily Quantity (Dth)		
Supply Resource:	Winter Capacity (Nov - Mar)	Summer Capacity (Apr-Oct)
Washington 10 Path	32,885	0
Tennessee Longhaul	13,109	13,109
Chicago Path	6,434	6,434
Tennessee Niagara	3,282	3,282
Tennessee FS-MA & 5265	2,644	2,644
PNGTS Year-Round	1,096	1,096
Total Transportation and Underground Supply Resources	59,450	26,565
Peaking Supply 1	9,965	0
Peaking Supply 2	9,965	0
Peaking Supply 3	11,958	0
Lewiston Baseload	5,500	0
Total Delivered Supplies	37,388	0
Lewiston On-System LNG Production	10,000	10,000
Total Northern Supply Resources	106,838	36,565

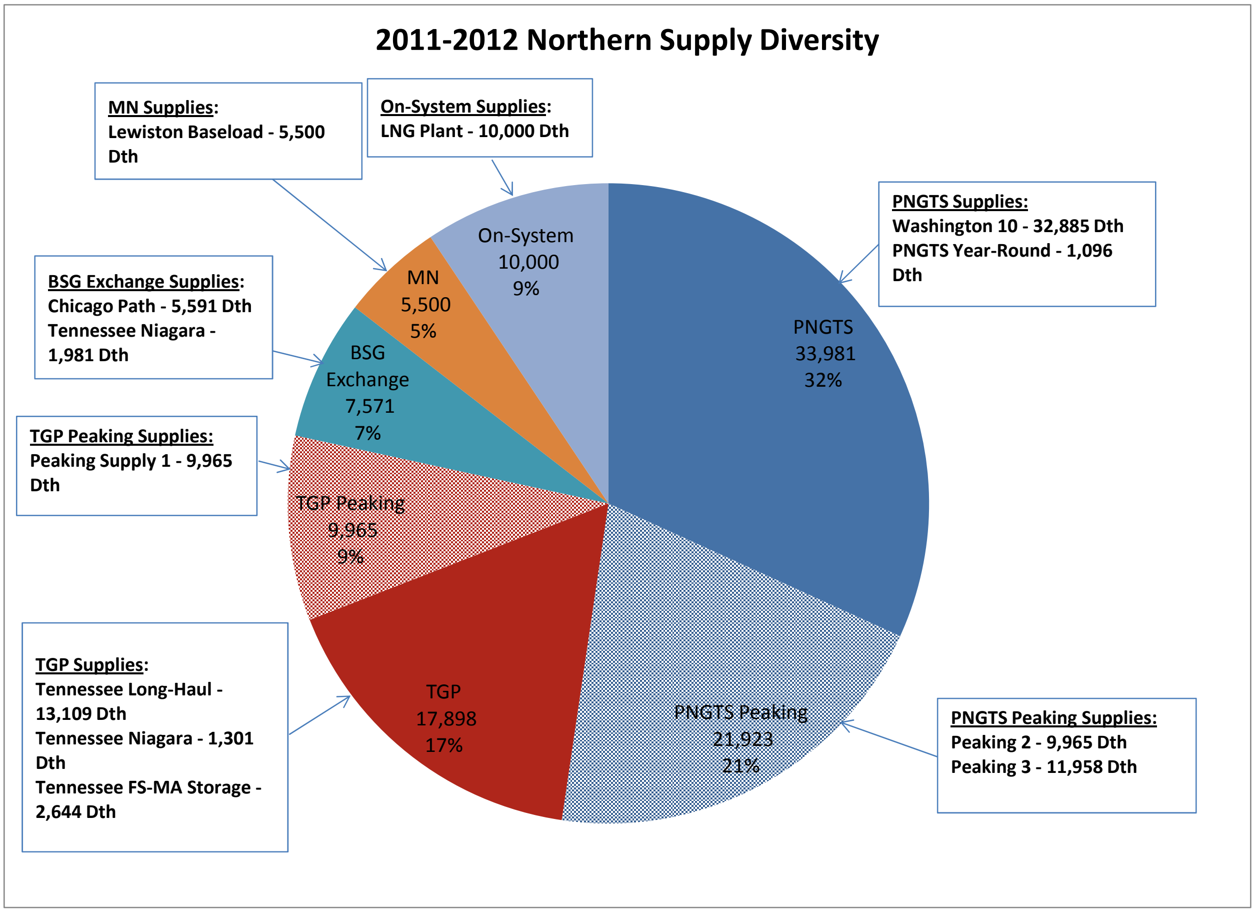
Please refer to Appendix VI-1 for capacity path diagrams and capacity path details, which show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, in order to move natural gas supplies from the supply resources listed in Table VI-1 to Northern's distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path diagrams show how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Northern accesses the wholesale natural gas market 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 and TGP to Northern city gates along the Granite system
- Maritimes & Northeast U.S. ("Maritimes" or "MN U.S.") city-gate, located in Lewiston, Maine
- On-System LNG Facility, also located in Lewiston, Maine
- Interconnections between Portland Natural Gas Transmission System ("PNGTS") and Granite, located in Westbrook, Maine and Newington, New Hampshire
- Interconnection between Tennessee Gas Pipeline Company ("Tennessee" or "TGP") and Granite, located in Haverhill, MA or the Northern city-gate with Tennessee, located in Salem, New Hampshire
- Northern's exchange agreement with Bay State Gas Company ("BSG"), under which, Northern delivers supplies to BSG's Tennessee or Algonquin city-gates and BSG delivers supplies to Northern's Granite city-gates via either of the PNGTS interconnections with Granite

Northern seeks to maintain a balance between reliance upon PNGTS or MN supplies and TGP supplies within its portfolio. A balanced approach provides better supply reliability and portfolio flexibility than dependence upon a single entry point to the Northern distribution system. Figure VI-1, below, provides an overall summary of Northern's 2011-2012 winter portfolio, by entry point into the Northern distribution system. Please note that in most cases, TGP supplies can either be delivered to the interconnection between Granite and TGP or delivered to BSG's city-gate and ultimately delivered to the system via the interconnection between Granite and PNGTS.

Figure VI-1: Northern Resources – Maximum Daily Quantity, 2011-2012



The following provides a detailed description of each supply resource in Northern's portfolio:

1. Transportation and Underground Storage

Northern Utilities' resource portfolio is comprised of transportation and underground storage capacity contracts that collectively provide reliable and diversified supply to its system in order to meet design year as well as design day 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 unique transportation paths.

a) Washington 10 Path

The "Washington 10 Path" capacity is one of two "pathed" capacity groupings within Northern's portfolio. The capacity diagram and details for this supply resource are found on page 1 of Appendix VI-1. Northern combines Vector, TransCanada and PNGTS transportation capacity with Washington 10 storage capacity in order to deliver supplies to the interconnections between PNGTS and Granite. This capacity grouping is considered the heart of Northern's resource portfolio, because the supply source of this path is Northern's 3.4 BCF of storage space at the Washington 10 storage cavern in Michigan. The associated pipeline capacity allows for ultimate deliveries of up to 33,000 Dth/day on PNGTS. This path is released to an asset manager annually for a one year term in exchange for an asset management fee. By releasing this capacity to an asset manager, Northern bypasses Canadian border issues, and avoids the risk of trading and scheduling these assets. In the summer months, the asset manager ratably fills the storage for Northern. In the winter months, Northern relies upon the asset manager to effectively deliver storage gas from Washington 10 along the Vector, TransCanada, and PNGTS pipelines. Northern takes delivery of this gas at interconnects between PNGTS and Granite State, and pays the asset manager for the storage as it is withdrawn plus the applicable commodity-based costs of moving the gas from Washington 10 to the ultimate delivery to GSGT. Washington 10 storage represents the largest supply resource available within Northern's resource portfolio. Due to the characteristics of underground storage resources, the Washington 10 supply resource provides an operationally flexible supply at a known commodity price during the heating season.

b) Tennessee Long-haul

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 throughout 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 Northern Utilities' and Bay State's city gates as well as in zone 4 on the 300 leg at the injection meter for TGP's Northern Storage - FS-MA. The capacity diagram and details for this supply resource are found on page 2 of Appendix VI-1.

Northern releases a portion of this contract annually to an asset manager, and the remaining portion is used to fulfill baseload requirements at Northern and/or Bay State city gates as part of the Exchange. The portion that is asset managed is available for next day calls in the winter months. To fill the remaining capacity, Northern uses Gulf or zone 4 200 leg supplies, which are both in path to the delivery meters.

c) Chicago Path

The "Chicago Path" capacity is second of two "pathed" capacity groupings within Northern's portfolio. Northern combines Vector, Union, TCPL, Iroquois, TGP, and AGT pipeline transportation capacity within this path, which provide access to attractively priced Chicago index based supply plus applicable fuel and commodity charges necessary to make the ultimate deliveries to TGP and AGT. The capacity diagram and details for this supply resource are found on page 3 of Appendix VI-1. Northern releases this path annually to an asset manager for an asset management fee through an RFP process for a one year term. By releasing this path to an asset manager, Northern bypasses the inherent border issues that are associated with moving gas from Canada to the United States, mitigates the risk associated with trading and scheduling to fill this path of capacity, while maintaining access to the delivered product on TGP and AGT at the same prices it would had the capacity not been released. Currently, Northern receives a substantial asset management fee for this path, because the asset manager is able to use this freely in the off peak months. In the winter months, Northern utilizes this path by taking daily deliveries up to the amount of the full MDQ to serve its own system at the Pleasant St. Tennessee Z 6 200 Leg city gate, the Bay State Agawam Tennessee zone 6 200 Leg meter, and the Algonquin Bay State Brockton city gate. Deliveries made to Bay State city gates facilitate the Exchange between Bay State and Northern.

d) Tennessee Niagara

Northern has entitlements on three transportation contracts on Tennessee with primary receipts at Niagara in zone 5 on the 200 leg, and primary deliveries to zone 6 on the 200 leg at Bay State city gates and Pleasant Street. Northern receives the deliveries on TGP to Pleasant Street on its corresponding firm Granite State capacity to transport on Granite to Northern city gates. The capacity diagram and details for this supply resource are found on page 4 of Appendix VI-1.

These contracts are aggregated within Northern's portfolio, and are released to an asset manager in the RFP process annually. In the winter months, the total MDQ of all three contracts is available for monthly calls.

e) Tennessee FS-MA & 5265

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 withdrawal quantity is up to 4243 Dth a day. Northern injects ratably in the summer months to fill this storage space. In the winter months, Northern withdraws this supply to make deliveries to Northern's city gate in zone 6 using transportation contract 5265. The capacity diagram and details for this supply resource are found on page 5 of Appendix VI-1.

The primary receipt meter in this transportation contract is the FS-MA storage withdrawal meter, and the primary delivery meter is at Pleasant Street in Z6 on the 200 leg. Pleasant Street is the interconnection between TGP and Granite State. Northern receives this gas on its corresponding firm Granite capacity to make deliveries on Granite State to Northern city gates.

f) PNGTS Year Round

In addition to the seasonal firm capacity that Northern has on the Portland Natural Gas Transmission System, Northern has a year round firm contract on PNGTS. This contract allows Northern to receive gas at either its primary receipt meter at Pittsburg, NH or at the Westbrook, ME interconnect between Maritimes Northeast & U.S. and PNGTS on a secondary firm basis. From there, Northern delivers gas to the interconnections between PNGTS and Granite State at Westbrook (primary firm), Newington (secondary firm), or Eliot (secondary firm).[60] Northern receives those deliveries on its corresponding firm Granite capacity to effectuate deliveries to Northern's city gates. The capacity diagram and details for this supply resource are found on page 6 of Appendix VI-1.

[60] Please note that PNGTS has never restricted the use of secondary points.

Supply at Pittsburg, NH is Canadian supply sourced from the TransCanada interconnect with PNGTS at East Hereford in Quebec. Supply at the Westbrook, ME interconnect between Maritimes and PNGTS[61] is sourced from Maritimes supplies such as Canaport, Sable Island, and eventually new supply sources such as Deep Panuke.

Northern currently manages this capacity directly, rather than releasing it to an asset manager. Currently, the capacity has relatively little value within the context of an asset management deal due to excess capacity on PNGTS, but can provide Northern flexibility to seamlessly move supplies between the three interconnections between PNGTS and Granite, in order to provide an additional tool for balancing supply with demand behind each of these meters.

g) Algonquin (Texas Eastern Zone M3 Interconnection)

For the 2011-2012 gas year, Northern releases its capacity on Algonquin contract 93201A1C. Algonquin contract number 93201A1C provides rights to receive gas supply at the interconnection between Algonquin and Texas Eastern ("TETCO") pipeline in TETCO's Zone M3 and to deliver gas to Bay State's Algonquin city-gates. Beginning in the 2012-2013 gas year, Northern is exploring the option of utilizing this capacity to source a winter baseload supply in order to supply the Bay State Exchange. This change is intended to free up more of Northern's TGP-based supplies to supply the interconnection between GSGT and TGP in Haverhill, MA for the purpose of providing Northern more flexibility

h) Bay State Exchange Agreement

The Bay State Exchange Agreement is an agreement in which Northern Utilities, with the use of its firm Tennessee and Algonquin transportation entitlements, serves Bay State's city gates at Agawam on Tennessee Gas Pipeline and Brockton on Algonquin pipeline. In return, Bay State uses its firm PNGTS and Granite State entitlements to serve Northern Utilities' city gates located along the Granite State pipeline. Both parties benefit from this exchange as it is a means of meeting requirements without having to contract for additional firm pipeline capacity. This exchange allows each party to make the best use of assets that do not access their own distribution systems. The parties have mutually agreed to base load the current summer volume at 4300 Dth/day and the upcoming 2011-2012 winter volume at 12,000 Dth/day. On the colder days in the winter, if both parties are able, this Exchange can also be utilized as a peaking supply by increasing the volumes exchanged between the two parties to meet cold weather demand forecasts. Northern requires the Bay State Exchange Agreement in order to deliver portions of the Chicago and Niagara supply resources (Page 3 and 4 of Appendix VI-1, respectively). Northern may elect to also utilize the Bay State Exchange for the purpose of delivering Tennessee Long-haul or Tennessee FS-MA supply resources.

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[61] Please note the interconnection between Maritimes and PNGTS, referred to as "Westbrook," is a different meter than the interconnection between PNGTS and Granite, also referred to as "Westbrook." In order to move natural gas from the interconnection between Maritimes and PNGTS at Westbrook into Granite at Westbrook, one needs either to use PNGTS capacity to move the gas away from the PNGTS-Maritimes interconnection into the PNGTS-Granite interconnection or utilize the Maritimes Westbrook lateral for an additional fee.

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 Bay State Exchange Agreement, which is delivered directly to Northern's city-gates by Bay State. Like Northern, Granite is a subsidiary of Unitil Corporation. Granite operates an 87-mile pipeline, extending from Essex, Massachusetts, through New Hampshire to just northwest of Portland, Maine. Granite has three receipt meters on this pipeline. The Westbrook receipt meter interconnects with PNGTS and MN U.S. The Newington receipt meter interconnects with PNGTS. The Pleasant St. receipt meter interconnects with Tennessee Gas Pipeline. GSGT has thirty-four delivery meters on its system, which are each Northern city-gates in either Northern's New Hampshire or Maine Divisions. In addition to this pipeline, GSGT also owns and operates the interconnection between PNGTS and Northern, located in Eliot, Maine. GSGT has no on-system storage or compressor stations.

Unitil believes that issues the GSGT Integration Study has shown that the current GSGT configuration is optimal. As such, the IRP reflects GSGT as currently configured.

2. Delivered Supplies

a) Lewiston Cotton Road

The Lewiston, Maine area is the northern most portion of the Northern Utilities distribution system. Northern supplies a portion of the requirements for that part of the system by purchasing city gate delivered supply on the Maritimes and Northeast U.S. Pipeline. For the 2011-2012 winter season, Northern has purchased 5,500 Dth of baseload supply, delivered to the Cotton Road city-gate between Maritimes and Northern. The purpose of this purchase is to provide a portion of the supply for the Lewiston market, in order to limit reliance upon supplying the Lewiston market with gas received by Granite at Westbrook.

b) Peaking Supplies

For the 2011 - 2012 winter, Northern has procured three peaking supplies, each deliverable to Granite receipt meters. The capacity diagram and details for this supply resource are found on pages 7 through 9 of Appendix VI-1. These delivered peaking supplies provide reliability for Northern's gas supply portfolio by assuring that Northern has adequate volume of supply to serve Northern's design day planning load requirement and design winter planning load requirement. Each contract is structured as a daily call option. Commodity is priced at appropriate daily indexes. Please note that the current peaking contracts are short-term supplies and will likely terminate before the review of the Integrated Resource Plan is completed. Northern anticipates replacing these supplies on a short-term basis over the planning horizon.

3. On-System Peaking Facilities

Lastly, a resource that is a very important and effective resource within Northern's portfolio, is the Lewiston LNG facility. The Lewiston LNG facility has the ability to produce up to 10,000 Dth per day and store up to 12,000 Dth of LNG. This resource offers Northern numerous advantages that are not made available to Northern by any other resource or part of its portfolio. One advantage is a level of flexibility that cannot be attained by any other supply option in that Northern is able to run the plant so that volumes produced cross from one gas day to another. Any other means of supplying natural gas to a market is limited to a gas day specific (10 am – 10 am EST) timeframe. In addition to using the LNG facility as a peaking supply for the winter's coldest days, Northern utilizes this flexibility in order to meet intraday needs, to get through morning pulls, and colder Monday mornings than originally forecasted on Fridays when weekend gas was procured. Northern is also able to rely upon the Lewiston LNG facility as a local storage facility, and has contracted with GDF Suez a price based on the TGP Z6 200L first of month index that allows Northern to avoid exposure to gas daily price spikes that occur on peak days. The capacity diagram and details for the LNG plant are found on page 10 of Appendix VI-1.

4. Supply Procurement Process

a) Use of RFPs

Annually, Northern issues requests for proposal ("RFP's") in order to procure supply and to plan portfolio management for the upcoming year. The ever-changing market conditions and the State Retail Choice Programs require that Northern maintain a certain element of flexibility, therefore, Northern typically contracts for up to one year terms for supply and portfolio management services. Collectively, the results of the RFP's allow Northern to meet demand requirements and facilitate asset optimization. Northern receives responses to these RFP's from a large number of suppliers with diversified backgrounds, which allows Northern to secure cost effective options.

Northern generally follows the RFP process detailed below:

(1) Identify Requirements and Draft RFP

Northern bases its supply requirements on projected loads, its current portfolio of transportation and storage contracts, and operational experiences from prior years. This information is utilized to formulate a draft of the RFP.

For asset management bids, Northern identifies the resources to be managed, the volume and location that commodity is to be delivered, and the index prices upon which commodity deliveries are to be based. The suppliers are requested to bid the level of asset management payment they are willing to provide for each asset management package.

For natural gas supplies, Northern identifies the location and volume of commodity is to be delivered. Bidders are asked to provide the index upon which commodity prices are based and what (if any) demand payment is to be required.

For either asset management bids or natural gas supply bids, Northern indicates whether commodity volumes are baseload, monthly call option or daily call option.

Finally, for capacity release bids, Northern indicates what capacity is proposed to be released and the term of the proposed release.

(2) Identify Potential Suppliers

Potential suppliers include any wholesale gas marketer or producer, who has expressed interest in Northern's RFP. This includes any company, which currently has a base natural gas purchase and sales agreement with Northern, or has expressed interest in setting one up.

(3) Issue the RFP and Respond to Questions

Typically, after issuing the RFP, suppliers will have a number of questions related to the RFP. Northern responds to these inquiries promptly in order to provide suppliers with information they may require in order to formulate a bid.

