National Grid

The Narragansett Electric Company

Gas Long-Range Resource And Requirements Plan For the Forecast Period 2015/16 to 2024/25

March 10, 2016

RIPUC Docket No. 4608

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

nationalgrid

Filing Letter

Jennifer Brooks Hutchinson
Senior Counsel

March 10, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Long-Range Gas Supply Plan
Forecast Period 2015/16 to 2024/25
Docket No. 4608

Dear Ms. Massaro:

Enclosed are ten (10) copies of National Grid's[1] recently completed Long-Range Gas Supply Plan (Plan) for the forecast period 2015/16 to 2024/25 pursuant to Rhode Island General Laws § 39-24-2. During the most recent Gas Cost Recovery proceeding, the Company and the Division of Public Utilities and Carriers (Division) agreed to defer the issues that the Division's consultant raised in relation to the Company's forecast methodology until such time as the Company submitted a new supply plan. The Company would welcome an opportunity to present the enclosed Plan to the Rhode Island Public Utilities Commission and the Division at a technical session.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Steve Scialabba, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid ("the Company").

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Section I
Introduction

I. Introduction

This filing presents the Long-Range Resource and Requirements Plan (Supply Plan) for The Narragansett Electric Company d/b/a National Grid (Company), for the forecast period November 1, 2015 through October 31, 2025. The Company is submitting this Supply Plan to the Rhode Island Public Utilities Commission (PUC) pursuant to Rhode Island General Laws § 39-24-2. The Company is a public utility under the provisions of R.I.G.L. § 39-1-2 and provides natural gas sales and transportation service to approximately 250,000 residential and commercial customers in 34 cities and towns. The statute requires the Company to submit to the PUC every two (2) years a long-range energy plan for the five (5) year period subsequent to the date the plan is submitted, and to include all assumptions and methodologies that the Company used in formulating the plan.

Although the statute only requires a five-year forecast period, the Company has expanded the instant Supply Plan to include a ten-year forecast period in order to encompass the period over which the Company has made decisions to enter into long-term arrangements in order to continue to provide a least-cost, reliable portfolio.

This Supply Plan is designed to demonstrate that the Company's gas-resource planning process has resulted in a reliable resource portfolio to meet the combined forecasted needs of the Company's Rhode Island customers at least-cost. To make this demonstration, the Supply Plan presented herein includes: (i) a step-by-step description of the methodology the Company uses to forecast demand on its system; (ii) a discussion of the process and assumptions that the Company uses to develop its resource portfolio to meet customer requirements under design-weather conditions; and (iii) a complete inventory of the expected available resources in the Company's portfolio, and a demonstration of the adequacy of the portfolio to meet customer demands under a range of weather.

Section II
Planning Results
Overview

II. Overview of Planning Results

As described in detail in this filing, the Company's planning process is based on a comprehensive methodology for forecasting customer load requirements using a series of econometric models to determine the annual growth expected for residential heating, residential non-heating and commercial and industrial markets for both sales and transportation services. To determine the projected growth over the forecast period, the econometric models use historical economic, demographic, and energy price data, as well as weather data to determine total energy demand. The Company then analyzed load reductions expected to be achieved through the implementation of its revised energy-efficiency programs, because these reductions are exogenous to the demand forecast generated by the econometric models.

The results of the Company's Base Case demand forecast (See Chart III-B-3) indicates that, over the ten-year forecast period, the residential heating market is projected to increase by an average of 157 BBtu per year, the residential non-heating market is projected to decrease by an average of 11 BBtu per year and the commercial/industrial market is projected to grow by 267 BBtu per year. The Company projects that growth opportunities in non-traditional markets over the forecast period are reflected in the results of the econometric models. The Company is not projecting any incremental growth in these markets beyond what it experienced in the historical period upon which these models are based.

As explained below, the Company's demand forecast is then converted to supply requirements at the Company's citygates. The end result of the forecasting process is that projected sendout requirements increase over the forecast period averaging 443 BBtu (approximately 1.2 %) per year under normal weather conditions (See Section III.D.2).

To ensure that the Company maintains adequate supplies in its portfolio to meet the projected customer load requirements, the next step in the planning process involves an analysis to define the planning standards for the coldest planning year, known as the "design year" and the coldest planning day, known as the "design day". The results of the analysis support the Company's determination to define a design year at 6,280 heating degree day (HDD) with a probability of occurrence of 1 in 35.28 years and a design day at 68 HDD with a probability of occurrence of 1 in 98.86 years. Combining the results of the design planning standards definition and the load forecasting process, the Company is projecting its Base Case design-year sendout requirements to increase over the forecast period by an average of 487 BBtu, or approximately 1.2 % per year, and design day sendout to increase by an average of 4.4 BBtu, or 1.2 %, per year (See Section III.F).

After the forecast of customer requirements are determined, the next step in the Company's planning process is to design a resource portfolio to meet those requirements in the most reliable and least-cost manner possible. To that end, the Company uses the SENDOUT® Model (a proprietary linear programming model developed by Ventyx) to determine the adequacy of the existing portfolio in meeting the forecasted requirements and to identify any shortfalls during the forecast period. SENDOUT® allows the Company to determine the least-cost, economic dispatch of its existing resources subject to contractual and operating constraints and identifies the need for and type of additional resources during the forecast period, if any. To evaluate the flexibility and adequacy of the resource portfolio under a range of reasonably foreseeable conditions, the portfolio is assessed under design and normal weather conditions as well as a cold snap weather scenario. The Company's resource plan is sufficient to meet design-year load requirements throughout the forecast period with the addition of incremental capacity and citygate delivered purchases.

For the cold-snap weather scenario, the Company used a 14-day cold snap occurring in the coldest 14-day period of the Company's normal year (15 January - 28 January) by evaluating January weather data from 1976-2015. The Company uses the results of the cold snap scenario to test the adequacy of inventories and refill requirements. The Company's resource plan shows that it has adequate resources available to meet cold-snap sendout requirements in all years of the forecast, with the addition of incremental capacity and citygate purchases.

Please note that communications regarding this Supply Plan should be directed as follows:

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As discussed briefly above, this document is organized into the following principal sections:

- Section III reviews the Company's econometric demand forecasting methodology and discusses the development of the forecast of customer sendout requirements.
- Section IV discusses the design of the resource portfolio, the analytical process and assumptions, the expected available resources, and the adequacy of the portfolio in terms of meeting forecasted customer requirements under design weather conditions; and,
- Section V contains the charts and tables referenced within the document.

The analysis presented in these sections demonstrates that the Company's planning process results in a reliable resource portfolio that is adequate to meet the forecasted needs of its customers at least-cost with the addition of incremental pipeline capacity as well as long-term LNG supply services and citygate delivered purchases.

III. Forecast Methodology

III.A. Introduction

The Company's forecast methodology supports its supply planning goal to ensure that it maintains sufficient supply deliverability in its resource portfolio to meet customers' requirements on the design day and that it maintains sufficient supply under contract and in storage (underground storage and LNG) to meet customers' requirements over the design year. Each year, the Company employs the same process of preparing a multi-year forecast in order to ensure that the portfolio has sufficient resources for the upcoming winter period, as well as sufficient time to contract for additional resources should they be required. Specifically, the term "customer" as used herein means those customers for whom the Company must make capacity planning decisions[1].

The Company develops its underlying demand forecast from econometric models of its customer billing data. This data is available by month and by rate class. The Company models its daily resources and requirements with its SENDOUT® linear programming software modeling package, and hence, it needs as input a forecast of daily customer requirements.

Accordingly, the Company developed its ten-year forecast of customer requirements under design-weather planning conditions using the following process:

1. Forecast Retail Demand Requirements

   Retail demand requirements are based on customer billing data, which is available by rate class and by month. The Company uses a series of econometric models to develop a forecast of retail demand requirements for traditional markets (i.e., residential heating, residential non-heating, and commercial and industrial (C&I) customers). The forecast of retail demand requirements for traditional markets is summed to determine the total retail demand requirements over the forecast period. This forecast of retail demand is disaggregated into monthly billed and unbilled volumes and, hence, can be calendarized for supply planning purposes.

2. Develop Reference Year Sendout Using Regression Equations

   The daily values of the Company's wholesale sendout in the reference year (April 2014 – March 2015) serves as the basis of allocating the monthly retail demand forecast to the daily level. Because actual sendout data for the reference year is a function of the weather conditions experienced in that year, the Company develops this allocator for sendout using regression equations to normalize the sendout in the reference year based on normalized weather data.

[1] The Company makes capacity planning decisions for its sales and non-grandfathered transportation (Customer Choice) customers.

3. Normalize Forecast of Customer Requirements

   The Company's monthly retail demand forecast is allocated to the daily level based on the use of its daily wholesale sendout regression equation and its normal daily heating degree day data. This step sets the Company's total normalized forecast of customer requirements over the ten-year forecast period.

4. Determine Design Weather Planning Standards

   The Company performs an analysis to determine the appropriate design day and design year planning standards for the development of a least-cost reliable supply portfolio over the forecast period.

5. Determine Customer Requirements Under Design Weather Conditions

   Using the applicable design day and design year weather planning standards, the Company determines the design year sendout requirements and the design day sendout requirements. These design sendout requirements establish the Company's resource requirements over the forecast period.

To test the sensitivity of the resource portfolio to variations away from the Company's base case forecasted customer requirements, the Company developed a high-case customer requirements scenario. The high-case scenario is based on the Moody's economy.com high economic growth case.

Based on the forecast, the Company projects base-case growth in customer requirements for its Sales and Customer Choice customers of 3,782 BBtus over the forecast period or 420 BBtus per year (assuming normal weather) (See Section III.D.2). Overall, this growth in firm sales represents a 10.8 percent total increase in sendout requirements over the forecast period, or 1.2 percent per year on average.

Based on the forecast, the Company projects high-case growth in customer requirements for its Sales and Customer Choice customers of 4,071 BBtus over the forecast period or 452 BBtus per year (assuming normal weather) (See Section III.D.2). Overall, this growth in firm sales represents a 11.7 percent total increase in sendout requirements over the forecast period, or 1.3 percent per year on average.

The development of the Company's ten-year forecast of customer sendout requirements, based on the steps set forth above, is described in the following sections.

III.B. Forecast of Retail Demand (Demand Forecast)

The first step in the Company's forecasting methodology is the generation of its retail demand forecast, which is prepared through econometric and statistical modeling.

III.B.1 Demand Forecast for Traditional Markets

III.B.1.a Service Territory Specific Data Availability

The Company used its monthly customer billing data (volume and number of customers) for the period August 2010 through February 2015 to define the dependent variables in its econometric models. The billing data was modeled at the Company's internal rate code level for the various classes of customers (residential heat, residential non-heat, commercial and industrial heat, commercial and industrial non-heat, etc.). Additionally, the data was also divided into the sales customer classes, the Customer Choice customer classes, and the "zero-capacity" (i.e. grandfathered transportation) customer classes. Specifically, the table below lists the relevant customer classes and rate classes used in the Company's analysis.

	Sales	Customer Choice	Zero-Capacity
Residential Heating	400, 402		
Residential Non-Heating	401, 403		
Commercial/Industrial Heating	404, 405, 408, 409, 412, 413, 416, 444	406, 407, 410, 411, 414, 415, 443	Z407, Z411, Z415
Commercial/Industrial Non-Heating	417, 420, 421, 424	418, 419, 422, 423	Z419, Z423
Non-Firm	433, 435, 437, 439, 441	434, 436, 438, 440, 442	

III.B.1.b Econometric Models

With volume and customer data as identified above, the Company developed econometric models for the number of customers and use per customer (the quotient of the division of volume and number of customers) for each class. The Company's econometric modeling effort was to regress each of the two dependent variables against an array of possible independent variables and select the equation with the best fit.

By using historical economic, demographic and energy price data, listed in Chart III-B-1, as the independent variables, the Company estimated statistically valid econometric equations for each class. The Company obtained the economic and demographic data from Moody's economy.com the forecasts for which were from December 2015.

Additionally, the Company tested date as a time trend variable, actual Heating Degree Days, actual Billing Degree Days, as well as natural gas and oil prices from the Department Of Energy/Energy Information Administration (DOE/EIA).

The Company then reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company. The energy-efficiency programs that the Company analyzed for this forecast were those submitted by the Company in Docket No. 4451 in its supplemental gas filing dated May 1, 2015, the most recent data available at the time the forecast was prepared. The Company subtracted the incremental savings from the programs that are not embedded in the historical data used to derive the statistical models, because these savings are exogenous to the modeling effort.

III.B.2 Final econometric models for the Company's demand forecast

III.B.2.a Residential Heating Class

The residential heating class represents approximately 56 percent of the Company's total firm sendout to Sales and Customer Choice customers in 2015/16 (Chart III-B-3). The Company prepared the demand forecast for the residential heating class by developing separate econometric models for numbers of customers and use per customer. There is a separate model for each residential heating class (rate codes 400 and 402). The Company multiplied the results of the econometric number of customer equations by the results of the corresponding econometric use per customer equations to calculate total sales in Dth. Finally, it applied the estimated impact of the Company-sponsored energy-efficiency programs to derive the annual net sales volumes.

Base Case residential heating deliveries are forecast to increase by an average of 157 BBtu per year or 0.8% per year over the forecast period, 2015/16 through 2024/25, driven primarily by an increase in the number of customers. The forecast of retail natural gas volumes for the Sales and Customer Choice residential heating class are presented in Chart III-B-3.