(4) Receive and Evaluate Bids

Price and non-price information related to each bid is tabulated and summarized. Non-price parameters include financial viability of the supplier, operational flexibility offered and historic experience with the company. Northern selects winning bidders based upon the proposal that provides Northern with the best overall value.

5. Portfolio Flexibility

Northern's resource portfolio is capable of reliably meeting design day and design year requirements, and provides both monthly and daily flexibility to accommodate fluctuations in requirements. Such fluctuations can be attributed to various factors such as weather swings, changes within the retail choice environment, load growth and/or decreases, and market conditions that result in deviations from projected demand forecasts. Such flexibility within the portfolio also allows Northern to take advantage of opportunities for cost savings when possible. Please see Section IV.C.3, "Potential Variability in the Resource Balance" for additional comments on portfolio flexibility.

a) Seasonal, Monthly, Daily Fluctuations in Demand

When determining the seasonal and monthly supply plans, Northern plans for the normal weather. However, adequate supply is available to ensure that Northern has the ability to meet its design day, cold snap and winter conditions. In the case when demand is lower than anticipated, Northern's resource portfolio provides the flexibility necessary to make adjustments which prevent excess or idle capacity.

Northern's requirements vary seasonally, and can vary between low and high demand monthly and daily during any given season. In the winter, Northern's resource mix is comprised of monthly base load supply, monthly base load call options, daily storage withdrawals, and daily call options for peaking resources. Northern manages daily swings by adjusting storage withdrawal volumes, and meets cold snap requirements by calling upon peaking supplies. In the summer months, Northern's resource mix is comprised of monthly or seasonal base loads. Northern also makes off system sales in order to capture value and to manage upstream pipeline imbalances.

b) Retail Choice / Capacity Assignment

A significant portion of Northern's total distribution requirement is not supplied by Northern, but rather is supplied by Retail Suppliers operating within Northern's New Hampshire and Maine Divisions. On an annual basis, retail choice accounts for approximately 50% of the New Hampshire Division total distribution deliveries and 60% of the Maine Division total distribution deliveries. Changes within the retail choice environment often result in changes to Northern's load requirements. Deliveries by Retail Suppliers can vary due to changes in load or changes in market conditions. Although Northern's tariffs require Retail Suppliers to balance deliveries with requirements on a daily and monthly basis, Northern is ultimately responsible for ensuring it stays within the imbalance tolerances allowed by the upstream pipelines.

When a Northern customer switches from Sales Service to Transportation-Only Service, the retail marketer is assigned a share of Northern's pipeline, storage and peaking portfolio, in accordance with the relevant state tariff. The purpose of the capacity assignment program is to ensure that Northern's gas supply portfolio is sized in order to meet its current Sales Service obligations.

The basic provisions of the capacity assignment program for Northern's New Hampshire Division are as follows:

1. Any Customer, receiving Sales Service on or after March 1, 2000, who initiates Supplier Service, is assigned capacity at 100% of the Customer's estimated Peak Day Requirement. Once the Customer's share of capacity is established, it is unchanged so long as the Customer remains on Supplier Service.
2. Any Customer on Supplier Service on or before March 1, 2000 is not assigned capacity[62].
3. Any new Customer at a new service location, going directly to Supplier Service, is not immediately assigned capacity. Northern allows 120 days for new Customers at new service locations to initiate Supplier Service before assigning capacity.

[62] These customers had the option to elect capacity assign, subject to availability, as determined by Northern.

4. Each year, Northern notifies Retail Suppliers of Northern's capacity portfolio to be assigned by Northern. With some minor exceptions, this includes Northern's entire capacity portfolio. A portion of the capacity is released directly to the Retail Supplier through each pipeline's Electronic Bulletin Board. A portion of the capacity is "Company-Managed." Company-Managed capacity is controlled by the Company and not released to the Retail Supplier. In this case, the Company provides delivered supply service to the Retail Supplier.

The basic provisions of the capacity assignment program for Northern's Maine Division are as follows:

1. Any new Customer at a new service location, going directly to Supplier Service, is not assigned capacity. Northern allows 60 days for high-use and 120 days for low-use new Customers at new service locations to initiate Supplier Service before assigning capacity.
2. All other Customers initiating Supplier Service are assigned capacity based upon 50% of the Customer's estimated Peak Day Requirement. Once the Customer's share of capacity is established, it is unchanged so long as the Customer remains on Supplier Service.
3. No capacity is directly released to the Retail Supplier. All capacity is Company-Managed.
4. The capacity assignment portfolio includes Northern's Washington 10 storage and its peaking supply contracts. Retail Suppliers may nominate to purchase commodity through these resources for the months of November through March subject to maximum daily contract quantities ("MDCQ") and annual contract quantities ("ACQ").
5. The demand rate is equal to the annual cost of Northern's capacity, recovered over a five-month period. The commodity rate is intended to equal the Northern's average delivered cost of gas.

c) Asset Management Agreements

Northern structures AMA deals to fulfill base load and swing delivery obligations. Within such agreements, Northern makes available to itself up to the full MDQ of the assets released, and maintains the flexibility to allow for volume adjustments to accommodate swings. Any portion of the MDQ of the assets released that is not necessary for Northern to meet forecast requirements is available to the asset manager for their own means of asset optimization. In exchange for the assets released, Northern receives a fixed fee from the asset manager. Asset management agreements are one means by which Northern obtains value for unutilized capacity in its gas supply portfolio.

d) Capacity Releases

In the off-peak season, Northern may determine that there is excess capacity in the portfolio that is not necessary to meet demand forecasts. Northern will release this capacity to the highest bidder in an effort to recover demand costs that are passed through to the sales customers. During the RFP process, Northern selects a prearranged highest bidder, and then posts the prearranged offer on the pipeline electronic bulletin board where it is formally bid, awarded, and executed. In the case where the prearranged offer is biddable, this gives other interested parties an opportunity to outbid the prearranged bidder. Capacity releases are another means by which Northern obtains value for unutilized capacity in its gas supply portfolio.

e) Off-System Sales

Another means of balancing the portfolio to manage daily and monthly demand fluctuations is by making off-system sales. Once demand requirements are determined and fulfilled, and excess supply has been identified for a given day, Northern will occasionally sell the excess supply in the market if the price of the supply is lower than the market price. Off-System Sales are also utilized to balance the system when there is unusually warm weather. All off-system sales margins are passed through to the sales service customers.

f) Long-term Resource Contracting Flexibility

As discussed in Section VI.C, Northern has several new and existing supply options for meeting Northern's design day and year supply obligation. Northern considers the relative economics of these supply options as it makes current and future contracting decisions. Also, as discussed in Section VI.D, Northern plans to procure peaking supplies and delivered city-gate supplies on a year-to-year basis, rather than locking these supplies up for multiple years. This practice allows Northern the flexibility to match supply resources very closely with its projected planning load.

6. Financial Hedging Activities

Northern manages a financial hedging program as part of an overall strategy to provide a reasonable level of price stability to the cost of gas supply. Northern's financial hedging program was last reviewed and approved by the Maine and New Hampshire Commissions in 2010[63]. Under the program, Northern develops an annual plan that targets entering the winter heating season with 70% of supplies hedged or available at a fixed price and entering the summer period with 40% of supplies needed for the months of May and October hedged or available at a fixed price. The annual plans are established and approved as part of the spring cost of gas filings and cover a twelve month period that begins with the summer period one year hence. Purchases under the financial hedging program begin with the expiration of the May natural gas futures contract[64], twelve months before the following summer and eighteen months before the next following winter, the two seasons that comprise the period being hedged.

[63] See MPUC Docket 2008-093 and NHPUC Docket DG 09-141.
[64] Natural gas futures contracts expire three business days prior to the end of the prior month.

In developing an annual hedging plan, Northern first identifies its physical assets that provide for fixed prices, including underground storage and fixed price commodity contracts, and then supplements those with financial instruments. Once Northern establishes the number of natural gas futures contracts[65] required to reach the target seasonal hedging goals, a monthly purchasing schedule is developed such that a nearly equal number of contracts are purchased each month and the number of contracts by month reflects the shape of the load requirement. A ceiling price for each month of the period being hedged is calculated pursuant to a formula. Purchases are made each month upon the expiration of the prompt month contract according to the monthly purchasing schedule except when prices exceed the price ceiling, in which case purchases are suspended until prices fall to or below the price ceiling. Lastly, Northern monitors the market value of each futures contract in its portfolio and will sell any futures contract that appreciates by 40%.

Northern's most recent hedging plan calls for purchasing 28 futures contracts for the summer of 2012 and 122 contracts the winter of 2012-13. The 28 contracts for the summer of 2012 equate to 280,000 Dth, which is 40% of Northern's estimated supply requirement for the months of May and October, or 19% of the summer period requirement. The 122 contracts for the winter of 2012-13 equate to 1,220,000 Dth or 21.3% of the estimated 2012-13 winter period supply requirement. Taken together, the combined 150 futures contracts equates to 1,500,000 Dth or 20.7% of estimates annual supply requirements.

Transactions under the financial hedging program are simple purchases of natural gas futures contracts on the New York Mercantile Exchange Index (NYMEX). Thus, Northern's hedging programs is a dollar cost average, purchase and hold type of program, subject to the provisions for price ceilings and trigger to sell individual contracts upon appreciation of 40%. As part of the review of the hedging program mentioned earlier, there was consensus among Northern, the Maine Commission and the New Hampshire Commission that a certain amount of hedging made sense and the seasonal targets described resulted.

The Settlement Agreement asks Northern to describe why financial hedging is appropriate. The established goal of the hedging program is to protect rate payers from price spikes, so as to mitigate exposure to rate increases. The current program achieves this goal in a relatively efficient manner in that it achieves the established goal at a relatively low cost and with no counterparty risk since transactions are posted with a member of the exchange. Moreover, Northern has the ability under the current program to contract for fixed price physical supplies, which would offset the financial component of the hedging plan. Northern provides a monthly hedging report to both the MPUC and the NHPUC, as well as an annual hedging report to the MPUC. For the reasons stated above, and because the current design of the hedging program was the product of collaboration among the Company and the staffs of both Commissions, Northern's financial hedging program is appropriate.

[65] As described later in this section, Northern purchases NYMEX futures contracts, which are denominated in volumes of 10,000 MMBTU.

The actual purchasing of the futures contracts is conducted by Northern's introducing broker, Risk Management, Inc. (RMI). Once the annual plan is approved, Northern provides the purchasing schedule to RMI and reviews expectations with regard to the schedule, the price ceiling and the sale of contracts that appreciate by as much as 40%. Then, each month Northern reviews transactions from the prior month and sends subsequent written instructions to RMI for the coming month. In addition, Northern monitors program activity daily, verifying expected transactions and calculating margin requirements to assure availability of funds and maintenance of required margin. Monthly reporting is also conducted in order to maintain proper accounting for the program and to provide reports on program activity to the Maine and New Hampshire Commissions.

C. Resource Balance

Northern has prepared initial Design Day, Design Year and Design Winter Resource Balance calculations. The purpose of these calculations is to provide a current state of the portfolio, comparing Design Day, Year and Winter Planning Load requirements to the supplies currently under contract. For the purpose of the initial Resource Balance calculations, Northern assumes current contract commitments only.[66] By assuming only current contract commitments, Northern observes a significant shortfall in its Design Day Resource Balance, beginning in the 2012-2013 gas year. This reflects the expiration of several one-year peaking supply contracts, totaling approximately 32,000 Dth. Beginning the 2013-2014 gas year, Northern has Algonquin capacity on the Chicago path to consider for renewal. For the 2015-2016 gas year, Northern has Tennessee Niagara and FS-MA storage capacity contract to consider for renewal. One of the objectives of this Integrated Resource Plan is to discuss Northern's plans for renewing or replacing this capacity, if the supply is needed to meet Northern's design planning load requirements. In order to provide a current state of the portfolio, Northern presents the initial Resource Balance calculations, assuming that Northern takes no action on these sources of capacity and simply reduces its available supply-side resources. Further sections of this Resource Portfolio Assessment will discuss Northern's process for evaluating supply alternatives and determining renewal or replacement decisions. Northern's plan for addressing the current-state Design Day Resource Balance shortfall is discussed below.

1. Design Day Resource Balance (Comparison of Maximum Daily Resources to Design Day Planning Load Requirement)

Please refer to Appendix VI-2, which provides the Design Day Resource Balance under Base-, High- and Low-Case Demand Growth Scenarios for each Gas Year from 2011-2012 through 2015-2016.

[66] Currently, Northern has a one-year contract for LNG with a maximum annual volume of 125,000 Dth. For the purpose of the initial Resource Balance, Northern assumes that it will replace this contract each year of the planning period. The Lewiston LNG plant has the ability to vaporize 10,000 Dth of LNG per day and the facility is under Northern's control. It is reasonable to assume that Northern will purchase liquid supply in order to utilize the facility. Therefore, Northern recognizes the LNG plant as capacity for the purpose of the initial Resource Balance calculations.

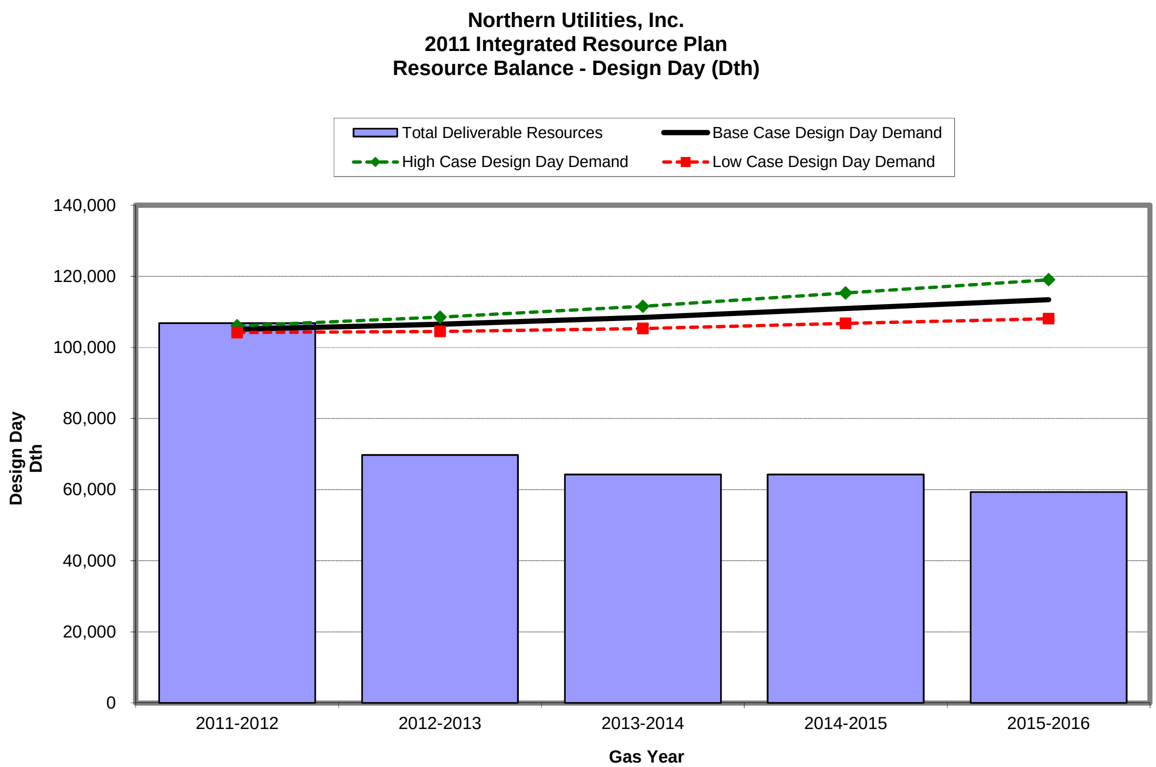
Page 1 of Appendix VI-2 provides this information in tabular form and Page 2 of Appendix VI-2 provides this information in graphical form. The comparison of Northern's maximum daily quantity of supply resources to its projected Design Day planning load requirement is summarized in Table VI-2, below.

Table IV-2: Summary of Design Day Resource Balance

Table VI-2. Summary of Design Day Resource Balance					
Item	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Total Resources	106,838	69,751	64,289	64,289	59,313
Base Case Design Day Demand	105,131	106,510	108,428	110,980	113,447
Base Case Design Day Resource Balance	1,707	(36,759)	(44,139)	(46,691)	(54,134)
High Case Design Day Demand	106,084	108,537	111,576	115,318	119,034
High Case Design Day Resource Balance	754	(38,786)	(47,287)	(51,029)	(59,721)
Low Case Design Day Demand	104,178	104,503	105,339	106,766	108,071
Low Case Design Day Resource Balance	2,660	(34,752)	(41,050)	(42,477)	(48,758)

This data is also presented in graphical form in Figure VI-2, below.

Figure IV-2: Chart of Design Day Resource Balance



For the purpose of presenting the initial Resource Balance, Northern reflects neither renewal options nor replacement capacity for existing resources, whose current contract term ends within the five-year resource planning period. For the 2011-2012 gas year, Northern shows a Design Day Resource Balance surplus of 1,707 Dth in the Base Demand Growth Case, 754 Dth in the High Demand Growth

Case and 2,660 Dth in the Low Demand Growth Case. Reflecting the expiration of contracts in accordance with their terms, Northern shows Design Day Resource Balance shortages in excess 30,000 Dth in each of the Demand Growth cases beginning in the 2012-2013 gas year. This largely reflects the short-term nature of the current peaking supplies. Referring to Appendix VI-2, the Design Day Resource Balance shortage is due primarily to reductions in Total Deliverable Resources, due to the expiration of contracts within both the Chicago and Tennessee Niagara capacity paths, the Peaking Supply contracts and Lewiston Baseload following the 2011-2012 gas year. Following the 2014-2015 gas year, Northern's Total Deliverable Resources would be further reduced by the expiration of the Tennessee Niagara and Tennessee FS-MA storage contract and associated Tennessee transportation contract #5265. The specific contract-level renewal decisions created by these contract expirations are detailed in the Section VI.E.3, Indicated Contracting Decisions.

The largest resource reduction from a Design Day perspective is the expiration of the peaking supply contracts. In the near term, Northern plans to issue annual RFPs in order to address its peaking supply requirements. In these RFPs, Northern will consider both one-year and multi-year peaking proposals in order to address the projected Design Day Resource Balance shortage. As discussed further in this report, there are ample resources available for meeting Northern's Design Day requirements. Therefore, Northern is confident that a short-term procurement process will be sufficient to ensure system reliability.

2. Design Year Resource Balance (Comparison of Maximum Annual Resources to Design Year Planning Load Requirement)

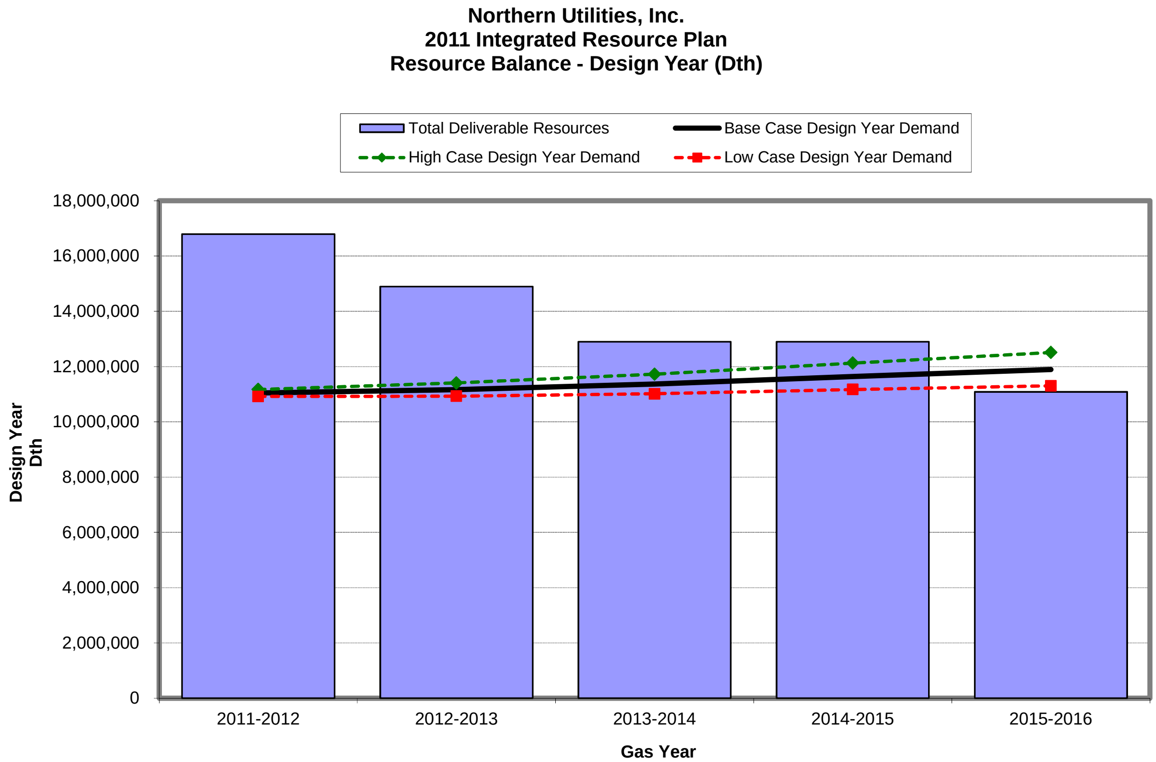
Please refer to Appendix VI-3, which provides the Design Year Resource Balance under Base-, High- and Low-Case Demand Growth Scenarios for each Gas Year from 2011-2012 through 2015-2016. Page 1 of Appendix VI-3 provides this information in tabular form and Page 2 of Appendix VI-3 provides this information in graphical form. The comparison of Northern's maximum annual deliveries of supply resources to its projected Design Year planning load requirement is summarized in Table VI-3, below.

Table VI-3: Summary of Design Year Resource Balance

Table VI-3. Summary of Design Year Resource Balance					
Item	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Maximum Resources - Design Year	16,793,230	14,896,725	12,903,095	12,903,095	11,086,855
Base Case Design Year Demand	11,043,458	11,168,073	11,365,939	11,640,980	11,894,129
Base Case Design Year Resource Balance	5,749,772	3,728,652	1,537,156	1,262,115	(807,274)
High Case Design Year Demand	11,170,737	11,408,366	11,724,561	12,125,590	12,510,506
High Case Design Year Resource Balance	5,622,493	3,488,359	1,178,534	777,505	(1,423,651)
Low Case Design Year Demand	10,916,655	10,930,799	11,015,166	11,171,505	11,302,755
Low Case Design Year Resource Balance	5,876,575	3,965,926	1,887,929	1,731,590	(215,900)

This data is also presented in graphical form in Figure VI-3, below.

Figure IV-3: Chart of Design Year Resource Balance



The Maximum Resources are calculated by multiplying the maximum daily quantity of each supply resource and the number of days per year each resource is available. The Maximum Resources reflects only those resources Northern has committed to for each contract year and does not reflect any contract renewals or replacements within the five-year resource planning period. For the 2011-2012 gas year, Northern shows a Design Year Resource Balance surplus of approximately 5.7 million Dth in the Base Demand Growth Case, 5.6 million Dth in the High Demand Growth Case and 5.9 million Dth in the Low Demand Growth Case. Referring to Appendix VI-3, the Design Day Resource Balance surplus decreases each year following the 2011-2012 gas year due to primarily to reductions in resources, due to the expiration of contracts, as discussed in the previous section. In the final year of the planning period, Northern projects to have a design year shortage in each of the design year scenarios studied.

Please note that a surplus in the Design Year Resource Balance does not indicate that Northern has adequate resources to meet Design Year conditions. As noted above, Northern does not have adequate resources to meet its planning load Design Day requirement after the 2011-2012 gas year. Whenever daily loads exceed the maximum daily quantity of Total Resources, Northern would require additional resources in order to meet this requirement. Also, the Design Year Resource Balance does not take into account the excess capacity Northern would have on days that the planning load requirement was less than the maximum daily quantity of Total Resources. Due to the increased amount of excess capacity in the summer, non-heating season, it is possible that a Design Year Resource Balance could appear to indicate that the portfolio was well balanced with requirements, when the system could be short during the winter months and long during the summer months. In order to better portray this potential issue with the use of Design Year Resource Balance as an indicator of whether the portfolio is balanced with planning load requirements, a Design Winter Resource Balance was also prepared and is presented in the next section.

a) Design Winter

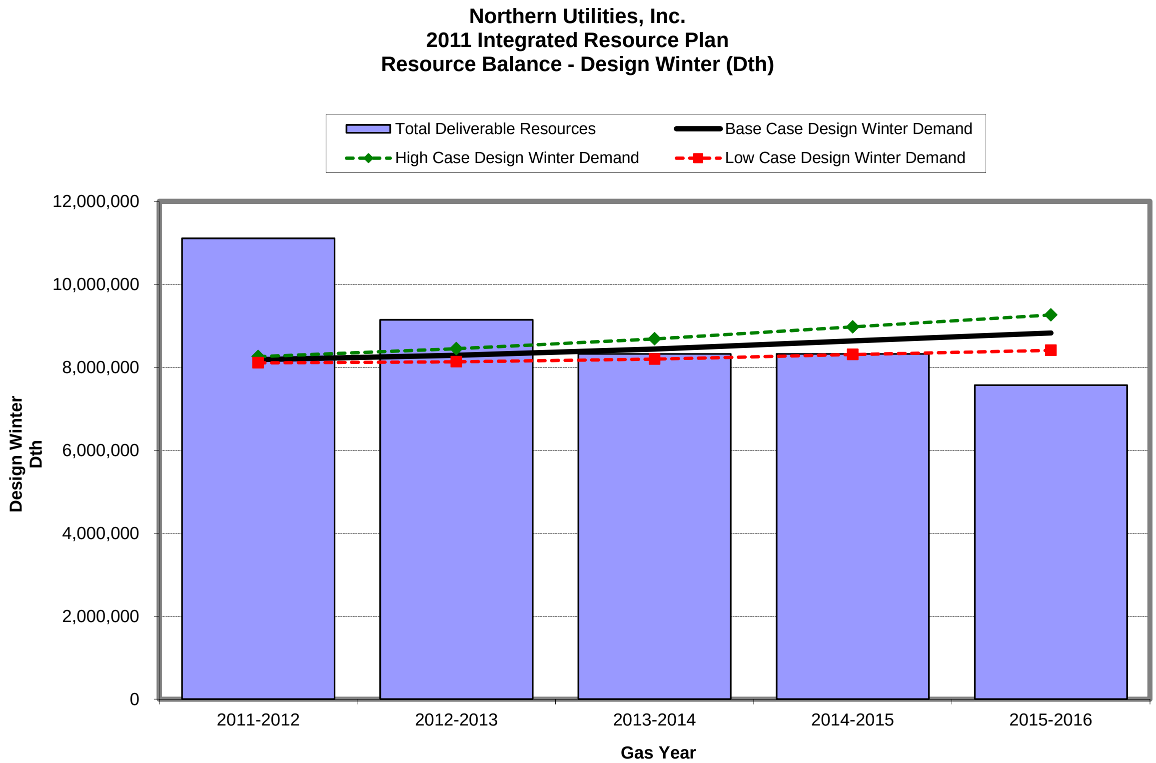
Please refer to Appendix VI-4, which provides the Design Winter Resource Balance under Base-, High- and Low-Case Demand Growth Scenarios for each Gas Year from 2011-2012 through 2015-2016. Page 1 of Appendix VI-4 provides this information in tabular form and Page 2 of Appendix VI-4 provides this information in graphical form. The comparison of Northern's maximum winter deliveries of supply resources to its projected Design Winter planning load requirement is summarized in Table VI-4, below.

Table VI-4: Summary of Design Winter Resource Balance

Table VI-4. Summary of Design Winter Resource Balance					
Item	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Maximum Resources - Design Winter	11,108,320	9,147,401	8,322,639	8,322,639	7,571,263
Base Case Design Winter Demand	8,185,480	8,291,992	8,440,425	8,638,042	8,828,841
Base Case Design Winter Resource Balance	2,922,840	855,409	(117,786)	(315,403)	(1,257,578)
High Case Design Winter Demand	8,260,193	8,450,280	8,686,049	8,976,277	9,264,308
High Case Design Winter Resource Balance	2,848,127	697,121	(363,410)	(653,638)	(1,693,045)
Low Case Design Winter Demand	8,110,766	8,135,199	8,199,473	8,309,454	8,409,901
Low Case Design Winter Resource Balance	2,997,554	1,012,202	123,166	13,185	(838,638)

The data is also presented in graphical form, in Figure VI-4, below.

Figure VI-4: Design Winter Resource Balance



The Maximum Resources are calculated by multiplying the maximum daily quantity of each supply resource and the number of days per winter each resource is available. The Maximum Resources reflects only those resources Northern has committed to for each contract year and does not reflect any contract renewals or replacements within the five-year resource planning period. For the 2011-2012 gas year, Northern shows a Design Year Resource Balance surplus of approximately 2.9 million Dth in the Base Demand Growth Case, 2.8 million Dth in the High Demand Growth Case and 3.0 million Dth in the Low Demand Growth Case. Referring to Appendix VI-4, the Design Day Resource Balance surplus decreases each year following the 2011-2012 gas year due primarily to reductions in resources, due to the expiration of contracts, as discussed previously. There are additional reductions in resources, beginning the 2013-2014 gas year, as Northern has Algonquin capacity on the Chicago path to consider for renewal. For the 2015-2016 gas year, Northern has more contract renewals to consider, its Tennessee Niagara and FS-MA storage capacity. The combined reduction of these resources cause the Design Winter Resource Balance to show modest deficiencies of resources in 2013-2014 and 2014-2015 gas years and more considerable deficiencies of resources in 2015-2016.

The Design Winter Resource Balance indicates Northern's need for additional resources in 2013-2014, which is earlier than the Design Year Resource Balance indicated a shortage. Please note that the initial Design Winter Resource Balance is calculated assuming supplies are not replaced as they terminate.

3. Potential Variability in the Resource Balance

For each of the Design Day, Year and Winter Resource Balance calculations provided in this Integrated Resource Plan, Northern has calculated both Base-, High- and Low-Case Demand Growth. Currently, the Demand Growth Case does not appear to the primary factor in the Resource Balance. The single largest factor affecting Northern's Resource Balance is the termination of supply resources, rather than demand growth case.

The Design Day, Design Winter and Design Year shortages observed in the initial Resource Balance are reflective of Northern's current peaking supply procurement process, under which Northern procures its peaking supplies year-to-year, rather than for long-term. Shorter-term procurement of peaking supplies allows Northern the flexibility on the supply-side resources side to address changes in requirements due to retail migration, rate of demand growth. Generally, peaking supplies are infrequently utilized for the provision of supplies. The purpose of peaking supply contracts is to ensure the provision of reliable service. By procuring peaking supplies year-to-year, Northern has the ability to best match its design day resource capabilities to its design day planning load requirement. Generally, delivered peaking supplies have relatively low fixed demand costs and relatively high variable supply costs, compared to non-peaking supplies, such as baseload or intermediate supply resources, which are backed by pipeline and storage capacity.

Northern believes that delivered peaking supplies will be available throughout the five-year planning horizon. This is based upon robust response to Northern's recently completed peaking service RFP combined with relatively low utilization of the PNGTS and Maritimes, which can feed both directly into Northern or the Tennessee Zone 6 (New England) markets.

The Design Year and Design Winter surpluses observed in the initial Design Year and Design Winter Resource Balances, reflect that Northern has ample pipeline and storage capacity under contract to meet planning load requirements on all but the very coldest of days during the current planning period. Northern has the flexibility to increase or decrease its non-peaking supply-side resources, in the event that planning load requirements grow at unexpected levels. If planning loads increase more than expected, Northern would respond, initially, by utilizing current resources at a higher load factor. If planning loads increase less than expected, Northern would respond, initially, by utilizing current resources at a lower load factor. When seeking supplies to fill its capacity resources, Northern seeks the flexibility from its suppliers to increase supplies at Northern's option on a daily and monthly basis in order to balance resources with requirements on a real-time basis.

Another option for maintaining balance between supply-side resources and planning load requirements is the release of excess capacity. Northern recently entered into releases of its under-utilized TETCO and Algonquin capacity contracts. These releases began in April 2009 and continue through October 2012[67]. Although these releases were for longer-terms (greater than one year), the

[67] These were the releases of Algonquin contract number 93201A1C and Texas Eastern contract number 800384.

company reserved the right to a single recall of this capacity in the event that Northern determined at a later date that the capacity was necessary and cost effective to meet planning load requirements. The decision to release these capacity contracts was in response to the fact that these contracts were not currently needed to supply the system, but were highly valued by the market place.

4. Implications of the Resource Balance for the lowest cost resource procurement

Clearly, the Design Day Resource Balance analysis indicates that under extreme cold circumstances, Northern has needs for additional supply resources after the 2011-2012 gas year, due to the capacity shortfalls beginning 2012-2013 without the addition of new resources. This is reflective of Northern's current process of procuring delivered peaking supplies on a year-to-year basis, rather than for longer terms. However, the Design Year and Design Winter Resource Balance surpluses even after 2011-2012 gas year indicate, subject to the limitations of these tests discussed above, that the system has ample resources to meet typical day requirements. The bulk of the Design Day Resource Balance shortage beginning the 2012-2013 gas year is due to the termination of approximately 32,000 Dth of Peaking Supply arrangements. Northern currently plans to seek replacement supplies on an annual basis. As Northern seeks additional capacity to fill the Design Day Resource Balance shortfall for this period, it will likely continue to supplement its portfolio with Peaking Supply contracts, since the need is only in the very coldest of winter days. Based on recent experience, delivered peaking supplies can typically be procured for a lower fixed cost than pipeline or underground storage resources.

D. Supply Resource Alternatives

This Integrated Resource Plan lays out Northern's process for identifying and evaluating alternatives to meeting the Company's Design Day and Design Winter planning criteria. The first step in this process is identifying supply alternatives, including both existing and new resources to be evaluated on equal footing.

Northern identifies its supply alternatives within its existing resources by periodically reviewing its contractual rights and confirming any renewal rights and provisions with the applicable counterparties. Northern identifies new supply alternatives by staying informed on developments within the natural gas market. In order to stay informed on both market and regulatory developments, Northern is a member of both the Northeast Gas Association ("NGA") and the American Gas Association ("AGA"). Northern also subscribes to natural gas market periodicals, such as Bentek and Platt's *Gas Daily*. Northern monitors Electronic Bulletin Board ("EBB") postings for additional information, which may affect the natural gas market. In addition, Northern maintains business relationships with pipelines serving the Northeast and commodity suppliers and attends the annual LDC Forum. These activities help Northern to stay informed of the potential new supplies that may become available and who the market players are that Northern may potentially contract with.

A summary of the existing and new potential supply resources is provided below.

1. Pending and Recent Contract Renewal Decisions

Northern has identified the following list of existing resources, which require contract decisions during the five-year planning period covered by this Integrated Resource Plan.

a) Chicago Capacity Path Contract Decisions

(1) Tennessee Contract 95196

Tennessee Contract 95196[68] (844 Dth into Granite and 1,382 Dth into Bay State Exchange) was set to terminate on 10/31/2012. Northern extended this agreement for 5 years to 10/31/2017.

(2) Algonquin Contract 93200F

Algonquin Contract 93200F (4,211 Dth into Bay State Exchange) was set to terminate on 10/31/2012. Northern extended this agreement for an additional year to 10/31/2013. This contract extends year-to-year, unless terminated upon one-year notice.

(3) Iroquois Contract R181001

Iroquois Contract R181001 (6,569 Dth connecting TransCanada and Tennessee portions of this path) was set to terminate 10/31/2013. This contract was extended until 10/31/2017.

(4) Vector Contracts FT-1-NUI-0122 and FT-1-NUIC0122

Vector Contracts FT-1-NUI-0122 and FT-1-NUIC0122 (6,070 Dth at the beginning of this path) terminate on 3/31/2016. Northern does not have rights to unilaterally extend this agreement but is evaluating whether to seek an extension of this agreement to 10/31/2017 in order to line up with the termination dates of the Union and TransCanada capacity in this path.

b) Tennessee Niagara Path Contract Decisions

(1) Tennessee Contract 46314

Tennessee Contract 46314 (950 Dth into Bay State Exchange) terminates on 3/31/2012. Northern has no extension rights to this capacity.

(2) Tennessee Contracts 5292

Tennessee Contracts 5292 (1,406 Dth into Bay State Exchange) and 39735 (929 Dth into Granite) each terminate on 3/31/2015. Northern may extend these agreements for 5 years to 3/31/2020.

[68] Effective September 1, 2011, Tennessee Contract No. 31861 was converted from NET-284 service to FT-A service under Tennessee's tariff. In order to effectuate this change, Tennessee Contract No. 95196 under Rate Schedule FT-A was entered to replace Tennessee Contract No. 31861 under Rate Schedule NET-284.

c) Tennessee Storage Contract Decisions

(1) Tennessee Contracts 5195

Tennessee Contracts 5195 (259,337 Dth of Tennessee Storage Space) and 5265 (2,653 Dth into Granite) were set to terminate 10/31/2013. Northern extended these agreements through 3/31/2015, as part of Northern's compliance with the settlement of Tennessee's FERC rate case, docketed as RP11-1566.

d) Peaking Supply Contract Decisions

(1) Peaking Supplies 1, 2 & 3

Peaking Supplies 1, 2 & 3 (collectively 32,000 Dth into Granite) each terminate after the 2011-12 Winter Season. Northern is assuming that similarly priced supplies will be available for each subsequent year of the planning period.

e) LNG Supply Contract Decisions

(1) LNG Contract

The current LNG Contract (up to 125,000 Dth of LNG per year) terminates 10/31/2012. Northern is assuming that a comparable supply is available for each subsequent year of the planning period.

f) Replacement of Delivered Supplies

(1) Delivered supplies

Delivered supplies comprise a portion of Northern's current supply portfolio. Rather than committing to pipeline and/or storage resources, Northern has entered into a number of contracts directly with wholesale suppliers, which provide supplies delivered either to a Granite receipt point or a Northern city-gate meter. Northern's current practice is to replace these supplies on an annual basis, as needed.

(2) Peaking Supplies 1, 2 & 3

Peaking Supplies 1, 2 & 3 (collectively 32,000 Dth into Granite) each terminate after the 2011-12 Winter Season. Northern is assuming that comparable supplies will be available for each subsequent year of the planning period.

(3) Lewiston Baseload

Lewiston Baseload: The Baseload Supply of 5,500 Dth per day for November 2011 through March 2012 has no renewal provisions. Northern is assuming that Lewiston Baseload supply is available under comparable terms.

g) Algonquin & Texas Eastern Capacity Path Contract Decisions

(1) Algonquin Contract 93201A1C

Algonquin Contract 93201A1C (1,251 Dth into Bay State Exchange) terminates 10/31/2013. This contract extends year-to-year, unless terminated upon one-year notice.

(2) Texas Eastern Capacity

Texas Eastern Capacity: Northern has given five years notice to terminate all of its Texas Eastern capacity.