The Base Case net residential heating customer count is forecast to increase by an average of 1,428 customers per year or 0.6% per year over the forecast period, 2015/16 through 2024/25. The forecast results for the Base Case residential heating customers are presented in Chart III-B-4. Customer counts for the residential heating class were modeled as a function of personal income. The monthly variation in customer counts was modeled using dummy variables within the linear regression equations to capture the seasonal decline in customer counts that occurs during the summer months and the subsequent increase during the winter months.

The average Base Case residential heating use per customer is forecast to increase by an average of 1.2 Dth/customer per year or 0.15% per year over the forecast period, 2015/16 through 2024/25. The forecast results for the Base Case residential heating class use per customer are presented in Chart III-B-5. Use-per-customer for the residential heating class was modeled as a function of degree days, employment, and natural gas price.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.2.b Residential Non-Heating Class

The residential non-heating class represents approximately 2 percent of the Company's total firm sendout to Sales and Customer Choice customers in 2015/16 (Chart III-B-3). The Company prepared the demand forecast for the residential non-heating class by developing separate econometric models for numbers of customers and use per customer. There is a separate model for each residential non-heating class (rate codes 401 and 403). The Company multiplied the results of the econometric equations for the number of customers by the results of the corresponding econometric equations for use per customer to calculate total sales. Lastly, it reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company.

Base Case residential non-heating deliveries are forecast to decrease by an average of 11 BBtu per year, or -1.6%, per year over the forecast period 2015/16 through 2024/25, driven primarily by a decrease in the number of customers. The forecast of retail natural gas volumes for the Sales and Customer Choice residential non heating class are presented in Chart III-B-3.

The Base Case net residential non-heating customer count is forecast to decrease by an average of 331 per year, or -1.6%, per year over the forecast period 2015/16 through 2024/25. The forecast results for the Base Case residential non-heating customers are presented in Chart III-B-4. Customer counts for the residential non-heating class were modeled as a function of personal income and employment. The monthly variation in customer counts was modeled using dummy variables within the linear regression equations to capture the seasonal decline in customer counts that occurs during the summer months and the subsequent increase during the winter months.

The average Base Case residential non-heating use per customer is forecast to increase by an average of 0.0 Dth/customer per year, or 0.03%, per year over the forecast period 2015/16 through 2024/25. The forecast results for the Base Case residential non-heating use per customer are presented in Chart III-B-5. Use-per-customer for the residential non-heating class was modeled as a function of degree days, personal income and time trends.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.2.c Commercial/Industrial Heating Class

The commercial and industrial heating class represents approximately 33 percent of the Company’s total firm sendout to Sales and Customer Choice customers in 2015/16 (Chart III-B-3). The Company prepared the demand forecast for the commercial and industrial heating class by developing separate econometric models for numbers of customers and use per customer. The Company multiplied the results of the econometric equations for number of customer by the results of the corresponding econometric equations for use per customer to calculate total sales. Lastly, it reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company.

There are separate models for the commercial and industrial heating classes (Sales: 404, 405, 408, 409, 412, 413, 416; Customer Choice: 406, 407, 410, 411, 414, 415, 443; Zero Capacity: Z407, Z411, Z415).

The Base Case commercial and industrial heating class demand is forecast to increase by an average of 224 BBtu per year or 1.9% per year over the forecast period 2015/16 through 2024/25, driven primarily by an increase in customer count. The forecast of retail natural gas volumes for the Sales and Customer Choice commercial and industrial heating class are presented in Chart III-B-3.

The Base Case net commercial and industrial heating class customer count is forecast to increase by an average of 385 per year, or 1.5%, per year over the forecast period 2015/16 through 2024/25. The forecast results for the Base Case commercial and industrial heating class customers are presented in Chart III-B-4. The customer counts for the commercial and industrial heating class were modeled as a function of GDP, employment, and personal income.

The average Base Case commercial and industrial heating class use per customer is forecast to increase by an average of 1.8 Dth/customer per year, or 0.4% per year, over the forecast period 2015/16 through 2024/25. The forecast results for the Base Case commercial and industrial heating class use per customer are presented in Chart III-B-5. The use-per-customer for the commercial and industrial heating class was modeled as a function of degree days, natural gas price and time trends.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.2.d Commercial/Industrial Non-Heating Class

The commercial and industrial non-heating class represents approximately 10 percent of the Company's total firm sendout to Sales and Customer Choice customers in 2015/16 (Chart III-B-3). The Company first prepared the demand forecast for the commercial and industrial non-heating class by developing separate econometric models for numbers of customers and use per customer. The Company then multiplied the results of the econometric equations for number of customer by the results of the corresponding econometric equations for use per customer to calculate total sales. Lastly, the Company reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company.

There are separate models for the commercial / industrial non-heating classes (Sales: 417, 420, 421, 424; Customer Choice: 418, 419, 422, 423; Zero Capacity: Z419, Z423).

The Commercial and industrial non-heating class demand is forecast to increase by an average of 44 BBtu per year or 1.3% per year over the forecast period 2015/16through 2024/25, driven primarily by an increase in customer count. The forecast of retail natural gas volumes for the Sales and Customer Choice commercial / industrial non-heating class are presented in Chart III-B-3.

The Base Case net commercial and industrial non-heating class customer count is forecast to increase by an average of 3 per year, or 1.3%, per year over the forecast period 2015/16 through 2024/25. The forecast results for the Base Case commercial and industrial non-heating class customers are presented in Chart III-B-4. Customer counts for the commercial and industrial non-heating classes were modeled as a function of employment, personal income, oil price, and time trends.

The average Base Case commercial and industrial non-heating class use-per-customer is forecast to decrease by an average of -2.9 Dth/customer per year, or -0.0% per year, over the forecast period 2015/16 through 2024/25. The forecast results for the Base Case commercial and industrial non-heating class use-per-customer are presented in Chart III-B-5. Use-per-customer for the commercial and industrial non-heating classes was modeled as a function of personal income, employment, degree days, and time trends.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.3.The Impact of the Energy Efficiency Programs

On November 1, 2013, the Company filed its 2014 Energy Efficiency Program Plan (the 2014 EE Program Plan) in Docket No. 4451, which was approved by the PUC on December 20, 2014. The primary goal of the 2014 EE Program Plan is to create energy (both gas and electric) and economic cost savings for Rhode Island consumers as required by the least cost procurement law, R.I.G.L. § 39-1-27.7. The goal of the natural gas energy-efficiency programs is annual reduction in usage; there are no programs that are specifically targeted toward peak reduction.

Since the Company's econometric forecast is based on historical data which does not fully incorporate the increasing penetration of the Company's energy efficiency programs in the residential and commercial and industrial sectors, the Company reviewed its historical energy-efficiency efforts and adjusted its retail demand forecast (downward) to reflect the increases in energy-efficiency efforts.

In the Company's May 1, 2015 supplemental gas filing in Docket No. 4451, Table G-1 (Summary of 2014 Target and Year End Results) reflects approved 2014 energy-efficiency programs of 160,500 MMBtu for residential and 169,463 MMBtu for commercial and industrial.

Analysis of the Company's historical energy efficiency programs shows that historical data should have embedded within annual savings of 159,249 MMBtu for residential and 158,421 MMBtu for commercial and industrial. Therefore, the Company reduced its demand forecast by the incremental savings over the historical average. For each year of the Company's forecast, 2015 and beyond, the Company's demand forecast was reduced by an incremental 1,251 MMBtu for residential and 11,042 MMBtu for commercial and industrial.

III.C. Translation of Customer Demand into Customer Requirements

In the second step of the Company's forecasting methodology, the Company uses linear regression equations of total daily sendout versus daily temperature for the most recent twelve months to calculate a reference-year by division. This serves as the most accurate way for the Company to allocate its monthly demand forecast into its future daily customer requirements. This step is used to determine the Company's normal year forecast of customer requirements over the forecast period for gas cost recovery purposes, and to determine the Company design year forecast of customer requirements over the forecast period for resource planning purposes. To perform its regression analysis, the Company used version 3.1.2 of the "R" statistical software package.[2]

To establish normal-year springboard sendout requirements, the Company developed a linear-regression equation for each of its four divisions (Providence, Westerly, Bristol & Warren Gas, and Valley Gas) using data for the reference-year period April 1, 2014 through March 31, 2015. Its regression equation uses sendout as its dependent variable and temperature as its independent variable.[3]

Through the use of the linear-regression equation, the Company is able to normalize total daily sendout. Specifically, the actual daily firm sendout is regressed against heating degree day (HDD) data as provided by its weather service vendor WSI, HDD data lagged over two days, and a weekend dummy variable. These data elements were selected for the regression analysis since these elements have been, and continue to be the major explanatory variables underlying the Company's daily sendout requirements.

The Company selected the T.F. Green International Airport weather station (KPVD) as the source of the weather data that is used as the principal explanatory variable in its regression equations. The KPVD weather station was selected because it is close to the center of the Company's service territory, on a load-weighted basis, and it is highly correlated with surrounding weather stations. Specifically, the Company used the HDD value for each 24-hour period of 10 a.m. to 10 a.m., which constitutes the gas day, and therefore, corresponds to the same daily time period of observation of the sendout data.

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[2] "R is a language and environment for statistical computing and graphics. It is a GNU project which is similar to the "S" language and environment which was developed at Bell Laboratories (formerly AT&T, now Lucent Technologies). R can be considered as a different implementation of S. There are some important differences, but much code written for S runs unaltered under R. R is available as Free Software under the terms of the Free Software Foundation's GNU General Public License in source code form. It compiles and runs on a wide variety of UNIX platforms and similar systems (including FreeBSD and Linux), Windows and MacOS." (Source: The R Project for Statistical Computing)

[3] Sendout includes both Sales and supplier service (Customer Choice) customer requirements, as well as its capacity-exempt customers.

Based on its observations of the historical relationship between total sendout and HDD, the Company chose to develop its regression equation as a segmented model, a "*regression model where the relationships between the response and one or more explanatory variables are piecewise linear, namely represented by two or more straight lines connected at unknown values: these values are usually referred as breakpoints."* (Source: "segmented: an R package to fit regression models with broken-line relationships," R News, Volume 8/1, May 2008, page 20).

Since a significant portion of the Company's sendout is due to space heating usage and space heating only occurs when average air temperatures fall below a certain level, the segmented model serves as an excellent starting point for modeling the relationship between sendout and HDD. Linear modeling of sendout is appropriate since the Company has not observed any non-linear characteristics in sendout at cold temperatures as can be seen in Chart III-C.

In the tables below, Intercept is the MMBtu sendout predicted at HDD=0, Slope1 is the MMBtu/HDD usage below the Breakpoint HDD level, Slope2 is the incremental MMBtu/HDD usage above the Breakpoint HDD level, the Standard Error is expressed in MMBtus, and the Breakpoint HDD is the HDD value at which spaceheating equipment is observed to turn on. The signs of the Slope1 and Slope2 coefficients (positive) imply that as temperatures get colder and HDD increases in value, then sendout will increase, which agrees with what the Company observes.

Based on observations of daily sendout, the Company has observed that weekday and weekend sendout requirements are different at similar HDD levels. The Company's regression equations include a second independent variable, a weekday/weekend dummy variable, set to zero for Mondays through Thursdays, 1 on Fridays and Sundays, and 2 on Saturdays. The sign of the coefficient (negative) implies that, for a given HDD level, loads will be lower on Friday-Sunday versus Monday-Thursday (weekend vs. workweek).

Finally, the Company has observed a correlation between lagged temperature and the residuals of the above equation and it added a third independent variable: the difference between HDD on day *t* and mean of the HDD on day *t-1* and day *t-2*. The differences were used in lieu of the actual lagged values to avoid correlation among the independent variables. The underlying theory of this analysis is that heating requirements increase as two consecutive days of cold weather occur, which cools down structures to a greater degree than would be experienced on a single day. The introduction of the third independent variable added another incremental improvement in the adjusted R^2 of the equations. The sign of the coefficient (negative) implies that, if a day is colder than the average of the previous two days, the increase in sendout will be somewhat lower than what would be forecast without the coefficient, and vice versa.

The table below lists the Providence regression results from 2007/08 through 2014/15.

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	39,487.0	463.4	3,568.1	-2,020.4	-527.4	6,983	0.9806	7.37
2008/09	39,516.8	468.8	3,595.2	-1,913.2	-665.7	6,217	0.9864	7.83
2009/10	38,099.3	443.6	3,832,1	-1,409.3	-710.1	6,440	0.9838	7.24
2010/11	38.961.9	543.5	3,866.8	-2,481.8	-712.0	6.823	0.9859	8.20
2011/12	39,220,4	633.6	3,876.2	-2,696.6	-818.1	6,528	0.9792	8.69
2012/13	37,170.7	639.3	4,194.6	-2,584.1	-792.9	7,065	0.9825	8.56
2013/14	39,317.6	721.5	4,096.3	-2,057.9	-755.0	7,097	0.9883	8.86
2014/15	42,967.0	844.8	3,864.4	-3,077.8	-715.7	8,569	0.9884	7.68

Segmented Regression Results for Providence sendout vs. HDD and Weekend and Lagged Delta HDD

Similarly, below are tables listing the coefficients for the final regression equation form for the Company's Westerly, Bristol & Warren, and Valley divisions.