2. New Potential Supply Resources

Below is a list of the new potential supply resources, which Northern considers most likely to be viable alternatives to serving Northern's markets in New Hampshire and Maine. A more complete list of Northeast projects is provided in Appendix VI-1A, which is the NGA's Planned Enhancements, Northeast Natural Gas Pipeline Systems, which was last updated May 2, 2011.

a) Supply Sources off Maritimes

In order to access the following resources that are available via the Maritimes pipeline, Northern would either buy delivered supply from a third party that holds Maritimes capacity or contract with Maritimes for its own capacity.

(1) Repsol Canaport LNG

Canaport LNG is a state-of-the-art liquefied natural gas (LNG) receiving and regasification terminal in Saint John, New Brunswick. Canaport LNG has the ability to sendout a maximum 1.2 BCF per day and the ability to store up to 10 BCF of LNG. Canaport LNG began operations in June of 2009. Canaport LNG is connected to the Brunswick Pipeline, which has a capacity of 850,000 Dth per day and connects to the Maritimes & Northeast U.S. Pipeline. Repsol Energy has contracted for 100% of the Canaport LNG storage capacity and 100% of the Brunswick Pipeline capacity. Repsol has contracted for 730,000 Dth of capacity on Maritimes & Northeast U.S. Pipeline. Repsol has extensive LNG supplies throughout the world and extensive abilities to ship LNG. Northern currently takes advantage of supplies sourced from the Canaport LNG terminal by purchasing delivered supply from Repsol Energy.

(2) Sable Island

The Canada-Nova Scotia Offshore Petroleum Board website (www.cnsopb.ns.ca) provides the following description of the Sable Island natural gas resource:

The Sable Offshore Energy Project (SOEP) involves the development of five natural gas fields near Sable Island which is located approximately 225 km off the east coast of Nova Scotia. The six fields are: Venture, South Venture, Thebaud, North Triumph, Glenelg and Alma. Together, these fields contain an estimated 85 billion cubic metres (3 TCF) of recoverable gas reserves and 11.9 million cubic metres

(74.8 MMbbl) of condensate. SOEP is operated by ExxonMobil Canada Ltd. with its partners Shell Canada Limited, Imperial Oil Resources Limited, Pengrowth Corporation, and Mosbacher Operating Ltd.

Sable Island natural gas supplies access the Maritimes & Northeast Pipeline at the Goldboro Gas Processing Plant. Via the Maritimes & Northeast Pipeline, this supply can potentially reach Northern's markets. According to the Sable Offshore Energy Project website, www.soep.com, the 2010 natural gas production of the Sable Island Offshore Energy Project averaged 0.3 BCF daily.

(3) Deep Panuke

According to the Encana web site, www.encana.com, Deep Panuke is an offshore drilling project located 155 miles southeast of Nova Scotia that is owned by Encana Energy. Natural gas from Deep Panuke will be processed offshore and transported, via subsea pipeline, to Goldboro, Nova Scotia for further transport to market via the Maritimes & Northeast Pipeline. First gas is expected from Deep Panuke in 2012. According to the Nova Scotia web site, www.gov.ns.ca, production from Deep Panuke is expected to be about 0.3 BCF/day and the recoverable gas supply is estimated to be 632 BCF. Encana has made arrangements for Repsol Energy to market the Deep Panuke output, when commercial production begins.

(4) Supply Sources off Tennessee

Northern holds Tennessee Pipeline capacity, and the following are sources of supply that Northern can buy to fill that capacity.

(5) GDF Suez Neptune LNG, Everett LNG

According to the GDF Suez website, www.suezenergyna.com, Neptune LNG LLC, an affiliate of GDF Suez, operates an LNG facility approximately 10 miles off the coast of Gloucester, Massachusetts, delivers and average of 0.4 BCF per day and is capable of delivering up to 0.75 BCF per day of natural gas supply into the New England region. Distrigas of Massachusetts LLC ("DOMAC"), another GDF Suez affiliate, owns and operates an LNG import and regasification facility located along the Mystic River in Everett, Massachusetts (the "Everett Marine Terminal"). The Everett Marine Terminal is capable of storing of 3.4 billion cubic feet of LNG. The Terminal's installed vaporization capacity (nameplate) is approximately one billion cubic feet per day, with a sustainable daily throughput capacity of approximately 715 million cubic feet per day.

GDF Suez sells vapor product as Tennessee Zone 6 and Algonquin delivered gas and liquid product out the Everett Marine Terminal. GDF Suez is a major player in the New England LNG market, and has been Northern's LNG supplier for the Lewiston Maine LNG facility for many years. Since GDF Suez facilities are downstream of Tennessee's pipeline restriction points, Northern assumes that this potential new supply resource could be a source of incremental capacity to the interconnection between Tennessee and Granite in Haverhill, Massachusetts.

(6) Marcellus Shale

As found on the Energy Information Administration's website, www.eia.gov, Marcellus shale gas play is located across 95,000 square miles in the Appalachian Basin covering portions of the States of Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. Most of the active development is in a 10,000 square mile area in the states of Pennsylvania and West Virginia. Undeveloped, technically recoverable Marcellus shale gas is estimated to be 410 TCF[69] out of a total U.S. natural gas resource base of 2,543 TCF.[70] "Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas." Recovery of this Marcellus shale natural gas requires the use of horizontal drilling and hydraulic fracturing technologies.[71] As of March 2011, production of Marcellus shale had grown to 3 BCF per day.

Marcellus production can access Tennessee Gas Pipeline in Tennessee Zone 4, 300 Leg. Northern's current transportation capacity is considered "out of path" with the Marcellus production. In response to the significant increase in production in this part of the Tennessee system, Tennessee has committed to the Northeast Upgrade Project, which is provide an incremental 636,000 Dth of capacity to move Marcellus shale gas to New Jersey markets. Two major producers in Marcellus, Chesapeake Energy and StatOil, have contracted for 100% of the capacity of this project. Additionally, Tennessee had issued a non-binding open season for its proposed Northeast Exchange Project. This project, if built, will create 600,000 Dth of capacity from Marcellus production to Wright, NY. Northern has participated in this open season process, in order to explore the possibility of combining Northern's Tennessee contracts with Wright, NY receipt points (Contracts 95196 and 41099) with capacity procured through this process. Under the open season, Northern could contract for approximately 6,000 Dth of Tennessee capacity from Marcellus to Tennessee Zone 6.

Northern currently takes advantage of the Marcellus supply by purchasing directly from Marcellus producers. These producers have used their own Tennessee capacity in order to ship gas from their well-heads to points "in path" for Northern's capacity contracts on Tennessee.

(7) Rockies Express

Rockies Express ("REX") is a major pipeline, stretching from Northwestern Colorado to Clarington, OH, which began commercial operation in November 2009. Since the Clarington, OH interconnection with Tennessee is "in path" of Northern's existing long-haul capacity contract, Northern has been able to take advantage of less expensive supply delivered into Tennessee off of REX. Since REX is upstream of Tennessee's pipeline restriction points, Northern assumes that at this time, Northern would be unable to purchase additional Tennessee capacity from REX to the interconnection between Tennessee and Granite in Haverhill, Massachusetts. However, Clarington, OH on Tennessee is "in path"

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[69] Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, U.S. Energy Information Administration, Page 5.
[70] http://www.eia.gov/analysis/studies/worldshalegas/
[71] http://www.eia.gov/naturalgas/

of Northern's existing long-haul capacity contract, so Northern has been able to take advantage of less expensive supply delivered into Tennessee off of Rockies Express.

b) Supply Sources off PNGTS

Although Portland Natural Gas Transmission System ("PNGTS") has been in operation since March 1999, there is significant available capacity on this system, which could be purchased as incremental capacity to serve Northern customers. As discussed in the review of Northern's existing portfolio, supply on PNGTS can be sourced, either from the interconnection between PNGTS and Maritimes & Northeast Pipeline at Westbrook, ME or from the interconnection between PNGTS and TransQuebec and Maritimes Pipeline ("TQM") near Pittsburgh, NH[72]. The supply options off of the Maritimes & Northeast Pipeline are discussed extensively in the part a) of this section. Currently, TQM capacity is contracted by TransCanada and the cost of this pipeline is rolled into TransCanada Mainline rates.[73] This is the arrangement, utilized by TransCanada to provide the capacity, contracted by Northern from Dawn to East Hereford (the TQM side of the interconnection between PNGTS and TQM).

There is ample available capacity on both the PNGTS and TQM sides of the interconnection. Long-term contracts on PNGTS total only 150,200 Dth out of the 217,000 Dth of available capacity.[74] As of November 2011, long-term contracts on TransCanada for delivery to the East Hereford meter totaled 52,753 GJ. A major decontracting of capacity to East Hereford occurred in November 2008. Prior to November 2008, TransCanada had contracted for a total of 211,027 GJ of capacity contracts to the East Hereford meter.[75] Although the PNGTS and TQM infrastructure have existed for some time now, there is abundant available capacity, which would potentially be available as either replacement capacity or new capacity to meet projected growth in planning load demand.

However, incremental PNGTS and TransCanada capacity are not attractively priced. Both PNGTS and TransCanada are engaged in contentious rate cases, due to the high costs of the capacity on their respective systems. The high rates charged by these pipelines are caused in part by the decrease in Western Canadian Sedimentary Basin ("WCSB") production, which has reduced the throughput of these pipelines. This decrease is due to a number of factors, including natural declines in Western Canadian production due to well maturity, construction of competing pipelines taking Western Canadian production into Western Canada and Western U.S. markets, and the advent of Marcellus Shale

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[72] Both PNGTS and TQM are affiliates of TransCanada.

[73] In TCPL's Tolls Application for 2012 and 2013, TCPL proposes to directly allocate TQM costs to contracts, which utilize the TQM facilities. Currently, the cost of TQM capacity is included in TCPL system costs and is allocated to all contracts, across the TCPL system. If approved by the NEB, this could substantially increase the cost of capacity to serve exports from Canada through East Hereford. Northern is pursuing this issue at the NEB through its membership in Alberta Northeast ("ANE").

[74] The level of PNGTS' capacity is currently under dispute. The PNGTS Electronic Bulletin Board ("EBB") indicates that the total PNGTS capacity is only 168,672 Dth, however Northern is currently engaged in litigation against PNGTS under FERC Dockets RP08-306 and RP10-729. In each of these rate cases, the matter of PNGTS' system capacity is an issue that Northern, through the Portland Shipper's Group ("PSG"), is contesting. The FERC's order in RP08-306 states capacity as 210,840 Dth. The Initial Decision in RP10-729, issued December 8, 2011, states capacity is 168,000 Dth. PSG contends that the available capacity on the PNGTS system should be 217,000 Dth.

[75] This information was gathered from TransCanada's monthly Contract Demand Energy report.

production, significantly reducing reliance on Western Canadian supply by Eastern Canadian and U.S. markets. For these reasons, the economics of additional PNGTS supply, sourced from TransCanada, are not currently favorable.

The major supply options on TransCanada include either WCSB supplies or Dawn, Ontario hub supplies. The WCSB, as discussed above, currently faces the challenge of declining overall production and competing demands in Western Canada and the US. Dawn, Ontario is a major North American hub, which is interconnected with ten major pipelines as well as major underground storage facilities.[76]

E. Resource Optimization Analysis

Northern determined its preferred supply portfolio for the five-year planning period covered in this Integrated Resource Plan (2011-2012 through 2015-2016) based upon the Base, High, and Low Demand Cases prepared for this Integrated Resource Plan, Northern's current natural gas supply contractual commitments, alternative new supply sources, current pipeline and storage fixed demand rates, variable commodity rates and variable fuel rates, current NYMEX natural gas contract settlement prices (as of August 18, 2011), the Company's forecast of basis pricing, which is the spread between actual supply prices and NYMEX contract prices, and current underground storage and supply constraints. Initially, Northern utilized Sendout® natural gas supply resource optimization model in order to perform the resource optimization analysis for each of seven demand scenarios. The results from each demand scenario were then tabulated and summarized, as Sendout® determined the optimal supply portfolio for each. Then, Northern consolidated and interpreted these results for the purpose of determining a single preferred portfolio over the planning period. An overview of the Resource Optimization Analysis process and a presentation of the results follow.

1. Sendout® Modeling

The Sendout® model is designed to determine the optimal mix of resources based upon forecast customer demand, fixed demand supply and transportation prices, variable supply and transportation prices. Sendout® calculates the best cost outcome for the given resources, customer demand and prices. In its default setting, Sendout® optimizes variable costs only. Certain resources can be designated as "resource mix," allowing Sendout® to determine whether the designated resource should be renewed, considering both fixed demand and variable costs.

a) Demand Scenarios

As discussed above, the Company evaluated its portfolio and supply contracting options under seven demand scenarios, which are listed below:

[76] http://www.uniongas.com/storagetransportation/resources/dawn/

(1) Base Case Design Weather Scenario

(2) Base Case Normal Weather Scenario

(3) High Case Design Weather Scenario

(4) High Case Normal Weather Scenario

(5) Low Case Design Weather Scenario

(6) Low Case Normal Weather Scenario

(7) Base Case Design Weather Scenario with Cold Snap

The development these demand scenarios is discussed in Section IV of this Integrated Resource Plan.

a) Price Forecast

For the purposes of this Resource Optimization Analysis, Northern utilized the following assumptions.

(1) NYMEX Natural Gas Settlement Prices

NYMEX Natural Gas Settlement Prices as of August 18, 2011 were used in the resource optimization analysis.

(2) Monthly Index Prices

Monthly Index Prices were forecast based on 12 months of historic data. Northern calculated for each month, August 2010 through July 2011, the spread between each applicable Monthly Index Price and the monthly NYMEX final settlement price. The price forecast assumes that these spreads will remain constant throughout the five-year planning period.

(3) Pipeline and Storage Rates

Pipeline and Storage Rates are presumed to be static throughout the five-year planning period and are based on the latest filed rates, available on August 18, 2011. Please note that the filing does not reflect the Tennessee rate case settlement, approved in FERC Docket No. RP11-1566, nor does it reflect the TransCanada Tolls Application for 2012 and 2013, filed on September 1, 2011.

b) Northern's Current Portfolio Commitments

The Resource Optimization Analysis reflects Northern's capacity commitments through the five-year planning period. However, if Northern has the option to renew or terminate a capacity contract, the Resource Optimization Analysis determines for each scenario the optimal maximum daily quantity to renew the capacity contract for. Please note that in making actual contract renewal decisions, Northern likely does not have the ability to reduce capacity levels associated with individual contracts without risk of losing all the capacity of the contract. The Sendout® model may recommend renewing a particular contract at a reduced volume. However, Northern typically must either renew the contract in its entirety or terminate it completely. Northern's current portfolio commitments are summarized in Appendix VI-1. Northern's upcoming contract renewal or termination decisions are summarized in Section VI.D.1, "Pending and Recent Contract Renewal Decisions".

c) Alternative New Supply Sources

Before running Sendout®, as part of the Resource Optimization Analysis, Northern, first, determined what new resources to offer the Sendout® resource optimization model to compete with Northern's existing resources up for renewal. The purpose of this step is to streamline the resource optimization process. Resources that are clearly too expensive relative to other alternatives are ruled out before running Sendout®. Northern considered the following sources of incremental capacity to compete with renewal of Northern's existing capacity.

(1) Tennessee Zone 6 Delivered Supply

Based upon the general availability of supply in Tennessee Zone 6, it is assumed that adequate volumes of delivered supply would exist to replace any of the capacity contracts up for renewal in the current planning period.

(2) TransCanada Dawn Supply

Based upon the general availability of capacity on both the TransCanada and PNGTS pipelines, it is assumed that capacity from Dawn to Northern's facilities could be purchased in adequate amounts to replace any of the capacity contracts up for renewal in the current planning period.

(3) TransCanada WCSB Supply

Based upon the general availability of capacity on both the TransCanada and PNGTS pipelines, it is assumed that capacity from Western Canada to Northern's facilities could be purchased in adequate amounts to replace any of the capacity contracts up for renewal in the current planning period.

(4) Renewal of Algonquin Contract 93201A1C

Renewal of Algonquin Contract 93201A1C (1,251 Dth into Bay State Exchange) (Please note that at the time this analysis was conducted, the Algonquin Contract 93201A1C had not yet been renewed.)

Incremental capacity on Tennessee upstream of Tennessee Zone 6 could not be considered in this Integrated Resource Plan because no such capacity is available to be purchased at the current time. Supplies delivered off of Maritimes were considered to be on average $0.25 per Dth higher than Tennessee Zone 6 Delivered Supply prices. Although it may be possible to purchase Maritimes Northeast U.S. pipeline capacity, it is unclear whether the price of supply to fill this capacity at the inlet to MN U.S. at Baileyville, Maine would be substantially different from the price of supply delivered to Northern's city-gate on MN U.S. at Lewiston, Maine.

The Company calculated the projected delivered price, including both fixed and variable supply and variable transport costs, for each alternative new supply source as both a twelve- and five-month baseload supply resources, based upon the price forecast assumptions, discussed above. These calculations can be found in Appendix VI-5 and are summarized below in Table VI-5.

Table VI-5: Projected Alternative New Supply Costs per Dth

Table VI-5. Projected Alternative New Supply Costs per Dth		
Alternative New Supply	12-Months	5-Months
Tennessee Zone 6 Delivered	$ 5.37	$ 6.15
TransCanada Dawn Supply	$ 7.30	$ 10.83
TransCanada Empress Supply	$ 8.79	$ 15.01
Algonquin 1,251 Dth Capacity	$ 5.38	$ 6.24

Monthly commodity prices were based on the August 18, 2011 NYMEX settlement prices for the period beginning November 2011 through October 2012 and the average monthly spread between the applicable monthly index price and NYMEX for the twelve month period beginning August 2010 through July 2011. Pipeline fixed demand and variable transport rates from the supply source to a Granite receipt meter were based on TransCanada's latest available approved rates as of August 18, 2011. Please note that rates on TransCanada filed for new rates since the time this analysis was originally prepared. Based on this analysis, the lowest cost alternative new supply to compete with existing resources are Tennessee Zone 6 Delivered Supplies. As such, Northern modeled replacement of existing resources with incremental Tennessee Zone 6 Delivered Supplies. The demand costs for incremental supplies transported on TransCanada and PNGTS into Granite are expected to be too high to be selected by the model.

d) Chicago Path and Washington 10 Path Capacity Optimization

Referring to the Chicago Path Capacity Diagram and Details, provided in Appendix VI-1, one aspect of this supply resource, which Northern considered in preparation of this Integrated Resource Plan, is that there are several supply options associated with this particular path of capacity. Typically, Northern utilizes its Chicago Path capacity by purchasing supplies, based on Chicago city-gate prices. For resource planning purposes, Northern also considered purchasing supplies all along this capacity path. Specifically, Northern considered four different supply options, including Chicago city-gate, Dawn, Iroquois Receipts and Tennessee Wright. Adding alternative supply options to the modeling of the Chicago path allowed Sendout® to consider the economics of renewing Iroquois and Vector based on the availability of other options for sourcing gas supply with this capacity path.