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	1,103.6	1.3	74.4	-187.8	-6.1	261	0.9180	8.48
2008/09	1,227.1	12.2	59.1	-257.8	-9.0	196	0.9513	12.42
2009/10	1,070.2	10.3	72.7	-239.9	-11.9	191	0.9600	9.58
2010/11	1,115.6	2.3	79.3	-199.0	-9.6	174	0.9712	8.94
2011/12	1,024.5	14.4	66.3	-220.7	-15.3	190	0.9467	9.39
2012/13	1,046.9	17.0	79.7	-210.5	-16.1	187	0.9684	11.66
2013/14	1,123.9	17.7	78.5	-192.0	-15.3	193	0.9758	12.26
2014/15	1,133.1	23.6	78.9	-202.6	-16.3	197	0.9806	11.02

Segmented Regression Results for Westerly sendout vs. HDD and Weekend and Lagged Delta HDD

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	1,127.3	22.4	131.3	-149.4	-22.0	304	0.9737	8.60
2008/09	122.5	22.7	137.7	-149.9	-30.5	301	0.9780	9.65
2009/10	865.4	21.7	157.9	-109.6	-30.9	340	0.9713	9.64
2010/11	1,081.1	23.1	105.0	-135.8	-19.2	210	0.9847	8.43
2011/12	848.8	18.3	120.2	-89.9	-27.3	265	0.9619	9.31
2012/13	939.3	16.2	106.0	-65.3	-20.0	181	0.9825	8.56
2013/14	1,089.9	12.7	159.0	-63.3	-17.3	448	0.9673	6.02
2014/15	1,473.8	29.0	132.6	-105.6	-24.6	294	0.9884	7.68

Segmented Regression Results for Bristol & Warren sendout vs. HDD and Weekend and Lagged Delta HDD

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	9,844.4	-133.9	1,228.2	-1,406.4	-180.2	2,589	0.9621	5.71
2008/09	9.613.5	57.3	977.1	-1,352.5	-179.2	2,480	0.9650	8.33
2009/10	8,898.7	-7.5	1,109.0	-1,068.9	-229.6	2,266	0.9693	6.66
2010/11	10,201.6	-145.7	1,053.2	-1,420.7	-116.4	2,806	0.9481	4.37
2011/12	9,638.8	106.2	965.9	-1,176.9	-190.7	2,262	0.9556	8.50
2012/13	12,078.1	70.2	993.2	-972.7	-167.7	3,066	0.9348	9.22
2013/14	9,324.2	-23.9	1,095.7	-912.2	-155.3	3,474	0.9435	7.58
2014/15	7,950.5	51.3	1,037.7	-1,276.2	-201.7	3,238	0.9587	6.39

Segmented Regression Results for Valley sendout vs. HDD and Weekend and Lagged Delta HDD

The tables above set forth the 2014/15 springboard regression coefficients for the Company's four divisions. The functional form of the equation, in pseudo code, is then:

```
Sendout = Intercept Coefficient +
          Weekend Dummy Coefficient * Weekend Dummy Variable +
          Slope1 Coefficient * min(HDDt, Breakpoint HDD) +
          if(HDDt<=Breakpoint HDD) {0} else {(Slope1 Coefficient
            + Slope2 Coefficient) *
            (HDDt - Breakpoint HDD)} +
          Lagged Delta HDD Coefficient * (HDDt - average(HDDt-1, HDDt-2)
```

As seen above, the adjusted R-squared values for all 2014/15 regressions are all in the range of 0.96 to 0.98, and all of the t-statistics of the independent variables are greater than 2.0, except for the lagged HDD variable in the Valley Division, indicating that these variables are significant to the explanatory power of the equation.

This regression equation captures the observed characteristics of the Company's sendout requirements. The observed characteristics include the following: (1) sendout requirements are directly related to HDD; (2) sendout requirements are affected by HDDs that occur over a multi-day period; and (3) sendout requirements differ by day of the week. Thus, the Company has developed a reliable regression equation to establish the basis upon which future sendout requirements can be forecast. Using its forecast of retail demand and an appropriate set of daily HDD values for a design year, the Company can successfully plan its operational requirements to provide a low-cost, adequate and reliable supply of natural gas to its customers.

III.D. Normalized Forecast of Customer Requirements

The third step in the Company's forecasting methodology is to develop a forecast of customer requirements under normal weather conditions for its demand forecast.

III.D.1 Defining Normal Year for Ratemaking Purposes

To establish the normal year's daily HDD data for ratemaking purposes, the Company calculated the average annual number of HDD for the KPVD weather station for the ten-year period ending 31 December 2015, with an average of 5,611 HDD.

The Company then prepared a "Typical Meteorological Year" by selecting, for each calendar month, the month in the KPVD weather database that most closely approximated the ten-year average HDD and standard deviation for each month. A summary of the monthly averages for the KPVD weather site is listed in the chart below.

Month	HDD	Standard Deviation
Jan	1,108	8.9
Feb	942	7.0
Mar	803	7.6
Apr	479	6.7
May	217	5.3
Jun	43	2.5
Jul	2	0.1
Aug	7	0.4
Sep	86	3.1
Oct	359	6.7
Nov	619	7.6
Dec	946	8.0
Total	5,611	

Average Monthly HDD and Average of Monthly Standard Deviations for the T.F. Green International Airport Weather Station

III.D.2. Defining Load Attributed to Customers Using Utility Capacity

Above, the Company established the 2014/15 regression equations for total throughput in its service territory. The Company's monthly retail volumes match the wholesale volumes to within 3.6 percent; hence, the Company has adequately captured all customer volumes. For the third step of the Company's forecasting methodology set forth in Section III.A, above, the Company then allocated the monthly retail volumes to the daily level based on the 2014/15 reference-year regression equations, using normal year HDD, to yield the forecast of customer requirements under normal weather conditions for its demand forecast, based on a 365-day year.

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Heating Season	24,250	24,544	25,057	25,446	25,758	25,970	26,026	26,387	26,624	27,004
Non-Heating Season	10,517	10,777	10,982	11,141	11,233	11,285	11,465	11,580	11,754	11,754
Total	34,767	35,321	36,040	36,588	36,991	37,255	37,491	37,967	38,378	38,758
Per-Annum Growth		554	719	548	403	264	236	476	411	379
Per-Annum Growth (%)		1.6 %	2.0 %	1.5 %	1.1 %	0.7 %	0.6 %	1.3 %	1.1 %	1.0 %

Base Case Normal Year Customer Requirements for Capacity Planning (BBtu)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Heating Season	24,212	24,488	25,216	25,745	26,069	26,155	26,063	26,387	26,688	27,129
Non-Heating Season	10,464	10,832	11,110	11,276	11,312	11,296	11,461	11,616	11,828	11,828
Total	34,676	35,320	36,326	37,021	37,381	37,451	37,525	38,003	38,516	38,957
Per-Annum Growth		644	1,005	695	361	70	74	478	513	441
Per-Annum Growth (%)		1.9 %	2.8 %	1.9 %	1.0 %	0.2 %	0.2 %	1.3 %	1.3 %	1.1 %

High Case Normal Year Customer Requirements for Capacity Planning (BBtu)

III.E. Planning Standards

In the fourth step of the Company's forecasting methodology, the Company determines the appropriate design-day and design-year planning standards to develop a least-cost, reliable supply portfolio over the forecast period.

III.E.1 Normal Year for Standards Purposes

To establish the design year's daily HDD data, the Company began by calculating the average annual number of HDDs for KPVD (T.F. Green International Airport weather station) for the forty calendar years 1976 through 2015, with an average of 5,596.6 HDD and a standard deviation of 358.6 HDD.

The Company then prepared a "Typical Meteorological Year" by selecting, for each calendar month, the month in the KPVD weather database that most closely approximated the average HDD and standard deviation for each month.

III.E.2. Design Year and Design Day Planning Standards

The Company's planning standards represent the defined weather conditions and consequent sendout requirement that must be met by the Company's resource portfolio. The Company's design year and design day standards are listed in the chart below.

Element	Value
Design Year HDD	6,280
Frequency of Occurrence	1 / 35.28 years
Design Day HDD	68
Frequency of Occurrence	1 / 98.86 years

Design Year and Design Day Criteria

As described below, the Company's analysis of the design year and design day standards demonstrate that these standards are appropriate.

III.E.2.a. Design Day Standard

The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. In this filing, the Company defines its design day standard at 68 HDD with a probability of occurrence of once in 98.86 years, as a result of its on-going review of planning standards.

The Company established its design day standard using a three-step process. First, the Company performed a statistical analysis of the coldest days recorded over a historical period. Second, the Company conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design day demand versus the cost to customers of experiencing service curtailments. Third, the Company identified a design-day standard that would maintain reliability at the lowest cost.

To perform the statistical analysis necessary to identify the appropriate design-day standard, the Company used recorded daily HDD values based on observations at the KPVD weather site for the split years 1975-76 through 2014-15. Specifically, the Company selected the coldest day of each of the most recent 40 heating seasons reflected in the KPVD weather data. The Company used EDD data from the KBOS weather site because this site is centrally located within the Company's service territory. The Company found that these 40 data points fell within a normal distribution with an average of 55.43 HDD and a standard deviation of 5.42 HDD.

In its design day standard, the Company examines the cost of potential customer curtailments through a cost-benefit analysis. Chart III-E-1 shows the cumulative probability distribution and the frequency of occurrence of HDD levels greater than the mean peak day. Chart III-E-1 shows the cumulative probability distribution and the frequency of occurrence of HDD levels greater than the mean peak day. Chart III-E-1 also shows, given the current peak period heating coefficient of 5,456.13 MMBtus/HDD, the supply (Delta Supply) required at these levels. The Company then translated these supply levels into the "Equivalent Number of Customers" that would be represented by a shortfall at a given HDD level.[4]

In the event of a service disruption, there are several types of damages that customers could experience. For example, the Company's residential customers would potentially incur re-light costs and freeze-up damages. The Company's commercial/industrial customers would potentially incur economic damages associated with the loss of production on the day of the event (which is further documented in Section III.E.2.b - Design Year Standard).

For this filing, the Company priced its potential re-light costs based on its experience in outage restoration at $1,069/customer.

[4] The Company determined the equivalent number of customers using the following formula: Delta Supply/[(Heating Increment/Number of Customers)*HDD].

For this filing, the Company updated its 2008 cost estimate for freeze-up damages from Marsh & McLennan. According to Marsh & McLennan, in 2008, the average cost estimate of remodeling is $20,000/customer. The Company applied the 2014 U.S. Construction Price Deflator to this value to arrive at a new figure of $20,897/customer. The Company has made the assumption that, in the event of freeze-up damages, only a portion of a residence would require remodeling, and the Company's analysis considers three levels of resulting damages: 25%, 50%, and 75%. Accordingly, the Company multiplied the freeze-up damages figure by two to represent the cost of a full remodel, so that the midpoint of the damages would align with the average cost estimate of $20,897/customer.

Given the ratio of C&I customers to the total number of customers at year-end 2015, the Company divided the "Equivalent Number of Customers" into the number of residential and C&I customers. For the C&I customers, the Company computed the cost of the service disruption by multiplying the ratio of affected customers by the total number of C&I customers by the estimated cost of one day's service disruption to the Company's entire group of C&I customers. Since the actual number of residential customers that would suffer freeze-up damage in a real emergency is unknown, the Company analyzed three levels of damages assuming 25 percent, 50 percent, and 75 percent of potentially affected residential customers suffer damages (as mentioned in the previous paragraph). The computed values for these three scenarios of probability-weighted costs of damages are presented in Chart III-E-2 and are shown graphically in Chart III-E-3.

Chart III-E-4 takes the HDD levels and the associated Delta Supply to estimate the costs associated with maintaining adequate deliverability at the HDD levels. The low-upgrade cost scenario is based on the cost of adding LNG vaporization capacity and the high-upgrade cost scenario is based on the cost of adding 365-day interstate pipeline service (with many other potential options falling in between). This is shown graphically in Chart III-E-5.

III.E.2.a.3 Design Day Selection

In Chart III-E-5, the cost of maintaining adequate throughput capacity and the benefit of avoiding damage costs that would be incurred in relation to customer premises are compared. The intersection of the curves sets a range for design day planning purposes from approximately 64.0 to 70.4 HDD with a midpoint of 66.8 HDD. Thus, the Company's design day standard of 68 HDD is within the range of values based on cost and benefit. Chart III-E-1 indicates that the frequency of occurrence of the Company's design day standard is once in 98.86 years.

III.E.2.b. Design Year Standard

In this filing, the Company defines its design year standard as 6,280 HDD with a probability of occurrence of once in 35.28 years.

The Company maintains a design year standard for planning purposes to identify the amount of seasonal supplies of natural gas that will be required to provide continuous service under all reasonable weather conditions. If the Company were to have a shortfall in supply during the winter season, the amount of supply in deficit can be translated into an equivalent number of customers whose service would be disrupted for more than one day. For a supply disruption of a multi-day duration, service would be curtailed on a priority basis and would likely fall on commercial and industrial establishments before affecting the residential sector, since supply to the residential sector is more likely to involve health and personal safety. To establish an estimated annual level of HDD, for which it should plan, the Company compared the benefit of maintaining an adequate quantity of natural gas supply under all reasonable weather conditions to the probability-weighted cost of losses that might occur if supplies are not adequate.