Currently, Northern's Washington 10 storage inventory is the sole supply shipped on Northern's Washington 10 Path to Northern's city-gates. In the Resource Optimization Analysis, Northern allowed Sendout® to also consider purchases on PNGTS or purchases of Chicago city-gate supplies, as an alternative to Washington 10 inventory. By modeling the Washington 10 capacity path to allow alternative supplies, Northern has developed a model to further improve its evaluation of future asset management contracts, which may offer alternative means of filling the Washington 10 capacity path.. The Company is using this Integrated Resource Plan as an opportunity to consider alternative uses of its current portfolio, as well as the planning of the portfolio, itself.

e) Sendout Results

Northern has prepared a common set of reports for each of the seven (7) Demand Scenarios that were discussed in Section VI.D.1.a, based upon its Sendout® results, which are provided in Appendix VI-6, Appendix VI-7, Appendix VI-8 and Appendix VI-9. Appendix VI-6 reports estimated Delivered City-Gate Commodity Costs. Appendix VI-7 provides Delivered City-Gate Total Costs and Volumes. Appendix VI-8 provides Load Duration Curves and Appendix VI-9 provides a Cold Snap Analysis. The Delivered City-Gate Commodity Cost reports provide variable supply and transportation costs by supply source. The Delivered City-Gate Total Costs and Volumes schedules provide total delivered costs, inclusive of both fixed and variable supply and transportation costs, and supply volumes by source. The Load Duration Curves rank each day of the winter period from highest planning load requirement to lowest, providing a graphical depiction of how the planning load is served with the resources in the portfolio. The Cold Snap Analysis provides, in graphical format, how the planning load is served during a 7-day Cold Snap scenario in each of year of the planning period.

The tables and charts that follow mirror in summary fashion the materials provided in Appendix VI, including the use of common labels (for example Table VI-6(4) is a summary of Appendix VI-6(4)).

(1) Delivered City-Gate Commodity Costs by Supply Source

Delivered City-Gate Commodity Costs by Supply Source are detailed in Appendix VI-6, which includes a set of 15-page subsections for each of the seven demand scenarios. Each 15-page subsection includes three pages for each year of the five-year planning period. Page 1 provides Delivered City-Gate Commodity Costs by Supply Source. Page 2 provides Delivered City-Gate Commodity Volumes by Supply Source, and Page 3 provides Delivered Commodity Cost per Dth by Supply Source. These costs include variable supply and transportation costs only and do not include any fixed demand costs. The tables below provide summary data for the five-year planning period for each scenario. In the tables, the five-year summary data are ranked from least expensive to most delivered cost per Dth.

Table VI-6(1): Base Case Design Weather Commodity Costs

Table VI-6(1) Base Case Design Weather Scenario Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,814,385	4,830,066	$5.345
Tennessee Production Path Total	$109,623,398	20,107,848	$5.452
Chicago Path Total	$30,350,814	5,278,089	$5.750
W10 Path Total	$105,088,354	17,468,357	$6.016
Niagara Path Total	$8,319,241	1,371,232	$6.067
New Lewiston Supplies Total	$16,157,447	2,303,736	$7.014
New TGP Zone 6 Supplies Total	$30,648,091	4,348,800	$7.047
PNGTS Path Total	$3,678,151	518,648	$7.092
LNG Plant Total	$5,732,107	652,310	$8.787
Peaking Supply Total	$3,276,996	233,495	$14.035
Total System	$338,688,984	57,112,579	$5.930

Table VI-6(2): Base Case Normal Weather Commodity Costs

Table VI-6(2) Base Case Normal Weather Scenario Estimated Delivered City-Gate Variable Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,805,011	4,827,885	$5.345
Tennessee Production Path Total	$109,371,663	20,060,741	$5.452
Chicago Path Total	$22,252,062	3,881,403	$5.733
W10 Path Total	$98,513,965	16,445,383	$5.990
Niagara Path Total	$7,286,703	1,179,296	$6.179
New Lewiston Supplies Total	$10,728,542	1,611,136	$6.659
PNGTS Path Total	$2,696,178	400,771	$6.727
New TGP Zone 6 Supplies Total	$24,752,906	3,627,149	$6.824
LNG Plant Total	$2,219,588	262,614	$8.452
Peaking Supply Total	$496,158	34,562	$14.356
Total System	$304,122,776	52,330,940	$5.812

Table VI-6(3): High Case Design Weather Commodity Costs

Table VI-6(3) High Case Design Weather Scenario Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,814,385	4,830,066	$5.345
Tennessee Production Path Total	$111,303,803	20,409,040	$5.454
Chicago Path Total	$31,118,427	5,416,046	$5.746
W10 Path Total	$108,474,250	17,942,667	$6.046
Niagara Path Total	$8,633,600	1,426,521	$6.052
New TGP Zone 6 Supplies Total	$32,962,616	4,684,072	$7.037
New Lewiston Supplies Total	$17,872,096	2,511,942	$7.115
PNGTS Path Total	$3,985,839	557,977	$7.143
LNG Plant Total	$7,207,268	807,139	$8.929
Peaking Supply Total	$5,053,581	354,288	$14.264
Total System	$352,425,864	58,939,758	$5.979

Table VI-6(4): High Case Normal Weather Commodity Costs

Table VI-6(4) High Case Normal Weather Scenario Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,805,895	4,828,091	$5.345
Tennessee Production Path Total	$111,034,257	20,358,508	$5.454
Chicago Path Total	$26,568,709	4,616,576	$5.755
W10 Path Total	$99,978,101	16,668,508	$5.998
Niagara Path Total	$7,421,058	1,203,752	$6.165
New Lewiston Supplies Total	$11,750,765	1,749,905	$6.715
PNGTS Path Total	$2,903,930	426,555	$6.808
New TGP Zone 6 Supplies Total	$26,445,486	3,850,848	$6.867
LNG Plant Total	$2,523,127	294,886	$8.556
Peaking Supply Total	$899,245	61,898	$14.528
Total System	$315,330,573	54,059,526	$5.833

Table VI-6(5): Low Case Design Weather Commodity Costs

Table VI-6(5) Low Case Design Weather Scenario Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,814,385	4,830,066	$5.345
Tennessee Production Path Total	$107,896,118	19,798,079	$5.450
Chicago Path Total	$27,753,778	4,866,947	$5.703
W10 Path Total	$102,573,313	17,114,222	$5.993
Niagara Path Total	$8,065,080	1,325,790	$6.083
New Lewiston Supplies Total	$14,713,534	2,127,420	$6.916
PNGTS Path Total	$3,439,564	487,917	$7.049
New TGP Zone 6 Supplies Total	$28,705,285	4,064,306	$7.063
LNG Plant Total	$4,674,368	540,822	$8.643
Peaking Supply Total	$2,525,024	181,306	$13.927
Total System	$326,160,449	55,336,875	$5.894

Table VI-6(6): Low Case Normal Weather Commodity Costs

Table VI-6(6) Low Case Normal Weather Scenario Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,804,127	4,827,679	$5.345
Tennessee Production Path Total	$107,475,909	19,719,440	$5.450
Chicago Path Total	$19,530,374	3,417,295	$5.715
W10 Path Total	$97,840,934	16,332,356	$5.991
Niagara Path Total	$7,094,574	1,144,767	$6.197
New Lewiston Supplies Total	$8,638,494	1,314,542	$6.571
PNGTS Path Total	$2,244,288	337,261	$6.654
New TGP Zone 6 Supplies Total	$22,459,681	3,319,895	$6.765
LNG Plant Total	$1,853,914	224,106	$8.272
Peaking Supply Total	$202,165	14,524	$13.919
Total System	$293,144,459	50,651,865	$5.787

Table VI-6(7): Base Case Weather with Cold Snap Commodity Cost

Table VI-6(7) Base Case Design Weather Scenario with Cold Snap Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Commodity Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$25,814,385	4,830,066	$5.345
Tennessee Production Path Total	$109,554,236	20,094,870	$5.452
Chicago Path Total	$30,235,992	5,254,947	$5.754
W10 Path Total	$104,704,508	17,419,706	$6.011
Niagara Path Total	$8,216,930	1,350,848	$6.083
New Lewiston Supplies Total	$15,642,902	2,246,766	$6.962
PNGTS Path Total	$3,460,187	494,476	$6.998
New TGP Zone 6 Supplies Total	$30,063,814	4,282,247	$7.021
LNG Plant Total	$4,439,398	519,380	$8.547
Peaking Supply Total	$9,006,954	619,273	$14.544
Total System	$341,139,306	57,112,579	$5.973

In summary, under all scenarios, Tennessee Storage and Tennessee Production capacity paths provide access to the lowest delivered city-gate cost supplies. Please note that the Tennessee rate case settlement provides for increased variable transportation charges, which were not reflected in the Resource Optimization analysis. These resources are generally utilized by Northern all year long, due to the relatively low delivered cost. Next, Chicago, Washington 10, Niagara, Lewiston, PNGTS and TGP Zone 6 resources provide intermediate supplies, high utilization in the winter months and low utilization in the summer months. These intermediate supplies have somewhat higher commodity costs than the Tennessee supplies. Finally, the LNG plant and peaking supplies provide peaking resources provide supply on the coldest of winter days, due to the highest average cost supply on the system.

(2) Estimated Delivered City-Gate Total Costs and Volumes

Northern must consider both fixed and variable costs when making long-term resource decisions. Appendix VI-7 provides a summary for each of the seven demand scenarios of the total delivered costs, inclusive of both fixed demand costs and variable supply costs. Appendix VI-7 is organized as 6 pages for each demand scenario. Page 1 provides summary data over the entire five-year planning period. Each subsequent page provides summary data by year. On each page of Appendix VI-7, there are four sections. The top section provides total costs by supply source. The next section provides the variable commodity costs by supply source. The third section down provides non-Granite demand costs by supply source. The bottom section provides Granite Demand Costs by supply source.[77] For each section, the delivered city-gate volume and delivered cost per Dth are also provided. On each page, each supply source is ranked by total delivered city-gate cost per Dth. The tables below correspond to the seven demand scenarios in Appendix VI-7, with each providing a summary of the total delivered costs over the five year planning period.

Table VI-7(1): Base Case Design Weather Total Costs

Table VI-7(1)
Base Case Design Weather Scenario
Estimated Delivered City-Gate Total Costs and Volumes
November 2011 through October 2016

Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,257,327	4,830,066	$6.264
Tennessee Production Path Total	$140,797,184	20,107,848	$7.002
New Lewiston Supplies Total	$16,157,447	2,303,736	$7.014
New TGP Zone 6 Supplies Total	$32,108,244	4,348,800	$7.383
Niagara Path Total	$10,351,399	1,371,232	$7.549
Chicago Path Total	$48,928,159	5,278,089	$9.270
LNG Plant Total	$7,678,776	652,310	$11.772
PNGTS Path Total	$6,514,289	518,648	$12.560
Peaking Supply Total	$3,503,745	233,495	$15.006
W10 Path Total	$270,677,149	17,468,357	$15.495
Total System	$566,973,719	57,112,579	$9.927

[77] Because Northern's Granite capacity is not allocated to any single capacity path, the costs were allocated by simply dividing total Granite costs by the total system deliveries and allocating on the basis of delivered city-gate volumes by supply path. In the case of supply sources that do not utilize Granite capacity (Lewiston and the LNG Plant), no Granite costs were allocated.

Table VI-7(2): Base Case Normal Weather Total Costs

Table VI-7(2) Base Case Normal Weather Scenario Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,370,171	4,827,885	$6.291
New Lewiston Supplies Total	$10,728,542	1,611,136	$6.659
Tennessee Production Path Total	$141,039,939	20,060,741	$7.031
New TGP Zone 6 Supplies Total	$26,053,229	3,627,149	$7.183
Niagara Path Total	$9,278,308	1,179,296	$7.868
Chicago Path Total	$39,219,263	3,881,403	$10.104
LNG Plant Total	$3,152,050	262,614	$12.003
PNGTS Path Total	$5,503,454	400,771	$13.732
W10 Path Total	$264,170,607	16,445,383	$16.064
Peaking Supply Total	$644,002	34,562	$18.633
Total System	$530,159,565	52,330,940	$10.131

Table VI-7(3): High Case Design Weather Total Costs

Table VI-7(3) High Case Design Weather Scenario Estimated Delivered City-Gate Total Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,214,996	4,830,066	$6.256
Tennessee Production Path Total	$142,399,899	20,409,040	$6.977
New Lewiston Supplies Total	$17,872,096	2,511,942	$7.115
New TGP Zone 6 Supplies Total	$34,484,320	4,684,072	$7.362
Niagara Path Total	$10,671,326	1,426,521	$7.481
Chicago Path Total	$49,695,227	5,416,046	$9.176
LNG Plant Total	$9,616,876	807,139	$11.915
PNGTS Path Total	$6,830,446	557,977	$12.241
Peaking Supply Total	$5,338,312	354,288	$15.068
W10 Path Total	$274,069,497	17,942,667	$15.275
Total System	$581,192,996	58,939,758	$9.861

Table VI-7(4): High Case Normal Weather Total Costs

Table VI-7(4)
High Case Normal Weather Scenario
Estimated Delivered City-Gate Total Costs and Volumes
November 2011 through October 2016

Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,319,729	4,828,091	$6.280
New Lewiston Supplies Total	$11,750,765	1,749,905	$6.715
Tennessee Production Path Total	$142,592,755	20,358,508	$7.004
New TGP Zone 6 Supplies Total	$27,773,869	3,850,848	$7.212
Niagara Path Total	$9,407,401	1,203,752	$7.815
Chicago Path Total	$44,519,283	4,616,576	$9.643
LNG Plant Total	$3,534,145	294,886	$11.985
PNGTS Path Total	$5,716,266	426,555	$13.401
W10 Path Total	$265,543,318	16,668,508	$15.931
Peaking Supply Total	$1,056,220	61,898	$17.064
Total System	$542,213,751	54,059,526	$10.030

Table VI-7(5): Low Case Design Weather Total Costs

Table VI-7(5)
Low Case Design Weather Scenario
Estimated Delivered City-Gate Total Costs and Volumes
November 2011 through October 2016

Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,303,137	4,830,066	$6.274
New Lewiston Supplies Total	$14,713,534	2,127,420	$6.916
Tennessee Production Path Total	$139,152,891	19,798,079	$7.029
New TGP Zone 6 Supplies Total	$30,117,658	4,064,306	$7.410
Niagara Path Total	$10,095,041	1,325,790	$7.614
Chicago Path Total	$45,781,280	4,866,947	$9.407
LNG Plant Total	$6,287,688	540,822	$11.626
PNGTS Path Total	$6,269,796	487,917	$12.850
Peaking Supply Total	$2,726,753	181,306	$15.040
W10 Path Total	$268,199,782	17,114,222	$15.671
Total System	$553,647,560	55,336,875	$10.005

Table VI-7(6): Low Case Normal Weather Total Costs

Table VI-7(6) Low Case Normal Weather Scenario Estimated Delivered City-Gate Total Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,416,714	4,827,679	$6.300
New Lewiston Supplies Total	$8,638,494	1,314,542	$6.571
Tennessee Production Path Total	$139,214,367	19,719,440	$7.060
New TGP Zone 6 Supplies Total	$23,689,714	3,319,895	$7.136
Niagara Path Total	$9,085,783	1,144,767	$7.937
Chicago Path Total	$35,900,937	3,417,295	$10.506
LNG Plant Total	$2,690,084	224,106	$12.004
PNGTS Path Total	$5,031,492	337,261	$14.919
W10 Path Total	$263,612,260	16,332,356	$16.140
Peaking Supply Total	$342,861	14,524	$23.607
Total System	$518,622,707	50,651,865	$10.239

Table VI-7(7): Base Case Design Weather Total Costs

Table VI-7(7) Base Case Design Weather Scenario with Cold Snap Estimated Delivered City-Gate Total Costs and Volumes November 2011 through October 2016			
Supply Source	Delivered City-Gate Total Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage Path Total	$30,251,747	4,830,066	$6.263
New Lewiston Supplies Total	$15,642,902	2,246,766	$6.962
Tennessee Production Path Total	$140,700,291	20,094,870	$7.002
New TGP Zone 6 Supplies Total	$31,495,258	4,282,247	$7.355
Niagara Path Total	$10,239,837	1,350,848	$7.580
Chicago Path Total	$48,798,856	5,254,947	$9.286
LNG Plant Total	$5,992,343	519,380	$11.537
PNGTS Path Total	$6,287,678	494,476	$12.716
Peaking Supply Total	$9,438,960	619,273	$15.242
W10 Path Total	$270,257,010	17,419,706	$15.514
Total System	$569,104,883	57,112,579	$9.965

In summary, Tennessee Storage provides Northern the lowest overall delivered cost of all the supply options in the portfolio. Tennessee Zone 4 supply prices are relatively inexpensive due to the presence of Marcellus Shale and the interconnection of REX pipeline and Tennessee within this area. Further, Tennessee demand costs are low relative to the other pipelines that can serve New England markets. The Washington 10 capacity path is consistently one of the most expensive resources on a total cost basis. This is primarily due to the very high demand rates on TransCanada and PNGTS. Due to Northern's existing contract commitment to this supply resource for the duration of the planning period, Northern has been active in participating in the rate proceedings for both PNGTS and TransCanada for the purpose of achieving lower demand rates for the benefit of Northern's planning load customers.

(3) Load Duration Curve for each winter of the five-year planning period.

In Appendix VI-8, system Planning Load is ranked from highest to lowest and system dispatch is provided in graphical form for each winter of the five-year planning period. The figures below provide the 2011-2012 Load Duration Curve for each scenario.