The Company has established its design-year standard using a three-step process. First, the Company performed a statistical analysis of annual EDD data recorded over a historical period. Second, the Company conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design-year demand versus the cost to customers of experiencing service curtailments. Third, the Company identified a design-year standard that would maintain reliability at the lowest cost.

To complete the first step in the process of determining its design-year standard, the Company computed the calendar year totals for HDD at the KPVD weather site for the forty years 1976 through 2015, and calculated the mean (5,596.6 HDD) and standard deviation (358.6 HDD). To evaluate the design-year standard, the Company analyzed the impact of planning over a range of annual HDD values from the mean value to 1,200 HDD greater than the mean.

To complete the second step in the development of the design-year standard, the Company performed a cost-benefit analysis by examining the cost of potential customer curtailments in relation to the cost of maintaining adequate supplies to meet the design-year standard. Because a failure to perform on a seasonal basis would mean that adequate supplies were not available to meet customer needs, the Company views the cost of failure to deliver as the economic penalty within the service territory associated with the need to curtail gas sales for a period of time. Service would be rationed among the Company's customers for a number of days in order to husband any remaining gas supplies. The Company estimated the potential losses based on the product of the potential economic cost per day of interruption, times the number of days of interruption.

To calculate this estimate of potential losses, the Company determined the average Gross State Product per day (GSP/day) for 2014 from data from the Bureau of Economic Analysis. The economic cost to the Company's customer base per day was then calculated on the basis of the total GSP/day. First, the value for the GSP/day for the Company's service territory was estimated by multiplying the GSP/day by the ratio of the number of employees within the service territory to the total number of employees within the state, based on 2015 employment estimates from Moody's. Then, the value for the GSP/day for the Company's customer base was estimated by multiplying the GSP/day figure for its service territory by the Company’s estimated market share of natural gas in relation to all fuel types in its service territory.

To determine the number of days of interruption that a supply shortfall would represent, the Company analyzed its supply requirements at various HDD levels, assigned requirements to supply sources and, using 5,596 HDD as the baseline, estimated when supply sources would be in deficit, as well as the quantity and duration of such deficit.

The Company established a baseline of the normal annual HDD (5,596.6) and then determined sendout requirements for the split year 2015/16 by assigning all sendout requirements below 182,787 MMBtus/day to pipeline supply; all requirements between 182,787 and 221,543 MMBtus/day to underground storage supplies; and all requirements above 221,543 MMBtus/day to supplemental resources. The Company then analyzed the sendout requirements for HDD levels of 5,700 to 6,900 on 100 HDD increments. The Company computed these HDD scenarios by multiplying each of the days of its normal HDD days by the ratio of the desired annual total to 5,596.6 HDD. Using the same method of assignment of supply sources, the Company determined the annual shortfalls by supply source (Chart III-E-6).

Chart III-E-7 shows that the timing of when the shortfalls occur varies among the supply sources. Pipeline shortfalls occur late in the heating season when alternative supplies would be fairly easy to arrange. The underground storage and supplemental-resource shortfalls occur during the heating season when arranging alternative supplies would be more difficult. Chart III-E-8 summarizes the HDD levels, the probabilities of occurrence, and the shortfall by supply type.

Analysis indicates that sendout for the Company during the heating season was 58 percent residential and 42 percent commercial and industrial. Therefore, the total daily shortfall of underground storage and supplemental supplies at all HDD levels in this study can be assigned to C&I customers. For each forecast day under each HDD scenario, the daily sendout requirement was multiplied by 42 percent to derive the C&I portion. If the day had a supply shortfall, the shortfall value was divided by the C&I requirement to derive that day's fractional amount of the Company's C&I customers that would suffer curtailment. Summing all of these values for a given HDD scenario, the Company determined the total number of day-equivalents of interruption. This value is less than or equal to the number of calendar days during which interruption occurred since not all days will have 100 percent interruption. Multiplying the number of day-equivalents by the GSP/day for the C&I customer base yields an estimate of the economic damage that would occur. Chart III-E-9 lists the HDD levels, the probabilities of occurrence, the days of interruption, the cost of the interruption, the probability-weighted cost of the interruption and the quantity of interrupted winter supply (via pipeline capacity from the Marcellus Basin).

There are two damages scenarios presented here: one where 25 percent of the C&I establishments are actually affected, and one where 75 percent of the establishments are affected. Chart III-E-9 also sets forth two scenarios of capacity that the Company acquires on behalf of its customers to avoid such damages (traditional short-haul capacity plus market-area storage and traditional long-haul capacity). Chart III-E-10 demonstrates that a planning range of 6,130 to 6,410 HDD is appropriate.

III.E.2.b.3. Design Year Selection

As a result of this analysis, the Company has determined that a design year standard of 6,280 HDD is an appropriate level. Chart III-E-8 indicates that the frequency of occurrence of the Company's design-year standard is once in 35.28 years.

III.E.2.c. Specification of Daily Design Year HDD

To generate the daily HDD values for its design year, the Company scaled the daily values for its normal year by the ratio of the annual normal year total to the annual design year total, making any minor adjustment necessary to ensure the peak day of the design year equaled the Company's design day standard.

III.F. Forecast of Design Year Customer Requirements

In the fifth and final step of the Company's forecasting methodology set forth in Section III.A, above, the Company uses the applicable design day and design-year planning standards to determine the design day and design-year sendout requirements. To accomplish this, the Company combines the springboard equations, which are derived from the sendout regression analysis, with its normal year daily HDD pattern and its design year daily HDD pattern to yield two springboard year estimates of normal year and design year daily customer requirements. Below are the resulting design year requirements for the demand forecast.

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Heating Season	26,510	26,833	27,397	27,824	28,166	28,399	28,460	28,857	29,117	29,534
Non-Heating Season	11,530	11,815	12,041	12,215	12,315	12,372	12,570	12,696	12,886	12,886
Total	38,041	38,648	39,438	40,039	40,482	40,771	41,030	41,553	42,004	42,420
Per-Annum Growth		608	789	602	442	290	259	523	451	416
Per-Annum Growth (%)		1.6 %	2.0 %	1.5 %	1.1 %	0.7 %	0.6 %	1.3 %	1.1 %	1.0 %

Base Case Design Year Customer Requirements (BBtu)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Heating Season	26,469	26,775	27,575	28,155	28,511	28,604	28,503	28,857	29,188	29,671
Non-Heating Season	11,472	11,876	12,180	12,363	12,402	12,384	12,566	12,736	12,968	12,968
Total	37,941	38,651	39,755	40,518	40,913	40,988	41,069	41,593	42,156	42,639
Per-Annum Growth		709	1,104	763	395	75	80	524	563	483
Per-Annum Growth (%)		1.9 %	2.9 %	1.9 %	1.0 %	0.2 %	0.2 %	1.3 %	1.4 %	1.1 %

High Case Design Year Customer Requirements (BBtu)

III.G. Capacity Exempt Customer Requirements

Capacity exempt customers are transporters on the Company's distribution system but the Company does not plan for their resources outside of the citygate. Their supply is provided by third-party marketers. The Company's forecasting process also includes a forecast of capacity-exempt load for distribution system planning purposes (see table below).

Capacity-Exempt Load Summary (Dth)
Base Case Forecast

Normal Year

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
HS	4,216,642	4,264,577	4,324,278	4,404,198	4,430,065	4,417,431	4,422,163	4,436,803	4,444,087	4,457,677
NHS	3,573,005	3,593,426	3,617,044	3,623,008	3,629,242	3,607,169	3,610,568	3,615,038	3,633,699	3,633,699
Total	7,789,646	7,858,003	7,941,322	8,027,206	8,059,308	8,024,600	8,032,731	8,051,841	8,077,786	8,091,376
PA Growth		68,357	83,319	85,884	32,102	-34,708	8,131	19,110	25,945	13,590
Pct Growth		0.9%	1.1%	1.1%	0.4%	-0.4%	0.1%	0.2%	0.3%	0.2%

Design Year

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
HS	4,704,999	4,756,496	4,821,179	4,908,114	4,935,986	4,922,083	4,927,063	4,942,844	4,950,462	4,965,293
NHS	3,919,930	3,942,431	3,968,322	3,974,854	3,981,681	3,957,464	3,961,178	3,966,070	3,986,522	3,986,522
Total	8,624,929	8,698,927	8,789,502	8,882,969	8,917,667	8,879,547	8,888,241	8,908,914	8,936,984	8,951,815
PA Growth		73,997	90,575	93,467	34,698	-38,120	8,694	20,673	28,070	14,831
Pct Growth		0.9%	1.0%	1.1%	0.4%	-0.4%	0.1%	0.2%	0.3%	0.2%
Peak Day (Dth)	60,767	61,879	62,595	62,580	62,881	62,959	63,962	64,154	63,990	63,322

Capacity-Exempt Customer Requirements (MMBtu)

Section IV
Resource Portfolio
Design

IV. Design of the Resource Portfolio

IV.A. Portfolio Design

To meet load requirements under design weather conditions, the Company maintains a resource portfolio consisting of pipeline transportation, underground storage, and supplemental resources. By resource type, the Company's currently available resources to meet deliverability requirements on the peak day are as follows:

	Available Resources 2015/16 (Citygate quantity in Dth)
Pipeline Transportation	182,787
Underground Storage	38,756
Peaking Resources	158,000
TOTAL	**379,543**

Having established its forecast of design year customer requirements, the Company evaluates its existing resource portfolio to determine if it has adequate resources over the forecast period. As part of this evaluation, the Company reviews the possible strategies for meeting customer requirements using the existing resource portfolio in a variety of circumstances. Using the SENDOUT® model (described below), the Company is able to: (1) determine the least-cost portfolio that will meet forecasted customer demand, and (2) test the sensitivity of the portfolio to key inputs and assumptions, as well as its ability to meet all of the Company's planning standards and contingencies. Based on the results of this analysis, the Company is able to make preliminary decisions on the adequacy of the resource portfolio and its ability to meet system requirements over the longer term.

Since 1996, the Company has been using the SENDOUT® model developed by New Energy Associates, now Ventyx, as its primary analytical tool in the portfolio design process. The SENDOUT® model is a linear-programming optimization software tool used to assist in evaluating, selecting and explaining long-term portfolio strategies. SENDOUT® has several advantages over previous models. For instance, there is no limit to the number of resources that can be defined. This allows the Company to model its resources more realistically and to receive more meaningful output. Second, the model allows the Company to examine the effect of various contracts on the total portfolio cost.

In that regard, the Company utilizes the SENDOUT® model to determine the best use of a given portfolio of supply, capacity and storage contracts to meet a specified demand. That is, it can solve for the dispatch of resources that minimizes the cost of serving the specified demand given the existing resource and system-operating constraints. The model dispatches resources based on the lowest variable cost to meet demand, assuming that demand charges are fixed.

IV.B Analytical Process and Assumptions

For the purpose of preparing this Long-Range Plan filing, the Company analyzed its design year and a normal year demand under base-case and high-case growth scenarios as described in Section III. In addition, the Company analyzed a cold-snap scenario using the Company's existing resource portfolio. The examination of these various scenarios enables the Company to test the adequacy and flexibility of the resource portfolio.

To perform the analysis of these three scenarios, the Company incorporated several key assumptions. First, the Company assumed that, throughout the forecast period, there is no change in the Company's service obligation to plan for the capacity requirements of firm, non-grandfathered capacity-exempt customers. Therefore, for the purposes of this filing the Company has included both Firm Sales and Firm Transportation customers that utilize the Company's firm capacity in the SENDOUT® model. Second, the Company's analysis assumes that all transportation and storage contracts expiring during the forecast period are renewed at the same cost, the same volume and with the same operating characteristics. Third, the Company assumed that its LNG supply contracts as well as its citygate supply arrangements expire on the contract termination date, and are therefore not assumed to be available after the respective date.

IV.C. AvailableResources

This section describes the Company's current resource portfolio as well as the Company's expected resource portfolio given certain portfolio decisions the Company has made, and also discusses any modifications that the Company anticipates making to the portfolio during the forecast period to meet sendout requirements. As discussed below, to meet design day and design-year sendout requirements, the Company's resource portfolio is composed of the following categories of available resources: (1) transportation contracts; (2) underground storage contracts; and (3) peaking resources. In addition, a discussion of the Company's Natural Gas Portfolio Management Plan (NGPMP) is included. Chart IV-C-2 is a schematic of the Company's transportation and underground storage contracts effective November 1, 2015. Chart IV-C-3 is a table listing and description of each transportation and storage contract in the Company's resource portfolio as of November 1, 2015.

IV.C.1 Transportation Contracts

The Company has capacity entitlements on multiple upstream pipelines that allow for the delivery of gas to its citygates in Rhode Island. These contracts provide access to domestic production fields as well as liquid trading points that afford the Company a level of operational flexibility to ensure the least-cost dispatch and reliable delivery of gas supplies. In general, the Company's transportation agreements provide: (a) transportation to the Company's citygates for Gulf Coast, Market Area and Canadian supplies; (b) transportation for underground storage withdrawal and injections; and (c) the flexibility to meet any balancing and no-notice requirements.