Figure VI-8(1): Base Case Design Weather Load Duration Curve

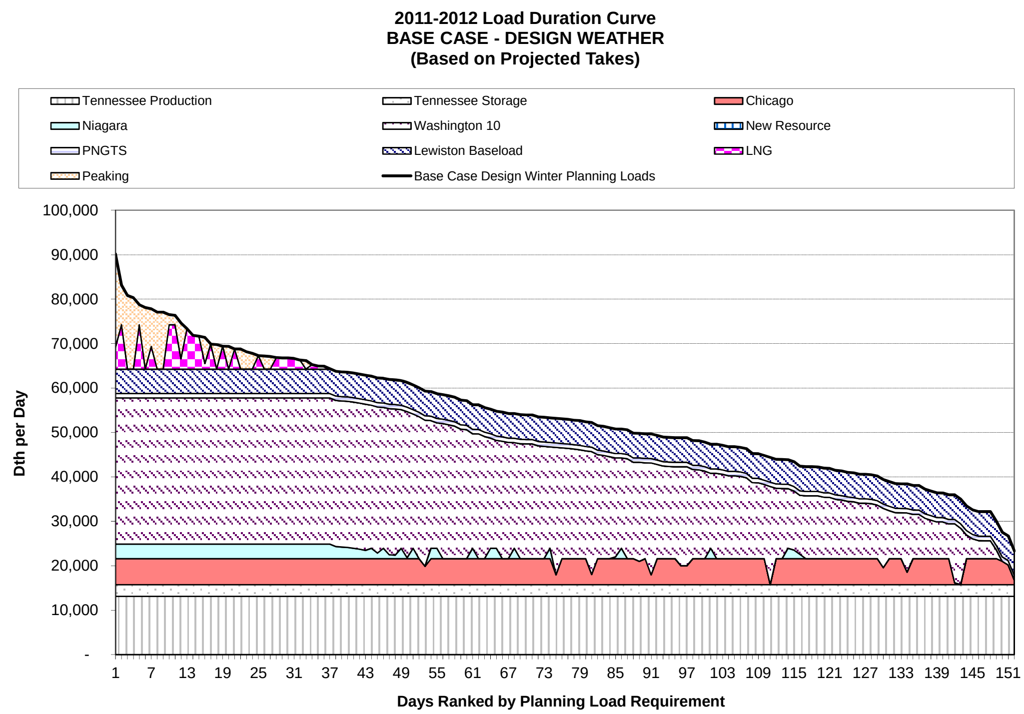


Figure VI-8(2): Base Case Normal Weather Load Duration Curve

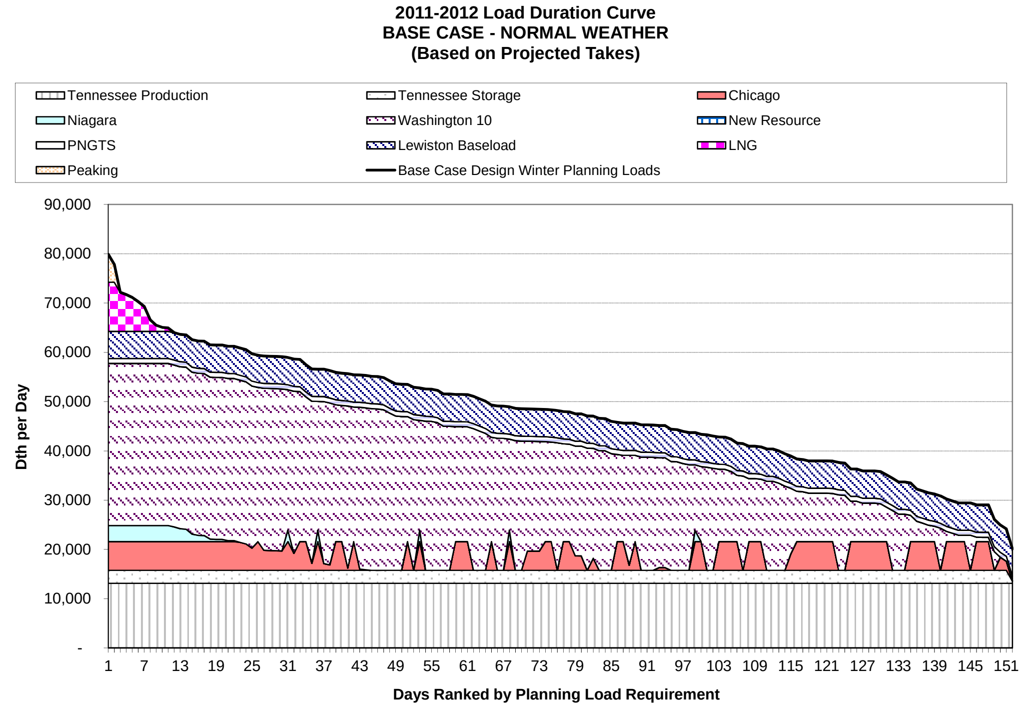


Figure VI-8(3): High Case Design Weather Load Duration Curve

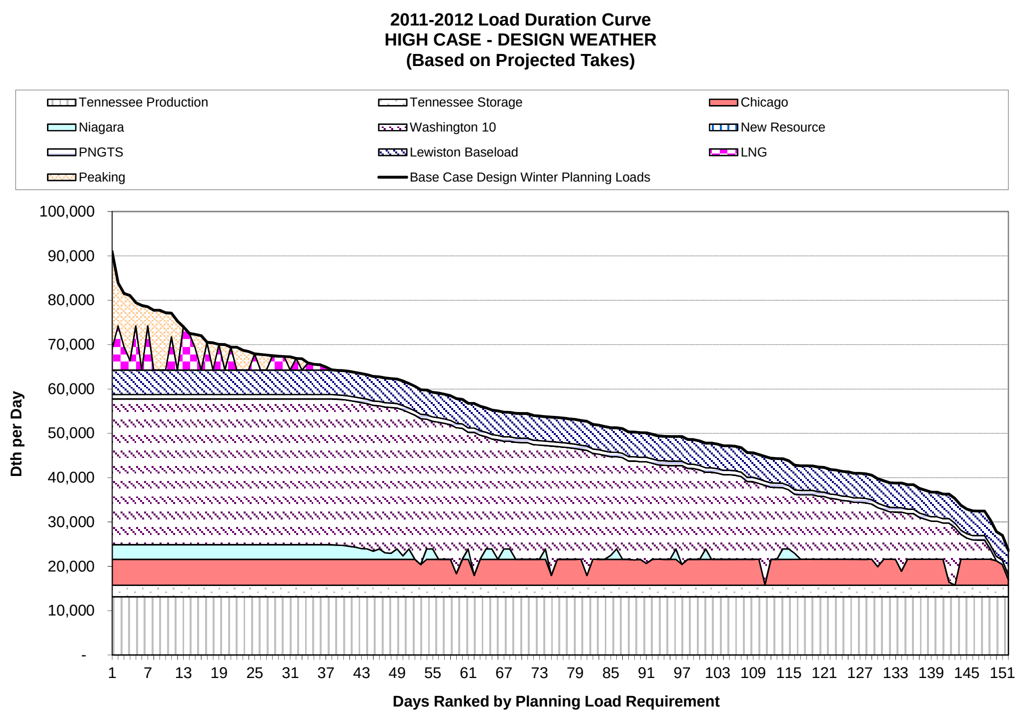


Figure VI-8(4): High Case Normal Weather Load Duration Curve

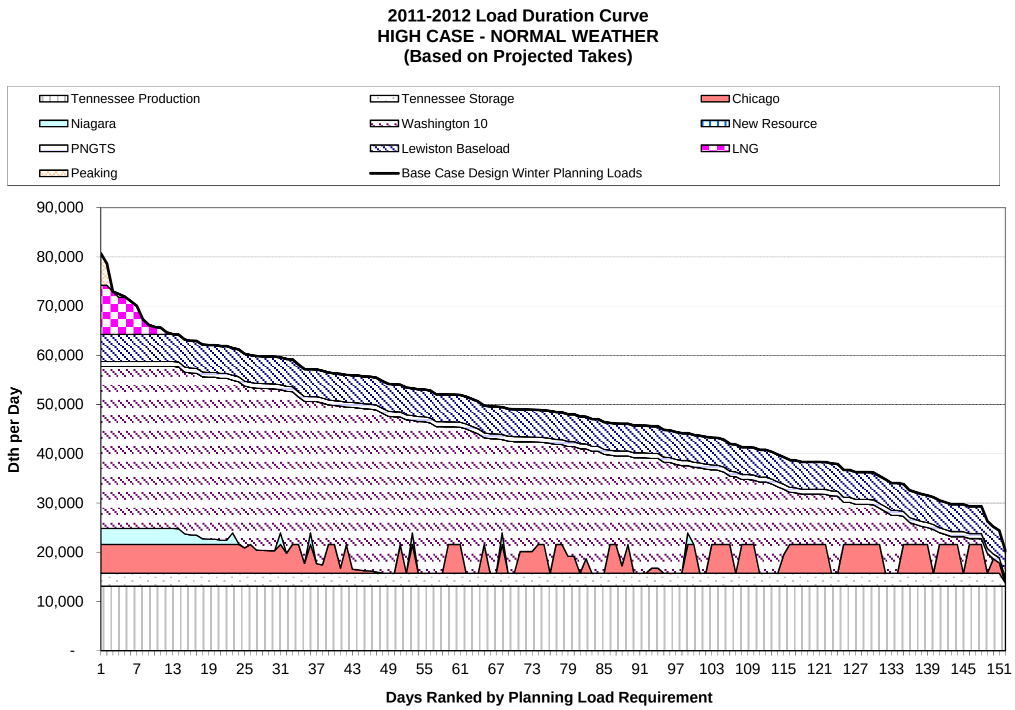


Figure VI-8(5): Low Case Design Weather Load Duration Curve

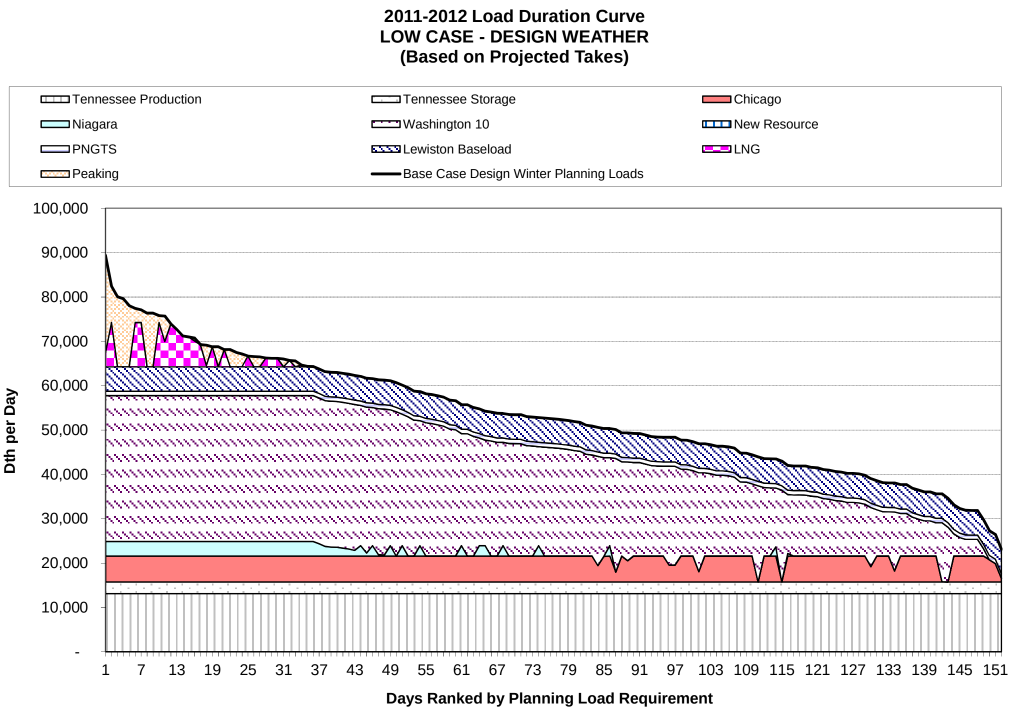


Figure VI-8(6): Low Case Normal Weather Load Duration Curve

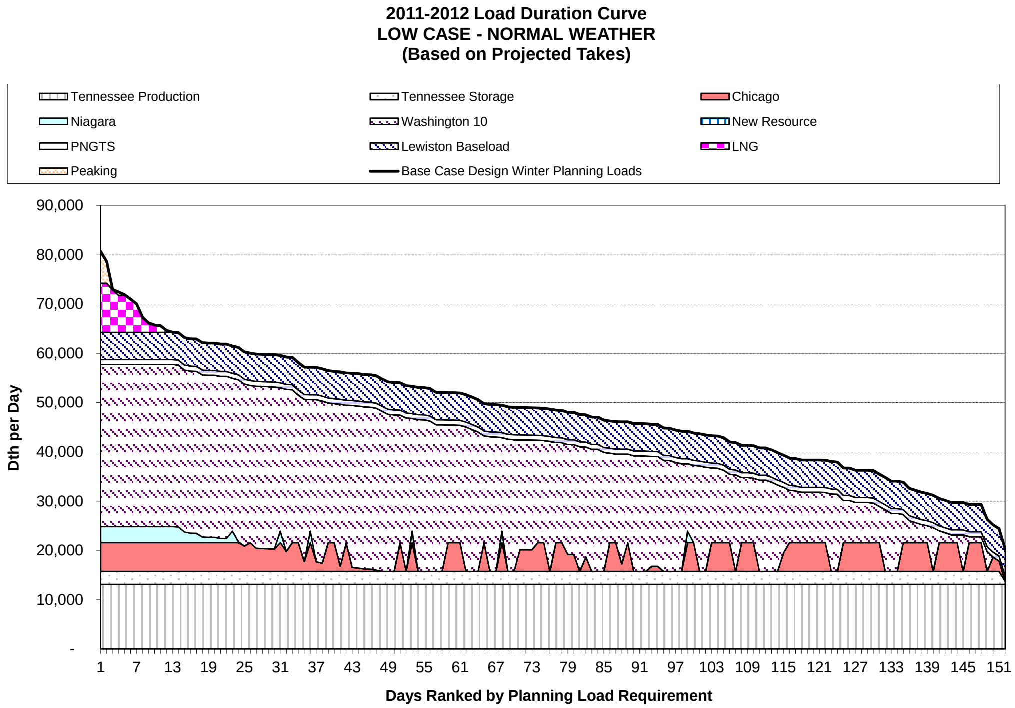
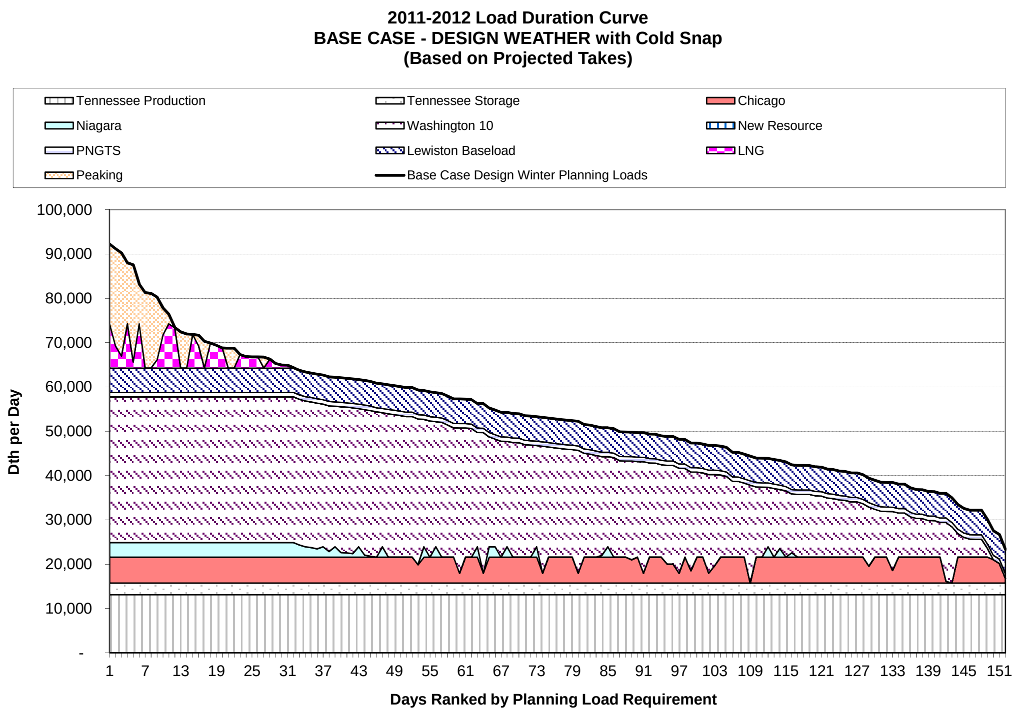


Figure VI-8(7): Base Case Design Weather with Cold Snap Load Duration Curve

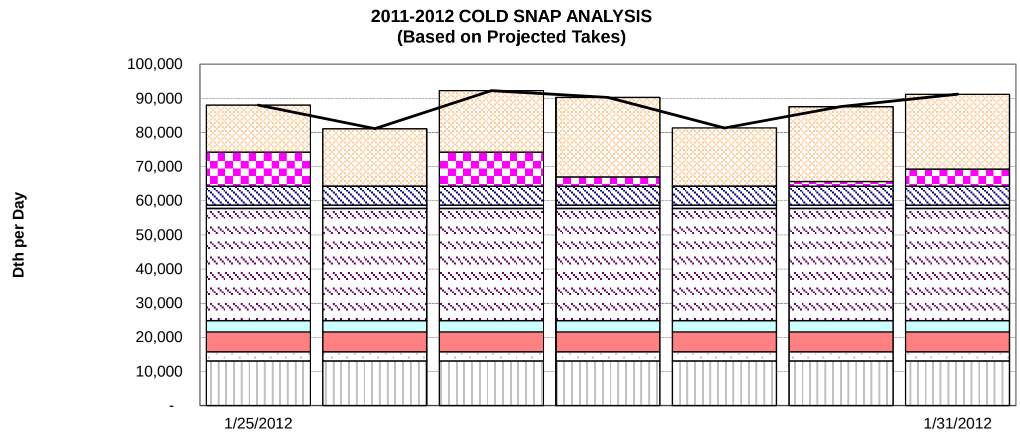


The Load Duration Curves provide an overall view of the portfolio dispatch under the full array of winter demand scenarios studied. One can see that, during the 2011-2012 winter period, depicted above, as demand increases above 65,000 Dth per day of planning load requirement, all non-peaking resources are required to meet demand. One can also see the utilization of peaking and LNG supplies only on days with high demand. Below 65,000 Dth per day of planning load, each scenario varies. One observation is that Tennessee Storage and Tennessee Production capacity is utilized each day of the winter period, due to the low delivered costs these resources provide. High utilization of Lewiston Baseload supply is due to the baseload nature of this commitment in 2011-2012. Chicago, Niagara and Washington 10 supplies provide flexibility to balance system resources with requirements. In total, the figures above show that Northern has the supply flexibility to meet a wide range of demand patterns.

(4) Cold Snap Analysis

Northern conducted a Cold Snap Analysis based upon its Base Case Design Weather load scenario. Appendix VI-6(7) is the Delivered City-Gate Commodity Costs by Supply Source for the Cold Snap Scenario, Appendix VI-7(7) is the Delivered City-Gate Commodity Costs by Supply Source for the Cold Snap Scenario, and Appendix VI-8(7), the Load Duration Curve for the Cold Snap Scenario. These schedules show the impact of a Cold Snap year over year and are explained in further detail in the Sendout® Results section. Appendix VI-9 provides the day over day dispatch of the system required to meet the seven days of planning load forecasted as the Cold Snap for each year in the Planning Period. The data presented in Appendix VI-9 are the same data used for the preparation of the Base Case Design Weather Load with Cold Snap Scenarios for Appendix VI-6 through VI-8. However, in Appendix VI-9, the focus is on the Cold Snap, itself, rather than on the entire period. Figure VI-9, below, provides the Cold Snap Analysis for the 2011-2012 Gas Year.

Figure VI-9: 2011-2012 Cold Snap Analysis



	1/25/2012	1/26/2012	1/27/2012	1/28/2012	1/29/2012	1/30/2012	1/31/2012
Peaking	13,747	16,809	17,993	23,260	17,022	21,923	21,923
LNG	10,000	45	10,000	2,743	45	1,380	5,022
Lewiston Baseload	5,500	5,500	5,500	5,500	5,500	5,500	5,500
PNGTS	997	997	997	996	996	996	997
New Resource	-	-	-	-	-	-	-
Washington 10	32,885	32,885	32,885	32,885	32,884	32,884	32,884
Niagara	3,282	3,282	3,282	3,282	3,282	3,282	3,282
Chicago	5,835	5,835	5,835	5,835	5,835	5,835	5,835
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109
Cold Snap Loads	87,997	81,104	92,244	90,254	81,318	87,553	91,195

Figure VI-9 presents the Cold Snap Analysis for the 2011-2012 winter period. Northern has the capabilities of meeting the projected Cold Snap, utilizing the current capacity resources without the need for additional resources. Northern's 2011-2012 gas supply portfolio can reliably serve projected Cold Snap planning loads.

2. Base Case Preferred Portfolio

Please refer to Appendix VI-10, Appendix VI-11 and Appendix VI-12, which are the Design Day Resource Balance, the Design Year Resource Balance and the Design Winter Resource Balance, respectively, restated to reflect anticipated contracting decisions associated with Northern's Preferred Portfolio, based upon the analysis presented above. The preferred portfolio reflects the indicated contracting decisions, which are discussed in detail, below. The preferred portfolio assumes that Northern's Planning Load requirement will grow at the base case levels provided in this study. As discussed further in the discussion of the individual contract decisions made to determine this preferred portfolio, the Company plans to issue annual RFP to provide flexibility to meet a wide range of actual growth scenarios. As discussed further in the Indicated Contracting Decisions section of this report, this Preferred Portfolio is presented, based upon the market price and pipeline rate assumptions, discussed in the Price Forecast section of this report. Northern's actual contracting decisions will be based upon updated price forecasts and analysis at the time of each decision is made.

Table VI-10, below, presents a summary of the Appendix VI-10, the Preferred Portfolio Design Day Resource Balance. Figure VI-10 provides the data in graphical form.

Table VI-10: Summary of Preferred Portfolio Design Day Resource Balance

Table VI-10. Summary of Preferred Portfolio Design Day Resource Balance					
Item	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Total Resources	106,838	106,510	108,428	110,980	113,447
Base Case Design Day Demand	105,131	106,510	108,428	110,980	113,447
Base Case Design Day Resource Balance	1,707	0	0	0	0
High Case Design Day Demand	106,084	108,537	111,576	115,318	119,034
High Case Design Day Resource Balance	754	(2,026)	(3,148)	(4,338)	(5,588)
Low Case Design Day Demand	104,178	104,503	105,339	106,766	108,071
Low Case Design Day Resource Balance	2,660	2,007	3,089	4,215	5,376

Figure VI-10: Preferred Portfolio Resource Balance – Design Day

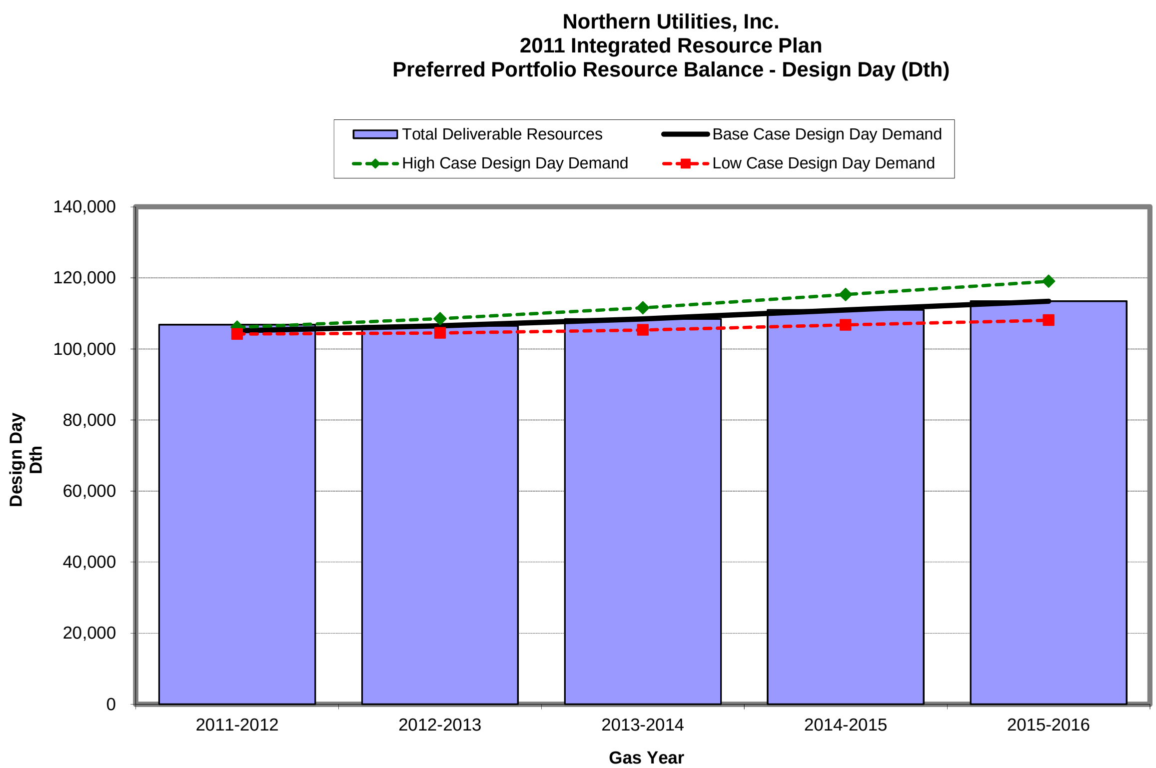
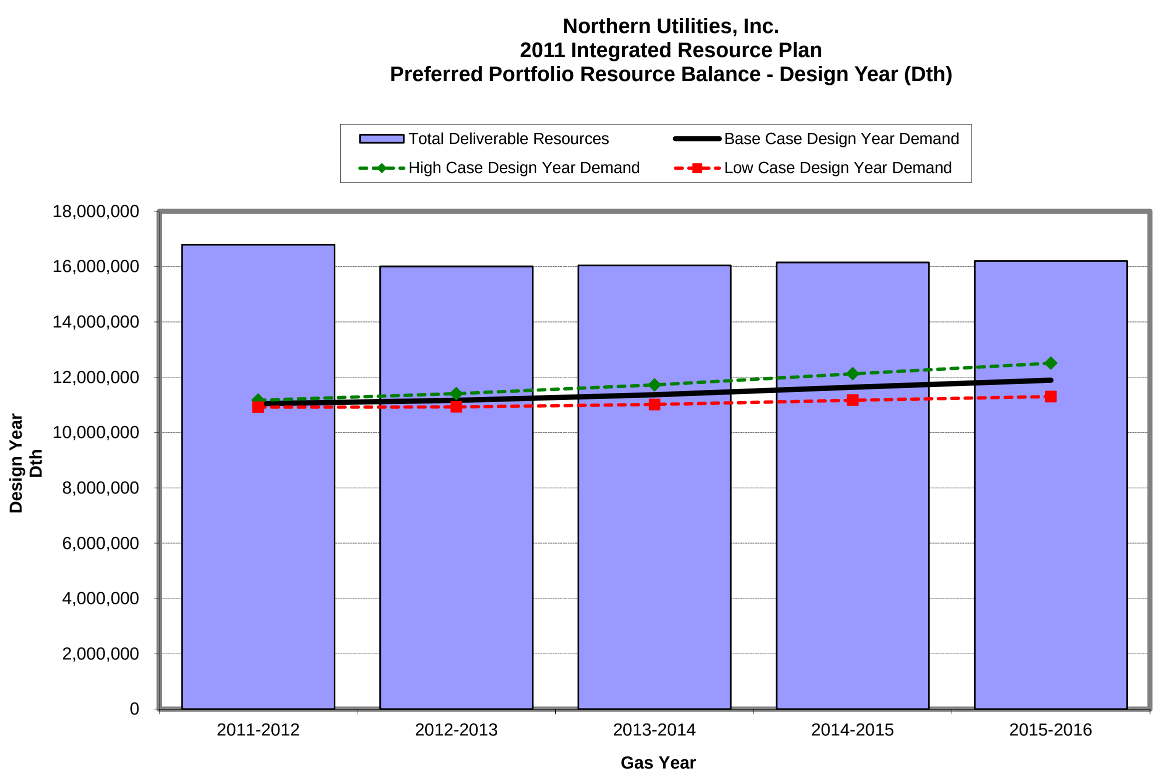


Table VI-11, below, presents a summary of the Appendix VI-11, the Preferred Portfolio Design Year Resource Balance. Figure VI-11 provides the data in graphical form.

Table VI-11: Summary of Preferred Portfolio Design Year Resource Balance

Table VI-11. Summary of Preferred Portfolio Design Year Resource Balance					
Item	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Maximum Resources - Design Year	16,793,230	16,011,982	16,049,399	16,153,854	16,208,544
Base Case Design Year Demand	11,043,458	11,168,073	11,365,939	11,640,980	11,894,129
Base Case Design Year Resource Balance	5,749,772	4,843,909	4,683,459	4,512,874	4,314,416
High Case Design Year Demand	11,170,737	11,408,366	11,724,561	12,125,590	12,510,506
High Case Design Year Resource Balance	5,622,493	4,603,617	4,324,838	4,028,263	3,698,039
Low Case Design Year Demand	10,916,655	10,930,799	11,015,166	11,171,505	11,302,755
Low Case Design Year Resource Balance	5,876,575	5,081,183	5,034,233	4,982,349	4,905,789

Figure VI-11: Preferred Portfolio Resource Balance – Design Year

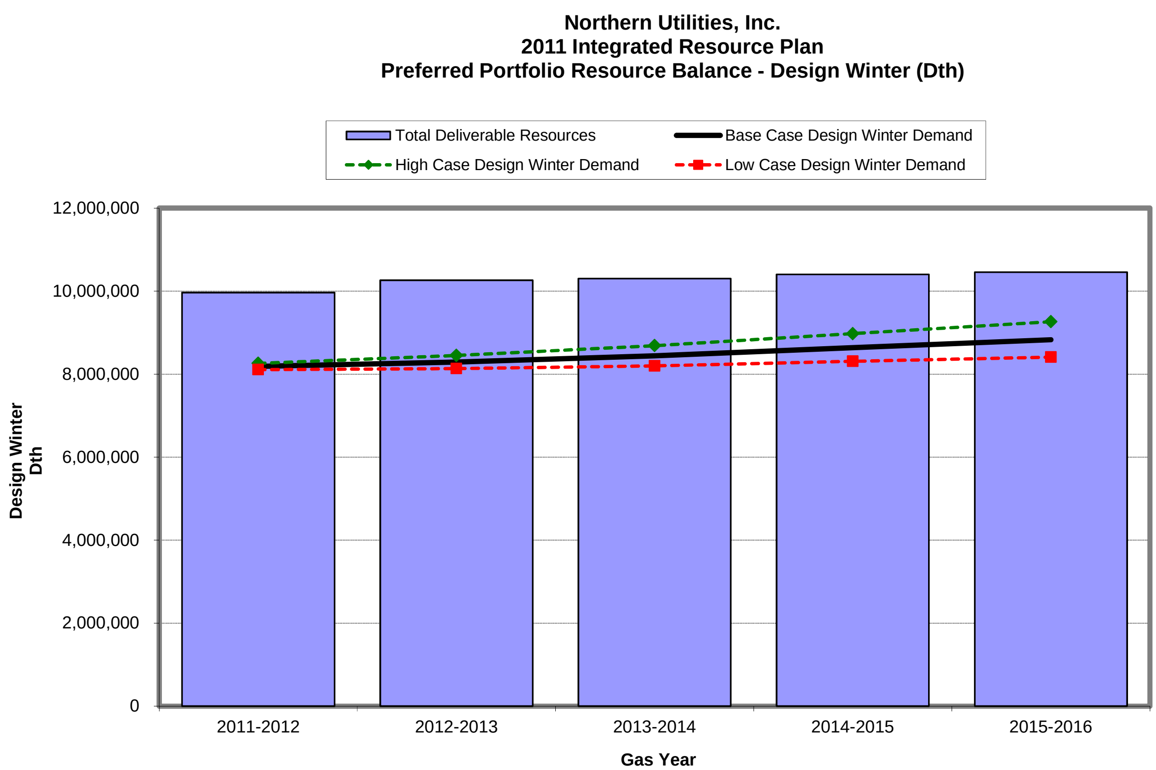


Finally, Table VI-12, below, presents a summary of the Appendix VI-12, the Preferred Portfolio Design Winter Resource Balance. Figure VI-12 provides the data in graphical form.

Table VI-12: Summary of Preferred Portfolio Design Winter Resource Balance

Table VI-12. Summary of Preferred Portfolio Design Winter Resource Balance					
Item	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Maximum Resources - Design Winter	9,964,338	10,262,658	10,300,075	10,404,530	10,459,220
Base Case Design Winter Demand	8,185,480	8,291,992	8,440,425	8,638,042	8,828,841
Base Case Design Winter Resource Balance	1,778,858	1,970,666	1,859,649	1,766,487	1,630,380
High Case Design Winter Demand	8,260,193	8,450,280	8,686,049	8,976,277	9,264,308
High Case Design Winter Resource Balance	1,704,145	1,812,378	1,614,025	1,428,252	1,194,912
Low Case Design Winter Demand	8,110,766	8,135,199	8,199,473	8,309,454	8,409,901
Low Case Design Winter Resource Balance	1,853,572	2,127,459	2,100,602	2,095,075	2,049,319

Figure VI-12: Preferred Portfolio Resource Balance – Design Winter



3. Indicated Contracting Decisions

While many of the contracting decisions listed below have already been implemented, the decisions are presented and discussed as they demonstrate the evaluation process and considerations made. For each contracting decision, the Sendout® Resource Mix results are provided as well as a brief overview of the considerations affecting the contract decision.

a) *Chicago Capacity Path Contract Decisions*

(1) Tennessee Contract 95196

Tennessee Contract 95196 (844 Dth into Granite and 1,382 Dth into Bay State Exchange) was set to terminate on 10/31/2012. Northern extended this agreement for 5 years to 10/31/2017.

The table below details the maximum daily volume of the Tennessee Contract 95196 contract selected by the Sendout® Resource Mix process for the five-year decision in each of the six demand scenarios analyzed during the planning period.

Tennessee Contract 95196 - (2,226 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Nov-13	2013-2014	2,226	607	2,226	1,621	1,623	-

The full contract volume is required to meet both Base Case Design and High Case Design demand scenarios. The company has elected to extend this agreement for the following reasons: (1) Capacity with Tennessee Gas Pipeline Zone 6 delivery points is scarce. It is very likely that the Company would be unable to reacquire this capacity should it turn this contract back to Tennessee. (2) The capacity is necessary for delivering supplies on upstream pipelines. Upstream capacity on Iroquois, TransCanada, Union and Vector pipelines would be stranded without Tennessee Contract 95196. (3) As demonstrated in the table above, the capacity is needed and economic for meeting Northern's expected design winter requirements. (4) Renewal of this contract is a requirement of the settlement filed in the Tennessee Rate Case on September 30, 2011. (5) Finally, the contract has substantial asset management and/or capacity release value, which was not modeled in Northern's Sendout® analysis.

(2) Algonquin Contract 93200F

Algonquin Contract 93200F (4,211 Dth into Bay State Exchange) was set to terminate on 10/31/2012. Northern extended this agreement for an additional year to 10/31/2013. This contract extends year-to-year, unless terminated upon one-year notice.

The table below details the maximum daily volume of the Algonquin Contract 93200F contract selected by the Sendout® Resource Mix process for each annual decision in each of the demand scenarios analyzed.

Algonquin Contract 93200F - (4,211 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Nov-12	2012-2013	4,211	4,211	4,211	4,211	4,211	4,211
Nov-13	2013-2014	4,211	4,211	4,211	4,211	4,211	4,196
Nov-14	2014-2015	4,211	4,211	4,211	4,211	4,211	4,211
Nov-15	2015-2016	4,211	4,211	4,211	4,211	4,211	4,211

The full contract volume is required to meet all demand scenarios. The company has elected to extend this agreement for the following reasons: (1) Capacity with Algonquin city-gate delivery points is scarce. It is very likely that the Company would be unable to reacquire this capacity should it turn this contract back to Algonquin. (2) The capacity is necessary for delivering supplies on upstream pipelines. Upstream capacity on Tennessee, Iroquois, TransCanada, Union and Vector pipelines would be stranded without Algonquin Contract 93200F. (3) As demonstrated in the table above, the capacity is needed and economic for meeting Northern's requirements. Northern has the option of renewing this capacity each year and plans to re-evaluate annually. (4) Finally, the contract has substantial asset management and/or capacity release value, which was not modeled in Northern's Sendout® analysis.

(3) Iroquois Contract R181001

Iroquois Contract R181001 (6,569 Dth connecting TransCanada and Tennessee portions of this path) was set to terminate 10/31/2013. This contract was extended until 10/31/2017.

The table below details the volume selected by the Sendout® Resource Mix process for each annual decision related to Iroquois Contract R181001 in each of the six demand scenarios analyzed.

Iroquois Contract R181001 - (6,569 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Nov-13	2013-2014	6,531	4,899	6,531	5,921	5,923	4,272
Nov-14	2014-2015	6,531	4,899	6,531	5,921	5,923	4,287
Nov-15	2015-2016	6,531	4,899	6,531	5,921	5,923	4,287

Substantially all of the Iroquois Contract R181001 contract capacity is utilized in the Base Design and High Design Demand Scenarios. Northern has extended the Iroquois capacity until 10/31/2017 for the following reasons: (1) Capacity on Iroquois is scarce. It is very likely that the Company would be unable to reacquire this capacity should it turn this contract back to Iroquois. (2) The capacity is necessary for delivering supplies on upstream pipelines. Upstream capacity on TransCanada, Union and Vector pipelines would be stranded without Iroquois Contract R181001. (3) As demonstrated in the table above, the capacity is needed and economic for meeting Northern's requirements. (4) Finally, the contract has substantial asset management and/or capacity release value, which was not modeled in Northern's Sendout® analysis. Northern has the option of renewing this capacity each year and plans to re-evaluate annually. Please note that the full amount of the contract was extended because Northern does not have the right to unilaterally reduce the contract volume in its extension decisions.

(4) Vector Contracts FT-1-NUI-0122 and FT-1-NUIC0122

Vector Contracts FT-1-NUI-0122 and FT-1-NUIC0122 (6,070 Dth at the beginning of this path) terminate on 3/31/2016. Northern does not have rights to unilaterally extend this agreement but is evaluating whether to seek an extension of this agreement to 10/31/2017 in order to line up with the termination dates of the Union and TransCanada capacity in this path.

The table below details the maximum daily volume of the Vector Contracts FT-1-NUI-0122 and FT-1-NUIC0122 contracts selected by the Sendout® Resource Mix process in each of the six demand scenarios analyzed during the planning period.

Vector Contracts FT-1-NUI-0122 & -C0122 - (6070 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Apr-16	2016-2017	-	-	-	-	-	-

Based upon current market conditions, Northern does not plan to seek renewal of the Vector Contracts FT-1-NUI-0122 and FT-1-NUIC0122 at their current rates for the following reasons: (1) The Company could procure supply from Dawn, Ontario, rather than the interconnect between Alliance and Vector Pipelines, as Dawn, Ontario is a liquid supply and storage point. (2) The commodity savings realized for purchasing supply based upon Chicago city-gate prices rather than Dawn, Ontario prices is insufficient under current market conditions to justify the current demand rates on Vector. The Company plans to review this decision as the contract comes closer to termination.

b) Tennessee Niagara Path Contract Decisions

(1) Tennessee Contracts 5292

Tennessee Contracts 5292 (1,406 Dth into Bay State Exchange) and 39735 (929 Dth into Granite) each terminate on 3/31/2015. Northern may extend these agreements for 5 years to 3/31/2020.

The tables below detail the maximum daily volume of the Tennessee Contracts 5292 and 39735 selected by the Sendout® Resource Mix process for the five-year decision in each of the six demand scenarios analyzed during the planning period.

Tennessee Contract 5292 (1,406 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Apr-15	2014-2015	1,406	1,406	1,406	1,406	1,406	1,406

Tennessee Contract 39735 (929 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Apr-15	2014-2015	929	929	929	929	929	929

The full contract volume is required to meet all demand scenarios analyzed. The Company plans to elect to extend this agreement for the following reasons: (1) Capacity with Tennessee Gas Pipeline Zone 6 delivery points is scarce. It is very likely that the Company would be unable to reacquire this capacity should it turn this contract back to Tennessee. (2) As demonstrated in the table above, the capacity is needed and economic for meeting Northern's expected design winter requirements. (3) Finally, the contract has substantial asset management and/or capacity release value, which was not modeled in Northern's Sendout® analysis.

c) Tennessee Storage Contract Decisions

(1) Tennessee Contracts 5195

Tennessee Contracts 5195 (259,337 Dth of Tennessee Storage Space) and 5265 (2,653 Dth into Granite) were set to terminate 10/31/2013. Northern extended these agreements through 3/31/2015, as part of Northern's compliance with the settlement of Tennessee's FERC rate case, docketed as RP11-1566. Northern may extend these agreements for 5 years to 3/31/2020.

The tables below detail the maximum volumes of the Tennessee Contracts 5195 and 5265 selected by the Sendout® Resource Mix process for the five-year decision in each of the six demand scenarios analyzed during the planning period.