The Company's pipeline capacity contracts fall into three primary categories. First, the Company has contract entitlements to long-haul capacity that is used to transport gas from production areas in the Gulf of Mexico as well as the Northeast Market Area to underground 7storage facilities located in central Pennsylvania, New York and West Virginia, and to the Company's Rhode Island citygates. Second, the Company has contract entitlements to short-haul capacity that is used to transport gas from underground storage fields to the Company's Rhode Island citygates. These short-haul capacity entitlements are also used to ensure the deliverability of non-storage supplies to the Company's citygates, when the capacity is not being used to transport underground storage supplies. Third, the Company has entitlements to short-haul capacity that is used to transport gas sourced in Canada to the Company's Rhode Island citygates. The Company's transportation contract entitlements are described below:

Algonquin Gas Transmission Company: The Company has total firm capacity entitlements of 152,705 MMBtus/day on the Algonquin Gas Transmission (Algonquin) pipeline system. Because Algonquin is not directly connected with any production or underground storage area, the Company also holds firm capacity entitlements on interstate pipelines upstream of the Algonquin system for transport to interconnects with the Algonquin system, for delivery to the Company's distribution system.

Columbia Gas Transmission, LLC: The Company has total firm capacity entitlements of 50,000 MMBtus/day on the Columbia Gas Transmission, LLC (Columbia) pipeline system. The Columbia system is a large network spanning from the Gulf Coast to the Midwest, Mid-Atlantic and Northeast. The Company's contracts provide for specific entitlements at four different points within the system which interconnect with other major pipelines. The receipt point at Maumee, Ohio (30,000 MMBtus/day) interconnects with Western supply, Broad Run, West Virginia (10,000 MMBtus/day) interconnects with Tennessee Gas Pipeline (Tennessee), Eagle, Pennsylvania (3,600 MMBtus/day) interconnects with Texas Eastern Transmission, L.P. (Texas Eastern), and Downingtown, Pennsylvania (3,855 MMBtus/day) interconnects with Transcontinental Gas Pipe Line Company (Transco). All of the Company's transportation contracts with Columbia deliver into the interconnection with Algonquin at Hanover, New Jersey.

Dominion Transmission Incorporated: The Company has total firm capacity entitlements of 7,922 MMBtus/day on the Dominion Transmission Incorporation (Dominion) pipeline system. A portion (537 MMBtu/day) of the capacity originates at the interconnection with Texas Eastern at Oakford, Pennsylvania and delivers into Texas Eastern at Leidy, Pennsylvania. The remaining capacity (7,385 MMBtu/day) originates at Dominion storage fields and delivers into either the M3 Market Area on Texas Eastern or into the Zone 4 Market Area at Ellisburg, Pennsylvania into Tennessee.

Iroquois Gas Transmission System: The Company has total firm capacity entitlements of 1,012 MMBtus/day on the Iroquois Gas Transmission (Iroquois) pipeline system. Firm supplies from Dawn, Ontario are transported via the Iroquois system from the interconnect at Waddington, New York to the Tennessee interconnect at Wright, New York.

National Fuel Gas Supply Corporation: The Company has total firm capacity entitlements of 1,177 MMBtus/day on the National Fuel Gas Company (National Fuel) pipeline system. This firm capacity is used to transport gas from the interconnect with Texas Eastern at Holbrook, Pennsylvania to the interconnection with Transcontinental Gas Pipe Line Company (Transco) at Wharton, Pennsylvania.

Tennessee Gas Pipeline: The Company has total firm capacity entitlements of 68,838 MMBtus/day on the Tennessee Gas Pipeline (Tennessee) system to its citygates. Tennessee originates in the Gulf of Mexico on three separate pipeline segments: the 100 leg, the 800 leg, and the 500 leg. In addition, the Tennessee system is divided into six market Zones, from Zone 0 and Zone 1 in Texas and Louisiana where the three legs merge into the Tennessee mainline to Zone 6 in New England. The Company's contract entitlements consist of transport volumes from Zone 0 and Zone 1 of up to 40,935 MMBtus/day to the Company's citygates located in Zone 6 and to the Company's storage fields located in Zone 4. From the Zone 4 storage market area, the Company's contract entitlements consist of transport volumes of up to 10,836 MMBtu/days to the Company's citygates. From the interconnection at Niagara in Zone 5, the Company's contract entitlements transport volumes of up to 1,067 MMBtus/day to the Company's citygates. From the interconnect at Wright, New York with Iroquois in Zone 5, the Company's contract entitlements transport volumes of up to 1,000 MMBtus/day to the Company's citygates. Finally, the Company has contract entitlements of up to 15,000 MMBtus/day from Dracut, Massachusetts located in Zone 6 to the Company's citygates.

Texas Eastern Transmission, L.P.: The Company has total firm contract entitlements of 64,975MMBtus/day of capacity directly connected to supply and storage areas on the Texas Eastern Transmission, L.P. pipeline system (Texas Eastern). Texas Eastern is a large network stretching from South Texas to New Jersey, comprised of a production area and a market area. The production area, south of Arkansas and Kosciusko, Mississippi, is divided into four access areas: South Texas (STX), East Texas (ETX), West Louisiana (WLA) and East Louisiana (ELA). The Company's contracts provide for specific entitlements within and through each access area. The market area is divided into three market zones beginning with the access-area boundary: Arkansas-Mississippi, north to the Tennessee-Kentucky border and the Ohio River (M1), continuing north to the Pennsylvania – New York storage fields and market area production region (M2), and from storage fields to the eastern terminus in New Jersey (M3). Contract entitlements are expressed in terms of these market zones. All of the Company's transportation contracts with Texas Eastern deliver into Texas Eastern Market Areas or the interconnection with Algonquin at either Lambertville or Hanover, New Jersey.

TransCanada PipelineLtd.: The Company has total firm capacity entitlements of 1,012MMBtus/day on the TransCanada Pipeline (TransCanada) system. The capacity path originates at the interconnection with Union Gas Limited (Union) at Parkway, Ontario and delivers into Iroquois at Waddington, New York.

<u>Transcontinental Gas Pipe Line Company, LLC</u>: The Company has total firm capacity entitlements of 1,240 MMBtus/day on the Transcontinental Gas Pipe Line Company, LLC (Transco) pipeline system. The capacity path originates at the interconnection with National Fuel at Wharton and delivers into Algonquin at Centerville, NJ.

<u>Union Gas Limited</u>: The Company has total firm capacity entitlements of 1,025 MMBtus/day on the Union Gas (Union) pipeline system. The capacity path originates at Dawn, Ontario and delivers into TransCanada at Parkway, Ontario.

IV.C.2 Underground Storage Services

Underground storage capacity plays a critical role in the Company's ability to minimize costs. The Company's underground storage assets provide the Company with the ability to meet winter-season loads, while avoiding the expense of adding 365-day long-haul transportation capacity. Underground storage supplies also allow the Company to serve peak-period requirements with off-peak priced gas supply in order to manage minimum-take requirements and short-term fluctuations in demand. By using long-haul capacity to fill storage, the Company is able to use those resources at a high load factor. Lastly, underground storage greatly enhances the flexibility of the portfolio, allowing the Company to manage major fluctuations in weather from day to day. One underground storage service of note, within the Company's portfolio, is its storage swing service under Rate Schedule Firm Storage Market Area (FSMA) on Tennessee. This storage swing option is designed to allow a daily imbalance tolerance that is equal to the Maximum Daily Withdrawal Quantity (MDWQ) as stated in the Company's storage contract (10,920 MMBtus/day). The imbalance is treated as an automatic storage injection or withdrawal under the specific contract and assessed applicable charges under the FS-MA contract. The Company has elected one of its firm storage contracts (FS-MA #501) as a storage swing option. This swing option provides vital flexibility to the Company's portfolio in order to manage daily fluctuations in load and avoid imbalance charges and/or penalties. A summary of the Company's storage services are provided in the table below:

Pipeline Company	Rate Schedule	MDWQ	MSQ	MDIQ
Columbia	FSS	2,545	203,957	2,545
Dominion	GSS-TE	14,337	1,376,324	7,647
Dominion	GSS	11,403	1,039,304	5,774
Tennessee	FS-MA (Storage Swing)	10,920	605,343	4,036

Pipeline Company	Rate Schedule	MDWQ	MSQ	MDIQ
Tennessee	FS-MA	10,249	210,000	1,400
Texas Eastern	SS-1 Storage	14,802	1,240,023	6,374
Texas Eastern	FSS-1 Storage	944	56,640	291
TOTAL		**65,200**	**4,731,591**	**28,067**

IV.C.3 Peaking Resources

In addition to interstate pipeline and underground storage resources, the Company utilizes peaking resources to meet its design requirements. Peaking supplies are a critical component of the resource mix in that these supplies provide the Company with the ability to respond to fluctuations in weather, economics and other factors driving the Company's sendout requirements, particularly on the coldest days.

IV.C.3.a LNG Facilities

The Company maintains three on-system LNG facilities. The Company's on-system supplemental facilities are distributed strategically across the service territory, which enhances service reliability and provides a source of supply for the entire distribution system. Chart IV-C-4 shows the location of these facilities. Because these resources can be brought on line quickly, these plants can be used to meet hourly fluctuations in demand, maintain deliveries to customers and balance pressures across portions of the distribution system during periods of high demand. These supplemental volumes are the supplies that must be available to the Company's distribution system to ensure service to customers when the Company has exhausted its available pipeline supplies. It is the Company's practice to have its supplemental storage facilities full as of December 1st of each year.

The Company's LNG storage and vaporization capacities are summarized in the table below:

Location	Facility Type	Maximum Vaporization [MMBtu/day]	Gross Storage Capacity [MMBtu]
Providence	LNG	95,000	600,000
Exeter	LNG	18,000	202,000
Cumberland	LNG	32,000	86,000

IV.C.3.b LNG Refill Contracts

The availability of LNG to refill the Company's local storage tanks throughout both the off-peak and peak season is a reoccurring necessity given the construct of the Company's current resource portfolio. During the 2015 off-peak period, the Company had one agreement in place with GDF Suez for liquid refill. In the 2015/16 peak period, the Company also had one agreement in place with GDF Suez for liquid refill. The details of these arrangements are summarized in the table below:

Contract	Description	MDQ (MMBtus)	ACQ (MMBtus)
GDF SUEZ NAESB	Firm Liquid Service (2015 Off-Peak Season)	6,000	900,000
GDF SUEZ NAESB	Firm Liquid Service (2015/16 Peak Season)	3,000	125,000

In addition, as has been the practice for the last several years, the Company has contracted for trucking arrangements in order to guarantee the availability of both trailers and drivers to truck the LNG from the source point to the Company's LNG facilities throughout the year.

IV.C.3.c Citygate Delivered Supply

The Company also contracts for citygate delivered supplies to meet customer requirements during the peak season. These supplies represent additional resources that are needed over and above the available assets in the Company's portfolio. These resources allow for a certain volume to be called upon on a daily basis, coupled with a seasonal delivery limitation, and are delivered to the Company's citygates by a third party. For the 2015/16 winter season, the Company contracted for a total of 13,000 dt/day and up to 420,000 dt/season of citygate delivered supplies. The purchasing of citygate delivered supplies minimizes the cost of the resource portfolio because the

Company is able to avoid annual demand charges for capacity. However, the level at which the Company can depend on such resources varies due to a number of factors, including but not limited to: current market conditions, capacity availability, and supply availability. As such, the Company will ultimately fill unserved needs through the addition of long-term capacity contracts or other long-term arrangements.

IV.C.4. Pending Portfolio Additions

The development of new horizontal drilling and well completion techniques has enabled the economic extraction of natural gas from shale formations and has resulted in abundant domestic supplies of natural gas. However, the Company will not fully realize the benefits of these inexpensive supplies without sufficient pipeline capacity to transport the gas to market. As discussed previously, there are two interstate pipelines serving the Company's distribution system; Algonquin and Tennessee. Both of these pipelines are fully subscribed. While gas supply from the south and west has grown significantly, the Company has experienced significant declines in the availability of supply to feed its pipeline capacity that originates in the northeast (i.e capacity on Algonquin with a receipt point of Beverly, MA and capacity on Tennessee with a receipt point of Dracut, MA). Offshore supplies from Sable Island and Deep Panuke have dramatically declined and onshore supplies have not materialized as once projected. Furthermore, with the increased global demand for LNG, deliveries to the Northeast have also declined dramatically and prices have increased greatly. In addition, GDF Suez continues to be the primary supplier of LNG to the region. GDF Suez was previously regulated by the Federal Energy Regulatory Commission (FERC) until a 2008 order, whereby FERC granted GDF's request that the sale of LNG no longer be subject to FERC jurisdiction. As a result, the price GDF Suez can charge for service is no longer regulated and nor does GDF Suez have the obligation to offer LNG for sale. Therefore, it has become more difficult and more expensive to acquire gas supply delivered into the Company's northeast pipeline capacity and to acquire LNG to fill its regional storage tanks.

To address the changing gas supply landscape and to ensure its ability to reliably serve existing customer requirements as well as forecasted growth, the Company has developed and implemented a multi-pronged approach that includes incremental interstate pipeline capacity, as well as long-term LNG supply and liquefaction services.

IV.C.4.a Pending Pipeline Transportation Agreements

- *Algonquin Crary Street Project (Crary Street Project)*
  The Company has entered into a Precedent Agreement with Algonquin for firm natural gas transportation capacity on its existing Manchester Street lateral off of the Algonquin mainline to the new meter station. The new meter station will be constructed and owned by Algonquin, and will be sized to move up to 96,000 dth/day. This new gate station will provide enhanced reliability for the Company's distribution system as it will allow for a new feed into the system at higher pipeline pressures. Furthermore, during the shoulder seasons, it will

eliminate the need to rely on LNG to maintain system pressures before it would be otherwise be needed to meet customer load. Algonquin will provide service under its AFT-CL Rate Schedule. This project has an expected in service date of November 1, 2016.