Tennessee Contract 5265 (2,653 Dth)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Nov-13	2013-2014	2,653	2,653	2,653	2,653	2,653	2,653

Tennessee Contract 5195 (4,234 Dth MDW & 259,337 Dth MSQ)							
Month	Gas Year	Base		High		Low	
		Design	Normal	Design	Normal	Design	Normal
Nov-13	2013-2014	4,199	4,199	4,199	4,199	4,199	4,199
Nov-13	2013-2014	256,656	256,656	256,656	256,656	256,656	256,656

Nearly the full contract volume is required to meet all demand scenarios. The company has elected to extend this agreement for the following reasons: (1) Capacity with Tennessee Gas Pipeline Zone 6 delivery points is scarce. It is very likely that the Company would be unable to reacquire this capacity should it turn this contract back to Tennessee. (2) As demonstrated in the table above, the capacity is needed and economic for meeting Northern's expected design winter requirements. (3) Renewal of this contract is a requirement of the settlement filed in the Tennessee Rate Case on September 30, 2011. (4) Finally, the contract has substantial asset management and/or capacity release value, which was not modeled in Northern's Sendout® analysis. Northern would also note that Sendout® Resource Mix indicates a slight decrease in the Maximum Daily Withdrawal ("MDW") and Maximum Storage Quantity ("MSQ") of the storage contract. Given that Northern has only the right to extend the full contract volumes, Northern will elect to renew the full contract entitlements.

d) Algonquin Capacity Path Contract Decisions

(1) Algonquin Contract 93201A1C

Algonquin Contract 93201A1C (1,251 Dth into Bay State Exchange) was set to terminate 10/31/2012. The contract has been extended to 10/31/2013. This contract extends year-to-year, unless terminated upon one-year notice.

Currently, the Algonquin Contact 93201A1C capacity is released to a wholesale supplier. Northern entered into this release in April 2009 and it continues through October 2012. At the time of the release, Northern was not utilizing the capacity and was able to receive a price equal to Algonquin's maximum rate. Northern was also able to maintain a one-time recall with this release.

Although this piece of Algonquin capacity was not included in the Company's Sendout® analysis, the Company has elected to extend this capacity contract for an additional year. Referring to Table VI-5, a five-month supply, utilizing Algonquin Contract 93201A1C, was projected to cost an average of $6.24 per Dth, compared to a cost of $6.15 per Dth, a difference of $0.09 per Dth. The total annual difference in total cost would be approximately $17,000, which is calculated by multiplying $0.09 times 1,251 times 151 days of winter. However, the average cost calculations presented in Table VI-5 assume no capacity release and/or asset management revenue for the Algonquin contract 93201A1C. The Company's recent experience in the market indicates that it is reasonable to assume that the Company may earn significantly more than $17,000 in capacity release and/or asset management revenue. The projected capacity release and/or asset management revenue was not considered in the Table VI-5 calculations. Northern plans to utilize this capacity, beginning November 2012, to serve the Bay State Exchange Agreement. Therefore, Northern did not include this supply option in its Resource Optimization analysis. Algonquin Contact 93201A1C was not included in the Sendout® analysis prepared for this report, so there are no Resource Mix Decision to present. Therefore, the Company has elected to extend this contract for an additional year, which will reduce the Company's future needs for Tennessee Zone 6 delivered supplies.

4. Annual Market Procurement

Beyond the contract decisions discussed in the preceding section, Northern plans to conduct annual procurements for the following components of Northern's portfolio: (1) Peaking Supplies, (2) LNG Supplies, (3) Lewiston Baseload Supplies and (4) Tennessee Zone 6 Delivered Supplies. By procuring these components of the portfolio on an annual, rather than long-term basis, Northern will maintain flexibility to ensure that its portfolio of contracts is well-balanced with its supply requirements. Also, by keeping these portions of the portfolio in the short-term market, the Company will be positioned to take advantage of potential developments in the market place. The Company considers each of these components of the portfolio to be reliably procured through the marketplace. Please see the "Supply Procurement Process" Section (VI.B.4) for more detail on the procurement process.

5. Conclusion

The purpose of this Resource Portfolio Assessment was to provide an overview of the process utilized by Northern to make long-term supply-side resource decisions to meet the Planning Load requirement.

First, the Resource Portfolio Assessment identifies Northern's capacity requirements in the planning period. The Company's current portfolio and supply procurement processes were reviewed in detail. An initial Resource Balance was calculated on Design Day, Year and Winter bases to determine the current state of Northern's supply position through the five-year planning period. The initial Resource Balance analysis indicates a shortage in resources beginning in the 2012-2013 gas year, due to the expiration of Northern's current peaking supply arrangements and the upcoming renewal decisions on some portions of the current portfolio during the planning period. This decrease in contracted supplies, combined with projected increases in planning load requirements throughout the planning period, show that Northern must procure additional resources in order to meet its design planning load requirements.

Second, the Resource Portfolio Assessment discusses Northern's plan meeting these requirements in a reliable and economic manner. The Supply Resource Alternatives section listed the viable options for filling the resource need illustrated in the Resource Balance. These included both renewal of existing resources and viable alternatives. This section demonstrates that Northern is well-informed as to ongoing developments in the New England natural gas market and is actively considering the viability and economics of both existing and new resources. Northern's Resource Optimization Analysis described Northern's process for modeling its portfolio decisions, utilizing the Sendout® optimization model. The results of the Resource Optimization were presented, including reports providing Commodity Costs, Total Costs and Load Duration Curves for each of the seven demand scenarios analyzed. The Cold Snap Analysis was also presented and analyzed. It also provides useful insight into the dispatch of the portfolio and the relative cost of the various resources in the portfolio, including those which are not due for renewal within the planning period. This section demonstrates that Northern analyzes existing and new resources under a wide array of possible planning load scenarios in order to assure that the Northern's Preferred Portfolio will be capable of meeting each planning load scenario in an economic and reliable manner.

Finally, Northern provides its Preferred Portfolio, which reflects Northern's anticipated contracting decisions in order to address the initial Resource Balance deficiency. The Resource Balance is then re-stated, taking these anticipated contracting decisions into account. The anticipated contact decisions themselves are reviewed.

The Contract Decisions section provides a summary of each contract renewal considered, including both a discussion of the Resource Optimization results, as well as any considerations for renewal, which were not part of the Resource Optimization Analysis. While Northern either has renewed or plans to renew most of the contract renewals considered in this report, it did identify its Vector capacity in the Chicago Path as unlikely to be renewed in the current natural gas market. Northern has identified this change in its transportation portfolio in order to lower costs for consumers without sacrificing reliability. The supporting analysis of the contract renewals Northern has or plans to enter into are based on well-documented and transparent analysis.

The Contract Decisions section also includes a discussion of Northern's plan for replacing its delivered supplies, which do not have renewal provisions. Northern's plan to issue open RFPs, which consider both single- and multi-year supply arrangements, will allow Northern to efficiently react to changes in planning load requirements, while assuring that a portion of supplies are purchased at current market prices and that the portfolio reliably meets the Design Criteria.

In summary, the Resource Portfolio Assessment provides a comprehensive review of Northern's supply-side resource planning process and demonstrates that Northern's supply plans for supply-side resources in an economic and reliable manner.

VII. Compliance with Directives

The following table lists the requirements that are included in Northern's 2006 Long-Range Integrated Resource Plan Stipulation and Settlement Agreement ("Settlement Agreement"), approved by the Maine Public Utilities Commission on February 24, 2010 in Docket No. 2006-390 and approved by the New Hampshire Public Utilities Commission on April 5, 2010 in Docket No. DG 06-098.

	Settlement Agreement Terms (and Reference)	Northern IRP Compliance
1	**Planning Period**. The next IRP and all subsequent IRPs shall cover a planning period that includes the next five Gas Years after the filing date of the IRP, where "Gas Year" is the twelve months from November through the following October. (Section II.B.4)	The planning period in this IRP includes one partial Gas Year (2010/11) and five full Gas Years (2011/12-2015/16) after the filing date.
2	**GSGT Study**. If issues related to the Granite State Gas Transmission ("GSGT") study of potential integration are not resolved by the time the next IRP is filed, the next IRP will include a discussion of the regulatory and operational alternatives that were considered in the GSGT Study (Scenarios), the results of Northern's economic evaluation of these Scenarios, and the impact these Scenarios may have on Northern's future resource plans. If the issues related to the GSGT Study of potential integration have been resolved at the time the next IRP is filed, Northern's resource plans included in the next IRP will reflect that final decision. (Section II.B.7)	The GSGT Integration Study was given considerable time and effort on the part of the staffs of both commissions, the public and consumer advocates in both states, and Unitil. The Study was the subject of an extended technical conference and substantial discovery. Unitil believes that issues related to the GSGT Integration Study have been exhausted and the current GSGT configuration has been shown to be optimal. As such, the IRP reflects GSGT as currently configured.
3	**Demand Forecasts**. Northern shall submit separate design day demand and annual demand forecasts for its firm sales and transportation-only customers. The design day demand forecast will present three scenarios: base case, high case and low case. The annual demand forecast will be developed using both normal and design year weather conditions, each of which will also be presented under base case, high case and low case demand scenarios. The high and low case scenarios will be based on extreme but plausible growth rates. In addition, Northern will identify and explain any notable deviations from historical growth trends reflected in its demand forecast. Finally, Northern will discuss the predictive ability of its demand forecast models and explain how the next IRP addresses uncertainty associated with different demand scenarios. (Attachment A, Section A.1)	Section III includes a discussion of (a) Nor--mal Year base case annual demand forecasts; and (b) High and Low Growth Normal Year scenarios. Section IV.D includes a discussion of (a) Design Year base case annual demand forecasts and (b) High and Low Growth Design Year scenarios. Section IV.E includes a discussion of (a) Design Day (base case) demand forecasts and (b) High and Low Growth Design Day scenarios. Discussions of demand growth trends are included in the description of each Customer Segment forecast.

	Settlement Agreement Terms (and Reference)	Northern IRP Compliance
4	**Resource Balance**. Northern shall provide information showing the difference between projected design day demand based on expected low and high demand cases and the peak-day resource capacity based on existing contracts not scheduled to expire during the planning period, known as the Resource Balance. In addition, Northern shall provide information showing the difference between projected annual demand based on expected low and high demand cases and annual supply capability based on existing contracts not scheduled to expire during the planning period. This information will be provided in both tabular and graphical form. Northern shall also provide a discussion of the potential variability in the Resource Balance and the implications of the Resource Balance for lowest cost resource procurement. (Attachment A, Section A.2)	Section VI.C compares Northern's resources currently under contract to the projected design day and design year demand, including alternative low and high case scenarios.
5	**Planning Standards**. Northern's design day and design year planning standards shall be based on statistical analyses of an updated set of weather data and shall include consideration of how, if at all, climate change is or should be reflected in the plan. Northern will investigate whether historically observed weather is normally distributed and, if not, address the implications of this finding for the calculation of planning standards. In addition to determining the adequacy of its resource portfolio under design day and design year weather conditions, Northern shall evaluate the capability of its resource portfolio to meet sendout requirements during a protracted period of very cold weather (i.e., conduct a cold snap analysis). (Attachment A, Section A.3)	The Design Year planning standard is discussed in Section IV.D. The Design Day planning standard is discussed in Section IV.E. Climate change is discussed in Section IV.B. The distribution of historical EDD is discussed in Appendix IV-1. The Cold Snap analysis is discussed in Section IV.F.
6	**Supply-Side Resource Assessment**. Northern shall identify reasonably available supply-side resource options that are capable of meeting the projected resource balance over the planning period, including the renewal of existing contracts scheduled to expire during the planning period. The methods that Northern uses to evaluate supply-side resource options shall be described in full in the next IRP along with the results of the evaluations. (Attachment A, Section A.4)	Alternative transportation, storage and commodity supplies are discussed in Section VI.D. In addition, supplemental information from the Northeast Gas Association (NGA) is provided in Appendix VI-1A.

	Settlement Agreement Terms (and Reference)	Northern IRP Compliance
7	**Demand-Side Resource Assessment**. Northern shall present estimates of the technical and economic potential for energy efficiency in its Maine and New Hampshire divisions, which in the case of New Hampshire shall be taken from, or based upon, the GDS Associates, Inc. 2009 report titled Additional Opportunities for Energy Efficiency in New Hampshire. Such estimates shall account for expected savings from existing programs that have been approved for implementation in Maine or New Hampshire. Northern shall also include in the next IRP estimates of avoided costs: (i) a description of its avoided cost methodology; (ii) the resulting avoided cost forecast by cost component; (iii) a description of the approach used to define and evaluate potential programs; (iv) avoided costs by such program; (v) estimated implementation costs by such program; and (vi) a ranking of evaluated potential programs based on appropriate criteria including avoided costs. In assessing demand-side resource programs, Northern shall use the Total Resource Cost (TRC) test for evaluating cost effectiveness. Northern shall model the expected savings from efficiency measures previously installed, and expected to be installed, in its Maine and New Hampshire divisions under programs that have been approved for implementation in Maine and New Hampshire as a reduction in its demand forecast. (Attachment A, Section A.5)	Estimates of technical and economic potential for both divisions, which were taken or extrapolated from the GDS Study, after accounting for expected savings from existing programs at currently approved and projected budget levels, are provided in Section V.E. Estimates of avoided costs, which were taken from the 2011 Avoided Energy Supply Costs Report, are reviewed in Section V.F. A listing of potentially expandable programs is provided in Section V.G. along with an analysis of the potential costs and savings associated with expanded energy efficiency programs Expected savings from efficiency measures expected to be installed under existing energy efficiency programs were subtracted from the demand forecast, as described in Section III.D.2.
8	**Integration of Demand-Side and Supply-Side Resources**. Northern shall describe its process for integrating demand-side and supply-side resources in a manner that meets customers' future needs at the lowest reasonable cost while maintaining reliability and taking into account other non-cost planning criteria. Among other things, the Company should discuss how differences in the reliability of supply-side and demand-side resources are taken into account in the integration process and whether it expects to acquire the incremental resources through Company-sponsored programs and/or programs acquired on its behalf by third settling parties through an RFP process. (Attachment A, Section A.6)	The issues associated with Demand-Side resources as an element of integrated resource planning are reviewed in Section V.B. of the report. Northern recommends that it prepare a white paper relative to the expansion of energy efficiency programs in New Hampshire for submission to the CORE energy efficiency stakeholders.

	Settlement Agreement Terms (and Reference)	Northern IRP Compliance
9	**Preferred Portfolio**. The next IRP shall include a description of the results of the integration process; namely the preferred portfolio of existing and new resources (on a design day and design year basis) that meets forecasted loads over the planning period at lowest reasonable cost. The description of the preferred portfolio for the next IRP will be supplemented with a discussion of the key factors that led to the conclusion that renewal of existing contracts is economic (or uneconomic) and that certain new resource options are more cost-effective than others. In addition, the preferred portfolio will be provided in both tabular and graphical form. Finally, a copy of the next IRP shall be provided for informational purposes to the New Hampshire Energy Efficiency & Energy Sustainability Board and to Efficiency Maine. (Attachment A, Section A.7)	Section VI.E. details the results of Northern's resource portfolio analyses, including its design day and design year scenarios. This section discusses pending renewal decisions and alternative resources under consideration, along with Northern's current assessments and rationales. Graphical depictions of the preferred portfolio are provided in the text of Section VI.E., while Appendix VI-9 through VI-11 provides detailed tabular reporting of the resources used to meet demand under the scenarios studied in tabular form. A copy of the complete IRP will be sent to both the New Hampshire Energy Efficiency & Energy Sustainability Board and to Efficiency Maine.
10	**Plan Flexibility**. The Resource Balance discussion to be included in the next IRP shall explicitly consider the flexibility inherent in Northern's demand-side and supply-side resource planning process, including Northern's process for acquiring additional resources or releasing contracted resources in the event that its actual customer demand is greater than or less than forecast needs in the short or long term. (Attachment A, Section A.8)	The retail choice environment can create significant changes in terms of expected customer demand and the availability of portfolio resources that are available to both sales service and transportation customers. Plan flexibility is discussed, from a short and long term contracting perspective, in Section VI.A.5.
11	**Hedging**. The next IRP shall include a description of Northern's goals and strategy to financially hedge the cost of gas supply. This description should address the following issues: (i) why financial hedging is appropriate; (ii) the type of financial products the Company purchases to hedge certain supply costs; (iii) the timing as to when any financial hedges are purchased (e.g., close to delivery or multiple months prior to delivery); (iv) the time periods for which financial hedges are purchased (e.g., peak or off-peak); and (v) the magnitude of the Company's hedging program in relation to its sales requirements. To place this strategy in context, Northern shall describe generally its gas supply price risk management strategy, the organization responsible for its development and implementation, and the internal protocols that allow for its timely execution. (Attachment A, Section A.9)	The parameters and purpose of Northern's financial hedging program, as well as the methods by which transactions are implemented, are discussed in Section VI.A.6.

	Settlement Agreement Terms (and Reference)	Northern IRP Compliance
12	**Demand Forecasting Methodology**. ***Distinguishable Customer Segments by Division***. The demand forecast that Northern prepares for the next IRP shall consist of separate demand forecasts for the Maine and New Hampshire Divisions that are derived from a statistical analysis of data relating to distinguishable customer segments, such as: Residential Non-Heating (RNH); Residential Heating (RH); Commercial and Industrial Low Load Factor (C&I LLF); and Commercial and Industrial High Load Factor (C&I HLF) (collectively, Customer Segments). The demand forecast for each Customer Segment will be derived from separate forecasts of number of customers and use per customer using a standard commercially available regression analysis package.	***Customer Segments***. As discussed in Section III.C, separate number of customer and use per customer forecasts were developed by Customer Segment for the Maine and New Hampshire Divisions using the PASW/SPSSTM (Release 18.0.0) software package. Results from these models are contained in Section III.C and in Appendix III-6 and Appendix III-7.
	Data Description and Assessment of Reasonableness. The forecast model data will be obtained from Northern's historical records and/or from commercial vendors. To allow the settling parties to assess the reasonableness of Northern's demand forecast, IRP filings will include detailed information on the processes used to develop the demand forecasts including: (1) a list of all variables and model forms that were tested in developing each forecast model; (2) a discussion of the reasons that any tested variable or model form was not included in the final forecast models; (3) an analysis of the "goodness of fit" of the final forecast models and comparison to other tested models; (4) a discussion of the reasonableness of Northern's forecast including the reasonableness of assumptions relating to expected changes in use per customer and changes in regional and national economic growth over the planning period.	***Data Description***. Section III.C describes the data used to develop the demand forecasts. Appendix III-2 contains a list of the variables tested in the models; Appendix III-5 contains a description of the modeling process used; and detailed statistical results for each model are provided in Appendix III-6 and Appendix III-7. Goodness of fit was evaluated by examining the R^2 of each model, as well as reviewing residuals, which are presented among the statistical results. Discussions of demand growth trends and the major drivers are included in the description of each Customer Segment forecast:
	Adjustments to Forecast. Natural gas demand for company use will be added to the demand forecast based on historical data, with adjustments to reflect changes in Company use. In addition, since the customer segment forecasts will be based on metered demand at customer premises, the demand forecast will be grossed-up for lost and unaccounted for gas to obtain the equivalent city-gate sendout requirement. The demand forecast will be reduced by the amount of incremental energy savings from approved DSM programs implemented during the planning period. Finally, the billing month demand forecast will be converted to calendar months.	***Adjustments***. The Company Use forecast is described in Section III.D.4. Losses and unbilled sales are discussed in Section III.D.5. Expected energy efficiency savings from approved programs were subtracted from the demand forecast, as discussed in Section III.D.2.
	Demand Forecast Expectations. The forecast shall be a rigorous analysis based on sound application of statistical and economic principles and approaches that is described in detail in the filing. (Attachment B)	***Expectations***. Sections III and IV, supported by the materials in Appendix III and Appendix IV, describe the forecasting process in detail and demonstrates the sound application of statistical and econometric principles and approaches.