- *Algonquin Incremental Market Expansion (AIM Project)*
  The Company has entered into a Precedent Agreement for 18,000 MMBtu/day as part of the AIM Project for an initial term of fifteen years with service expected to commence on November 1, 2016. The AIM Project will provide the Company with the opportunity to secure a cost effective, domestically produced source of supply at Ramapo, NY to meet current customer requirements. The Company's 18,000 dth/day of AIM capacity represents the sum of the Company's existing HubLine and East-to-West capacity on Algonquin. As of the in-service date of the AIM Project, these existing contracts will terminate. Thus, the Company is not acquiring incremental citygate delivered capacity but rather is, in effect, replacing an illiquid receipt point at Beverly, Massachusetts with a more liquid receipt point at Ramapo, New York, the interconnect with Millennium Pipeline.

- *Millennium Expansion Project (Millennium Project)*
  The Company has entered into a Precedent Agreement for 9,000 MMBtu/day as part of the Millennium Project for an initial term of fifteen years with service expected to commence on November 1, 2017. The Company's 9,000 dth/day of Millennium capacity represents half of the Company's AIM Project volume. The Millennium Pipeline begins in Independence, New York (Steuben County, in Southwestern New York) and terminates in Buena Vista, New York (Rockland County, near the Hudson River, just north of the New Jersey border). It passes through southern New York, just north of the Pennsylvania border and accesses gas supplies from the prolific Marcellus Shale production area in northeastern Pennsylvania. The Millennium Pipeline has interconnections with several storage fields and a number of pipelines, including: National Fuel; Columbia Gas Transmission; Dominion Transmission, Inc.; the Laser NE Gathering System, a Marcellus Shale gathering system in Northeastern Pennsylvania owned by an affiliate of Transcontinental Gas Pipeline; the Bluestone Gathering System, a fully owned subsidiary of DTE Energy; and the Central New York Oil and Gas (CNYOG) system which operates the Stagecoach Storage facility and a pipeline that connects the Millennium system with the Tennessee 300 Line and the Transco Leidy Line. The Millennium system currently has approximately 821,000 MMBtu per day of primary firm delivery point capacity to Algonquin at Ramapo, New York. The Millennium Expansion Project is designed to expand facilities to bring an additional 200,000 dth/day of East Pool supplies to Millennium's interconnection with Algonquin at Ramapo. The Millennium Project will provide the Company with the opportunity to directly secure a cost effective, domestically produced source of supply.

- *Tennessee Gas Pipeline Northeast Energy Direct Project (NED Project)*
  The Company has entered into a Precedent Agreement for 35,000 MMBtu/day as part of the NED Project for an initial term of twenty years with service expected to commence on November 1, 2018. The NED Project will provide the Company with the opportunity to secure a cost effective, domestically produced source of supply at Wright, NY to meet both current and forecasted customer requirements. The Company's 35,000 dth/day of NED capacity represents the sum of the Company's existing Dracut capacity on Tennessee of 15,000 MMBtu/day plus an incremental volume of 20,000 MMBtu/day. The Company's existing Dracut contract will terminate as of the in-service date of the NED Project, thereby replacing an illiquid receipt point at Dracut, Massachusetts with a more liquid receipt point at Wright, New York.

IV.C.4.b Pending LNG Supply Agreements

- *Gaz Metro LNG, L.P. (Gaz Metro)*
  The Company has entered into a three-year Agreement for purchase of up to 63,500 dts during the 2016 refill season and 190,500 dts during the 2017 and 2018 refill seasons. The Gaz Metro Agreement requires construction of additional facilities at Gaz Metro's location in Montreal, Quebec. The volumes purchased from Gaz Metro will be purchased from Gaz Metro's current facilities until the commercial operation date of the expansion facilities (2016). After the commercial operation date, all capacity will be purchased from the Gaz Metro expansion facilities (the "LSR Plant"). The LNG with be trucked from Montreal to the Company's LNG facilities in Rhode Island.

- *GDF Suez Gas NA LLC (GDF Suez)*
  The Company has entered into a nine-year Agreement for purchase of up to 4,000 dts/day and up to 508,000 dts/refill season. The LNG with be trucked from GDF Suez's terminal in Everett, MA to the Company's LNG facilities in Rhode Island.

IV.C.4.c Pending LNG Liquefaction Service Agreements

- *National Grid LNG (NGLNG)*
  The Company has entered into a Precedent Agreement for up to 2,616 dt/day and 507,504 dt/refill season for a term of 20 years commencing upon completion of facilities to expand NGLNG's currently existing storage facilities located in Providence, Rhode Island; the liquefaction facilities have an expected in-service date of April 1, 2019. The NGLNG facilities will access Algonquin, so the Company will utilize its existing Algonquin capacity to transport volumes to the proposed liquefaction facility. Currently, the Company has a storage agreement with NGLNG for LNG storage at the Providence site pursuant to an agreement dated November 30, 1998. This agreement is not expected to change. The LNG will fill the Company's storage capacity in the NGLNG tank, and volumes needed to fill the Cumberland and Exeter facilities will be trucked.

- *Northeast Energy Center, LLC (Northeast Energy)*
  The Company has entered into a Precedent Agreement for up to 1,780 dt/day and 380,920 dt/refill season for a term of 15 years commencing upon completion of necessary facilities. The Northeast Energy project is located in central Massachusetts and has an expected in service date of April 1, 2019. The Northeast Energy Project will connect to the Tennessee pipeline. The Company will utilize its existing Tennessee capacity to transport volumes from the zone 4 producing region to the proposed liquefaction facility located in zone 6. The LNG with be trucked from the facility to the Company's LNG facilities in Rhode Island.

IV.C.5. Natural Gas Portfolio Management Plan

In Docket No. 4038, the Commission approved the Natural Gas Portfolio Management Plan (NGPMP), which implemented changes to the management of the Company's gas portfolio. These changes were designed to provide various financial, regulatory, and risk management benefits over previous asset management arrangements. The Company changed the management of the gas portfolio from an external third-party asset-management agreement to a portfolio managed primarily by the Company. The Company uses its transportation contracts, underground storage contracts, peaking supplies, and supply contracts first to purchase gas supplies to economically and reliably serve sales customers and then to make additional purchases and sales that generate revenue by extracting value from any assets that are not required to serve customers on any day. The mix of supply, transportation, and storage contracts creates flexibility and opportunities for optimization to create value for the Company's customers. This potential optimization value is subject to market variables: the fluctuation of gas pricing, the value of temporarily unused assets, the existence of excess transportation and storage capacity, and the opportunities to optimize delivered supplies as storage fill opportunities arise. These activities were previously executed by external third-party asset managers.

IV.C.6. Future Portfolio Decisions

During the forecast period, the Company will be faced with critical decisions regarding the expiration of a significant number of its transportation, underground storage and off-system peaking contracts in its portfolio. As of March 1, 2016, the following contracts require a decision within the ten-year term of this plan:

- Forty-seven (47) of the Company's fifty (50) transportation contracts; and
- Ten (10) of the Company's eleven (11) underground storage contracts

During the forecast period, the Company will employ a two-step analysis to reach its conclusions on contract renewals, as well as the addition of new resources. First, depending on the type of need, the Company will canvas the marketplace to determine the availability of a replacement or new resource. And, where appropriate, the Company will solicit competitive bids to determine the lowest-cost available resource.

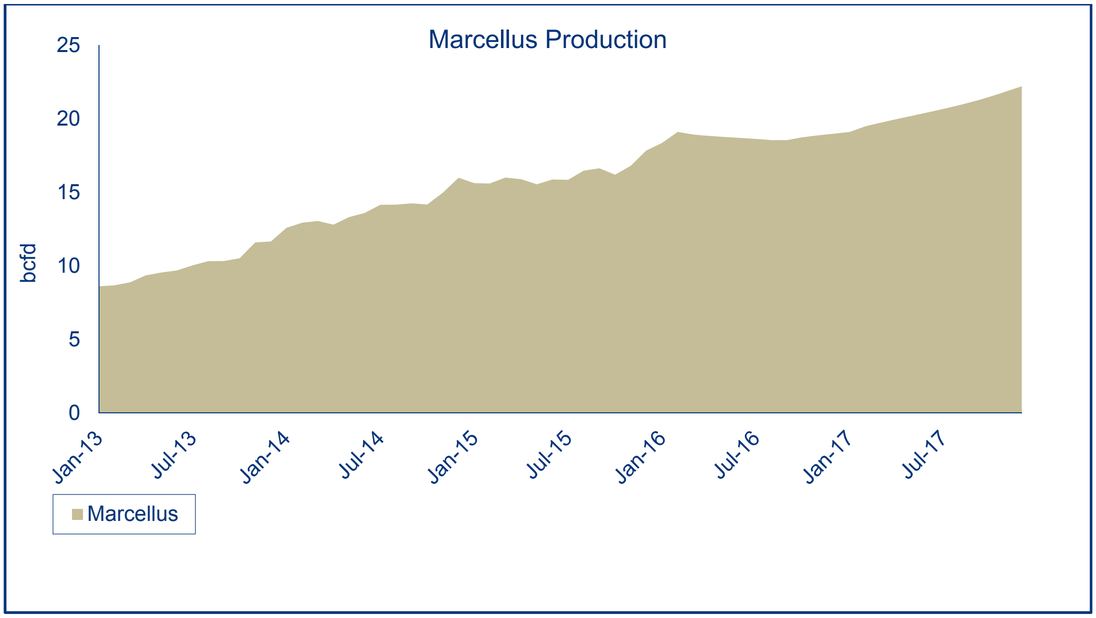
Then, the Company will evaluate non-price factors associated with the available replacement or new resource option. The Company will consider the flexibility, diversity, reliability and contract term to determine the least-cost, most reliable option to meet the Company's resource need.

Absent the development of new incremental capacity projects or upgrades to on-system facilities that present cost-effective alternatives to the existing resource portfolio, the Company expects to renew its existing contracts for an extended time period to maintain flexibility, diversity and reliability consistent with least-cost principles. As discussed above, pipeline rates for legacy[5] capacity are advantaged by the significant depreciation of plant and rate base associated with legacy capacity, as well as by revenue requirement recovery at average cost-based rates. Moreover, the respective interstate pipelines flow natural gas at higher load factors (with greater billing determinants), which helps to maintain the low rates associated with these pipelines.

IV.C.7. Future Supply and Capacity Projects

During the forecast period, the Company must continue its monitoring of the Northeast market, in particular, the effects of domestic and imported supplies on the overall supply dynamic. To date, there have been a significant number of projects which have gone into service bringing domestic shale gas from the Marcellus region to market. Construction of gathering systems by producers continues, with the additional production creating more liquidity in the shale basin. In fact, in WoodMackenzie's February 2016 North America Gas Markets Short-Term Outlook, Marcellus production is forecasted to reach 22.21 bcf/day by December 2017 (see chart below).

[5] Legacy capacity is defined herein as firm interstate pipeline transportation and storage service provided to the Company and other LDCs under FERC-approved rate schedules that were in effect upon or soon after the unbundling of the U.S. interstate pipeline system resulting from FERC Order No. 636.



WoodMacKenzie Feb/16

The Company's Rhode Island portfolio continues to be situated to take advantage of opportunities with a good balance of economically-priced market-area transportation on existing short-haul capacity and competitively priced supply from the Gulf of Mexico (GOM) enhanced by shale plays such as the Eagle Ford and other midcontinent shales on existing long-haul capacity. The Company will continue to monitor the relationship in price to see if these trends continue. As such, when upstream contracts are due to expire; the Company will have more data to make the appropriate decision. Therefore, as the new supply side options develop, the Company will continue to evaluate the portfolio for opportunities to reduce costs. The portfolio planning process must also consider the ability to access gas supply in a way that enhances the stability of prices to customers. Some supply sourcing options have proven to be vulnerable to severe price spikes during peak demand periods over the last few years. The Company has taken steps to mitigate this exposure via its commitments to Algonquin's AIM Project, Millennium's Expansion Project and Tennessee's NED Project.

Although price factors are the primary driver for contract portfolio decisions, the non-price factor of supply reliability cannot be understated. A diverse portfolio with supply sourcing options helps to mitigate both price and reliability issues. As discussed, the Company found itself needing to re-evaluate the long-term reliability of its gas supply portfolio, with particular focus on LNG, and the need for a long-term solution. To that end, the Company has taken steps to mitigate this exposure via its commitments to long-term LNG supply and liquefaction services.

IV.D. Adequacy of the Resource Portfolio

IV.D.1. The Design Year Forecast

For the design days as shown in Chart IV-C-1, the Company's forecast demonstrates that it relies on its pipeline and underground storage transportation contracts to meet the bulk of its customer requirements. LNG serves as the swing supply. The forecast shows that the Company would use between 107 and 138 BBtu of its 145 BBtu/day vaporization capacity to meet supply requirements. The vaporization capacity allows the Company flexibility in dispatching additional LNG if price-advantageous as well as providing reliability and diversity to its supply portfolio. The forecast also shows an unserved need. This need represents additional resources that are needed over and above the available assets in the portfolio that must be acquired by the Company. This need is filled through the procurement of a citygate-delivered supply. This purchasing strategy minimizes the cost of the resource portfolio because the Company is able to avoid annual demand charges for capacity. However, the level at which the Company can depend on such resources varies due to a number of factors, including but not limited to: current market conditions, capacity availability, and supply availability. As such, the Company will fill the need through the addition of long-term capacity contracts or other long-term arrangements.

Over the base case design heating season as shown in Chart IV-C-1, the Company's forecasted customer requirements over and above its transportation and storage deliverability to the Company's citygate ranges between 793 and 1,511 BBtu/year which needs to be met by a combination of LNG resources and citygate peaking supplies, The Company's design winter weather is only one of many possible weather scenarios which could occur and therefore the flexibility in its LNG resources has great value. Having an asset like LNG under the Company's control, which is readily dispatchable and located in the Company's service territory, provides reliability and diversity to the entire Company resource portfolio.

IV.D.2. Cold Snap Analysis

In addition to the design-year, design-day, and normal-year planning standards, the Company also evaluates the capability of the resource portfolio to meet sendout requirements during a protracted period of very cold weather, which is referred to as a "cold snap." The cold snap evaluation is performed by modeling daily sendout and observing the predicted resource usage over a specified set of HDD. For its current filing, the Company has used a 14-day cold snap occurring in the coldest 14-day period of the Company's normal year (15 Jan - 28 Jan; 516 HDD) to test the adequacy of inventories and refill requirements.

From the evaluation of January weather data from the forty years 1976 - 2015, the mean total HDD for the period 15 Jan - 28 Jan is 602 HDD with a standard deviation of 71.1HDD. Selecting a test value of the mean plus 2.06 times the standard deviation for a once-in-50 year occurrence yields a 14-day cold snap total of 748 HDD, just 9 HDD greater than the Jan 2-15, 1981 figure of 739 HDD. For its current cold snap HDD pattern, the Company took the actual HDD data for Jan 2-15, 1981, adding 9 HDD to the actual data to arrive at its cold snap weather pattern. The Company then assumed normal weather up until Jan 15, followed by the cold snap period data, then followed by normal weather after the cold snap interval. For the normal year, the annual HDD are 5,611. The annual HDD for the cold snap scenario are 5,843 HDD (5611 - 516 + 748).

For the cold snap heating season as shown in Chart IV-C-1, the Company's forecasted customer requirements over and above its transportation and storage deliverability to the Company's cityage ranges between 1,067 and 1,658 BBtu/year, which needs to be met by a combination of LNG resources and citygate peaking supplies.

Section V
Charts & Tables

V. Charts and Tables

Econometric and Demographic Input Variables

Variable	Description	Units
FE23	Employment: Construction	Thousands, Seasonally Adjusted
FEMF	Employment: Manufacturing	Thousands, Seasonally Adjusted
FET	Employment: Total	Thousands, Seasonally Adjusted
FETL	Employment: Trade, Transportation and Utilitie	Thousands, Seasonally Adjusted
FGDP	Gross State Product: Total	Billions 2009 $, Seasonally Adjusted
FHHOLD	Households: Total	Thousands
FPOP	Population: Total	Thousands
FRTFS	Retail Sales: Total	Billions $, Seasonally Adjusted
FYPCPI	Income: Per Capita	2009 $, Seasonally Adjusted Annual Rate
FYP	Income: Total Personal	Millions 2009 $, Seasonally Adjusted Annual Rate
CPI	CPI: All Items	Index, 1982-84 = 100, Seasonally Adjusted

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FE23.RI	FE23_S3.RI	FE23_S8.RI	FEMF.RI	FEMF_S3.RI
Concept:	FE23	FE23_S3	FE23_S8	FEMF	FEMF_S3
Description:	Employment: Construction, (Ths., SA)	Moderate Recession Scenario (November 2015): Employment: Construction, (Ths., SA)	Low Oil Price Scenario (November 2015): Employment: Construction, (Ths., SA)	Employment: Total Manufacturing, (Ths., SA)	Moderate Recession Scenario (November 2015): Employment: Total Manufacturing, (Ths., SA)
Source:	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics
Databank:	STFOR.db	STFOR_S3.db	stfor_s8.db	STFOR.db	STFOR_S3.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None	None	None
Geography:	Rhode Island	Rhode Island	Rhode Island	Rhode Island	Rhode Island
GeoCode:	RI	RI	RI	RI	RI
Begin Date:	12/31/1970	12/31/1970	12/31/1970	12/31/1970	12/31/1970
Last Updated:	11/16/2015	11/23/2015	11/23/2015	11/16/2015	11/23/2015
Historical End Date:	12/31/14	12/31/14	12/31/14	12/31/14	12/31/14
1995	13.40	13.40	13.40	80.40	80.40
1996	14.01	14.01	14.01	77.41	77.41
1997	14.64	14.64	14.64	76.23	76.23
1998	15.99	15.99	15.99	74.79	74.79
1999	17.80	17.80	17.80	72.12	72.12
2000	18.16	18.16	18.16	71.24	71.24
2001	19.00	19.00	19.00	67.80	67.80
2002	19.42	19.42	19.42	62.31	62.31
2003	20.76	20.76	20.76	58.72	58.72
2004	20.97	20.97	20.97	56.93	56.93
2005	21.77	21.77	21.77	54.95	54.95
2006	22.83	22.83	22.83	52.75	52.75
2007	22.15	22.15	22.15	50.75	50.75
2008	20.43	20.42	20.42	47.94	47.94
2009	17.19	17.19	17.19	41.74	41.74
2010	15.97	15.97	15.97	40.33	40.33
2011	15.72	15.72	15.72	40.11	40.11
2012	16.08	16.08	16.08	39.64	39.64
2013	16.14	16.14	16.14	40.03	40.03
2014	16.43	16.43	16.43	40.93	40.93
2015	15.49	15.49	15.49	41.82	41.82
2016	16.16	15.15	16.26	41.75	40.57
2017	17.58	15.47	18.15	41.62	39.23
2018	18.38	16.43	19.19	41.54	39.32
2019	18.71	17.69	19.36	41.28	39.73
2020	18.84	18.80	19.09	40.68	40.08
2021	18.96	19.33	18.85	39.99	39.91
2022	19.05	19.33	18.77	39.39	39.30
2023	19.11	19.39	18.88	38.84	38.76
2024	19.13	19.43	18.99	38.29	38.22
2025	19.11	19.41	19.02	37.77	37.72
2026	19.08	19.37	19.07	37.28	37.23
2027	19.09	19.37	19.20	36.83	36.79
2028	19.15	19.41	19.30	36.41	36.37
2029	19.21	19.45	19.32	36.03	35.99
2030	19.32	19.53	19.34	35.67	35.63
2031	19.45	19.62	19.40	35.33	35.29
2032	19.60	19.75	19.51	34.98	34.94
2033	19.82	19.92	19.69	34.65	34.60
2034	20.08	20.14	19.96	34.30	34.26
2035	20.37	20.39	20.27	33.96	33.92

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FEMF_S8.RI	FET.RI	FET_S3.RI	FET_S8.RI	FETL.RI
Concept:	FEMF_S8	FET	FET_S3	FET_S8	FETL
Description:	Low Oil Price Scenario (November 2015): Employment: Total Manufacturing, (Ths., SA)	Employment: Total Nonagricultural, (Ths., SA)	Moderate Recession Scenario (November 2015): Employment: Total Nonagricultural, (Ths., SA)	Low Oil Price Scenario (November 2015): Employment: Total Nonagricultural, (Ths., SA)	Employment: Trade, Transportation & Utilities, (Ths., SA)
Source:	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics
Databank:	stfor_s8.db	STFOR.db	STFOR_S3.db	stfor_s8.db	STFOR.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None	None	None
Geography:	Rhode Island	Rhode Island	Rhode Island	Rhode Island	Rhode Island
GeoCode:	RI	RI	RI	RI	RI
Begin Date:	12/31/1970	12/31/1970	12/31/1970	12/31/1970	12/31/1970
Last Updated:	11/23/2015	11/16/2015	11/23/2015	11/23/2015	11/16/2015
Historical End Date:	12/31/14	12/31/14	12/31/14	12/31/14	12/31/14
1995	80.40	439.13	439.13	439.13	74.43
1996	77.41	440.77	440.77	440.77	72.67
1997	76.23	450.06	450.06	450.06	72.89
1998	74.79	457.95	457.95	457.95	74.70
1999	72.12	465.50	465.50	465.50	75.66
2000	71.24	476.91	476.91	476.91	79.61
2001	67.80	478.51	478.51	478.51	79.28
2002	62.31	479.43	479.43	479.43	80.45
2003	58.72	484.27	484.28	484.28	80.77
2004	56.93	488.48	488.48	488.48	80.27
2005	54.95	491.13	491.12	491.12	80.12
2006	52.75	492.98	492.98	492.98	79.73
2007	50.75	492.02	492.02	492.02	79.76
2008	47.94	481.06	481.06	481.06	77.40
2009	41.74	459.35	459.35	459.35	73.27
2010	40.33	458.00	458.00	458.00	72.72
2011	40.11	460.54	460.54	460.54	73.90
2012	39.64	465.57	465.57	465.57	74.61
2013	40.03	471.63	471.63	471.63	74.09
2014	40.93	477.73	477.73	477.73	74.99
2015	41.82	483.14	483.14	483.14	75.44
2016	41.61	489.77	477.92	490.66	75.83
2017	41.85	496.89	473.29	502.48	76.16
2018	42.06	503.80	481.58	512.31	76.78
2019	41.95	508.51	493.16	517.26	77.19
2020	41.18	510.19	504.57	515.93	77.15
2021	40.13	511.59	511.20	513.04	77.02
2022	39.29	513.84	513.24	512.60	77.03
2023	38.71	516.33	515.82	514.89	77.12
2024	38.20	518.47	518.17	517.44	77.20
2025	37.68	520.68	520.49	519.72	77.30
2026	37.23	522.94	522.77	522.37	77.41
2027	36.84	525.27	525.08	525.43	77.48
2028	36.46	527.76	527.50	528.24	77.57
2029	36.05	530.51	530.25	530.61	77.69
2030	35.63	533.43	533.12	532.85	77.73
2031	35.25	536.42	536.01	535.30	77.67
2032	34.88	539.39	538.87	537.91	77.61
2033	34.52	542.50	541.87	540.72	77.58
2034	34.18	545.71	545.00	543.85	77.60
2035	33.84	549.08	548.29	547.33	77.63

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FETL_S3.RI	FETL_S8.RI	FGDP$Q.RI	FGDP$Q_S3.RI	FGDP$Q_S8.RI
Concept:	FETL_S3	FETL_S8	FGDP$Q	FGDP$Q_S3	FGDP$Q_S8
Description:	Moderate Recession Scenario (November 2015): Employment: Trade, Transportation & Utilities, (Ths., SA)	Low Oil Price Scenario (November 2015): Employment: Trade, Transportation & Utilities, (Ths., SA)	Gross State Product: Total, (Bil. Chained 2009 $, SAAR)	Moderate Recession Scenario (November 2015): Gross State Product: Total, (Bil. Chained 2009 $, SAAR)	Low Oil Price Scenario (November 2015): Gross State Product: Total, (Bil. Chained 2009 $, SAAR)
Source:	BLS; BEA; BOC: CBP; Moody's Analytics	BLS; BEA; BOC: CBP; Moody's Analytics	BEA; Moody's Analytics	BEA; Moody's Analytics	BEA; Moody's Analytics
Databank:	STFOR_S3.db	stfor_s8.db	STFOR.db	STFOR_S3.db	stfor_s8.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None	None	None
Geography:	Rhode Island	Rhode Island	Rhode Island	Rhode Island	Rhode Island
GeoCode:	RI	RI	RI	RI	RI
Begin Date:	12/31/1970	12/31/1970	12/31/1977	12/31/1977	12/31/1977
Last Updated:	11/23/2015	11/23/2015	11/16/2015	11/23/2015	11/23/2015
Historical End Date:	12/31/14	12/31/14	12/31/14	12/31/14	12/31/14
1995	74.43	74.43	35.78	35.78	35.78
1996	72.67	72.67	36.40	36.40	36.40
1997	72.89	72.89	38.70	38.70	38.70
1998	74.70	74.70	40.07	40.07	40.07
1999	75.66	75.66	41.46	41.46	41.46
2000	79.61	79.61	43.27	43.27	43.27
2001	79.28	79.28	44.21	44.21	44.21
2002	80.45	80.45	45.75	45.75	45.75
2003	80.77	80.77	47.67	47.67	47.67
2004	80.27	80.27	49.53	49.53	49.53
2005	80.12	80.12	49.92	49.92	49.92
2006	79.73	79.73	50.93	50.93	50.93
2007	79.76	79.76	49.76	49.76	49.76
2008	77.40	77.40	48.38	48.38	48.38
2009	73.27	73.27	47.85	47.85	47.85
2010	72.72	72.72	48.79	48.79	48.79
2011	73.90	73.90	48.65	48.65	48.65
2012	74.61	74.61	49.02	49.02	49.02
2013	74.09	74.09	49.94	49.94	49.94
2014	74.99	74.99	50.54	50.54	50.54
2015	75.44	75.44	51.08	51.08	51.08
2016	73.83	76.07	52.45	50.64	52.64
2017	72.35	77.23	53.65	50.57	54.40
2018	73.23	78.34	54.60	51.93	55.64
2019	74.66	78.78	55.38	53.97	56.41
2020	76.15	78.22	56.02	55.68	56.65
2021	76.87	77.36	56.88	56.76	56.97
2022	76.84	76.91	57.83	57.72	57.63
2023	76.97	76.96	58.78	58.67	58.61
2024	77.10	77.09	59.69	59.62	59.56
2025	77.22	77.18	60.59	60.54	60.47
2026	77.34	77.34	61.51	61.45	61.46
2027	77.43	77.52	62.49	62.40	62.54
2028	77.50	77.64	63.50	63.47	63.59
2029	77.63	77.71	64.54	64.49	64.56
2030	77.68	77.65	65.61	65.52	65.53
2031	77.63	77.52	66.69	66.55	66.53
2032	77.56	77.41	67.82	67.65	67.61
2033	77.54	77.35	68.99	68.78	68.74
2034	77.56	77.35	70.17	69.90	69.91
2035	77.60	77.40	71.37	71.06	71.12

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FHHOLDQ.RI	FHHOLDQ_S3.RI	FHHOLDQ_S8.RI	FPOPQ.RI	FPOPQ_S3.RI
Concept:	FHHOLDQ	FHHOLDQ_S3	FHHOLDQ_S8	FPOPQ	FPOPQ_S3
Description:	Households: Total, (Ths.)	Moderate Recession Scenario (November 2015): Households: Total, (Ths.)	Low Oil Price Scenario (November 2015): Households: Total, (Ths.)	Population: Total, (Ths.)	Moderate Recession Scenario (November 2015): Population: Total, (Ths.)
Source:	BOC; Moody's Analytics	BOC; Moody's Analytics	BOC; Moody's Analytics	BOC; Moody's Analytics	BOC; Moody's Analytics
Databank:	STFOR.db	STFOR_S3.db	stfor_s8.db	STFOR.db	STFOR_S3.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None	None	None
Geography:	Rhode Island	Rhode Island	Rhode Island	Rhode Island	Rhode Island
GeoCode:	RI	RI	RI	RI	RI
Begin Date:	12/31/1960	12/31/1960	12/31/1960	12/31/1900	12/31/1900
Last Updated:	11/16/2015	11/23/2015	11/23/2015	11/16/2015	11/23/2015
Historical End Date:	12/31/09	12/31/09	12/31/09	12/31/13	12/31/13
1995	390.85	390.85	390.85	1018.70	1018.70
1996	393.86	393.86	393.86	1023.09	1023.09
1997	397.08	397.08	397.08	1027.91	1027.91
1998	401.28	401.28	401.28	1035.41	1035.41
1999	406.85	406.85	406.85	1045.65	1045.65
2000	410.92	410.92	410.92	1053.70	1053.70
2001	414.29	414.29	414.29	1061.64	1061.64
2002	417.56	417.56	417.56	1068.95	1068.95
2003	419.80	419.80	419.80	1073.87	1073.87
2004	419.40	419.40	419.40	1071.94	1071.94
2005	417.00	417.00	417.00	1065.35	1065.35
2006	415.40	415.40	415.40	1060.00	1060.00
2007	414.57	414.57	414.57	1055.82	1055.82
2008	414.51	414.51	414.51	1054.27	1054.27
2009	414.43	414.43	414.43	1053.37	1053.37
2010	414.85	414.85	414.85	1052.47	1052.47
2011	416.25	416.25	416.25	1052.18	1052.18
2012	417.31	417.31	417.31	1052.99	1052.99
2013	416.79	416.79	416.79	1054.00	1054.00
2014	416.90	416.90	416.90	1056.86	1056.86
2015	419.28	419.28	419.28	1060.45	1060.45
2016	422.19	422.64	422.36	1063.09	1063.09
2017	425.54	425.94	426.38	1065.77	1065.77
2018	427.21	427.55	428.70	1068.52	1068.52
2019	428.96	429.18	430.77	1071.31	1071.31
2020	430.19	430.25	431.57	1074.09	1074.09
2021	431.51	431.52	432.19	1076.78	1076.78
2022	433.01	433.02	433.28	1079.39	1079.39
2023	434.57	434.57	434.79	1081.88	1081.88
2024	435.96	435.96	436.23	1084.24	1084.24
2025	437.42	437.43	437.66	1086.47	1086.47
2026	438.71	438.71	438.94	1088.62	1088.62
2027	440.28	440.29	440.54	1090.69	1090.69
2028	441.84	441.85	442.10	1092.68	1092.68
2029	443.45	443.46	443.64	1094.52	1094.52
2030	444.91	444.92	445.00	1096.27	1096.27
2031	446.34	446.35	446.34	1097.96	1097.96
2032	447.81	447.82	447.75	1099.66	1099.66
2033	449.08	449.08	448.96	1101.32	1101.31
2034	450.24	450.24	450.10	1102.95	1102.95
2035	451.34	451.35	451.20	1104.56	1104.56

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FPOPQ_S8.RI	FRTFSQ.RI	FRTFSQ_S3.RI	FRTFSQ_S8.RI	FYPCPI$Q.RI
Concept:	FPOPQ_S8	FRTFSQ	FRTFSQ_S3	FRTFSQ_S8	FYPCPI$Q
Description:	Low Oil Price Scenario (November 2015): Population: Total, (Ths.)	Retail Sales: Total, (Bil. $, SAAR)	Moderate Recession Scenario (November 2015): Retail Sales: Total, (Bil. $, SAAR)	Low Oil Price Scenario (November 2015): Retail Sales: Total, (Bil. $, SAAR)	Per Capita Income, (C 09$, SAAR)
Source:	BOC; Moody's Analytics	BOC; Moody's Analytics	BOC; Moody's Analytics	BOC; Moody's Analytics	BEA; BOC; Moody's Analytics
Databank:	stfor_s8.db	STFOR.db	STFOR_S3.db	stfor_s8.db	STFOR.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None	None	None
Geography:	Rhode Island	Rhode Island	Rhode Island	Rhode Island	Rhode Island
GeoCode:	RI	RI	RI	RI	RI
Begin Date:	12/31/1900	12/31/1970	12/31/1970	12/31/1970	12/31/1948
Last Updated:	11/23/2015	11/16/2015	11/23/2015	11/23/2015	11/16/2015
Historical End Date:	12/31/13	12/31/14	12/31/14	12/31/14	12/31/13
1995	1018.70	8.21	8.21	8.21	31033.26
1996	1023.09	8.21	8.21	8.21	31362.29
1997	1027.91	8.59	8.59	8.59	32498.98
1998	1035.41	9.08	9.08	9.08	34266.61
1999	1045.65	9.78	9.78	9.78	34923.67
2000	1053.70	10.77	10.77	10.77	36315.02
2001	1061.64	11.29	11.29	11.29	37218.94
2002	1068.95	12.07	12.07	12.07	38053.03
2003	1073.87	12.79	12.79	12.79	38954.77
2004	1071.94	13.29	13.29	13.29	39676.30
2005	1065.35	13.78	13.78	13.78	39679.08
2006	1060.00	14.19	14.19	14.19	40967.82
2007	1055.82	14.34	14.34	14.34	41918.59
2008	1054.27	13.70	13.70	13.70	41871.42
2009	1053.37	12.77	12.77	12.77	41082.84
2010	1052.47	13.28	13.28	13.28	42047.74
2011	1052.18	14.01	14.01	14.01	42524.16
2012	1052.99	14.39	14.39	14.39	43421.39
2013	1054.00	14.62	14.62	14.62	42889.68
2014	1056.86	15.16	15.16	15.16	44303.84
2015	1060.45	15.43	15.43	15.43	45592.60
2016	1063.09	16.41	15.60	16.34	46632.04
2017	1065.77	17.41	16.06	17.50	47420.60
2018	1068.52	18.28	17.14	18.35	48072.56
2019	1071.31	19.01	18.37	19.01	48429.06
2020	1074.09	19.61	19.39	19.53	48659.52
2021	1076.78	20.23	20.17	20.03	49070.73
2022	1079.39	20.88	20.89	20.63	49566.65
2023	1081.88	21.53	21.57	21.37	50117.06
2024	1084.24	22.15	22.22	22.09	50707.25
2025	1086.47	22.79	22.88	22.81	51336.10
2026	1088.62	23.44	23.56	23.55	51993.49
2027	1090.69	24.12	24.26	24.31	52721.49
2028	1092.68	24.88	25.04	25.11	53483.76
2029	1094.52	25.67	25.87	25.89	54291.99
2030	1096.27	26.49	26.73	26.68	55140.66
2031	1097.96	27.37	27.64	27.54	56015.41
2032	1099.66	28.27	28.59	28.44	56914.69
2033	1101.31	29.23	29.59	29.38	57808.23
2034	1102.95	30.28	30.70	30.45	58642.63
2035	1104.56	31.44	31.92	31.64	59425.96

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FYPCPI$Q_S3.RI	FYPCPI$Q_S8.RI	FYP$Q.RI	FYP$Q_S3.RI	FYP$Q_S8.RI
Concept:	FYPCPI$Q_S3	FYPCPI$Q_S8	FYP$Q	FYP$Q_S3	FYP$Q_S8
Description:	Moderate Recession Scenario (November 2015): Per Capita Income, (C 09$, SAAR)	Low Oil Price Scenario (November 2015): Per Capita Income, (C 09$, SAAR)	Real Personal Income, (Mil. 09$, SAAR)	Moderate Recession Scenario (November 2015): Real Personal Income, (Mil. 09$, SAAR)	Low Oil Price Scenario (November 2015): Real Personal Income, (Mil. 09$, SAAR)
Source:	BEA; BOC; Moody's Analytics	BEA; BOC; Moody's Analytics	BEA; Moody's Analytics	BEA; Moody's Analytics	BEA; Moody's Analytics
Databank:	STFOR_S3.db	stfor_s8.db	STFOR.db	STFOR_S3.db	stfor_s8.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None	None	None
Geography:	Rhode Island	Rhode Island	Rhode Island	Rhode Island	Rhode Island
GeoCode:	RI	RI	RI	RI	RI
Begin Date:	12/31/1948	12/31/1948	12/31/1948	12/31/1948	12/31/1948
Last Updated:	11/23/2015	11/23/2015	11/16/2015	11/23/2015	11/23/2015
Historical End Date:	12/31/13	12/31/13	12/31/14	12/31/14	12/31/14
1995	31033.26	31033.26	31576.17	31576.17	31576.17
1996	31362.29	31362.29	32034.90	32034.90	32034.90
1997	32498.98	32498.98	33344.75	33344.75	33344.75
1998	34266.61	34266.61	35373.65	35373.65	35373.65
1999	34923.67	34923.67	36382.05	36382.05	36382.05
2000	36315.02	36315.02	38169.17	38169.17	38169.17
2001	37218.94	37218.94	39390.78	39390.78	39390.78
2002	38053.03	38053.03	40588.57	40588.57	40588.57
2003	38954.77	38954.77	41760.12	41760.12	41760.12
2004	39676.30	39676.30	42599.86	42599.86	42599.86
2005	39679.08	39679.08	42354.45	42354.45	42354.45
2006	40967.82	40967.82	43516.67	43516.67	43516.67
2007	41918.59	41918.59	44309.16	44309.16	44309.16
2008	41871.42	41871.42	44166.91	44166.91	44166.91
2009	41082.84	41082.84	43285.11	43285.11	43285.11
2010	42047.74	42047.74	44272.00	44272.00	44272.00
2011	42524.16	42524.16	44739.90	44739.90	44739.90
2012	43421.39	43421.39	45710.32	45710.32	45710.32
2013	42889.68	42889.68	45185.68	45185.68	45185.68
2014	44303.84	44303.84	46767.69	46767.69	46767.69
2015	45592.60	45592.60	48290.74	48290.74	48290.74
2016	44897.10	47020.27	49528.71	47685.49	49941.18
2017	44442.03	48352.73	50491.50	47319.95	51484.09
2018	45546.29	49478.24	51316.77	48620.33	52817.39
2019	47677.71	49968.37	51831.71	51028.02	53479.12
2020	49202.00	49735.82	52214.27	52796.51	53369.06
2021	49656.89	49607.42	52789.09	53419.61	53366.35
2022	49940.94	49850.31	53453.78	53857.39	53759.67
2023	50382.32	50392.59	54174.35	54461.07	54472.20
2024	50944.51	50968.17	54934.50	55191.54	55217.17
2025	51532.33	51533.23	55732.44	55945.48	55946.45
2026	52125.34	52182.85	56559.46	56702.88	56765.45
2027	52785.18	52942.07	57462.40	57531.81	57702.81
2028	53534.51	53688.49	58401.35	58456.76	58624.88
2029	54276.08	54427.24	59386.70	59369.29	59534.63
2030	55039.78	55195.09	60413.24	60302.70	60472.86
2031	55820.50	56008.86	61467.50	61253.60	61460.30
2032	56624.34	56864.82	62550.62	62231.52	62495.81
2033	57411.57	57723.27	63629.38	63192.76	63535.86
2034	58139.82	58544.02	64644.33	64090.05	64535.63
2035	58821.16	59331.67	65604.10	64936.42	65500.01

Narragansett Electric Company
d/b/a National Grid
Input Economic Data

Mnemonic:	FCPIU.US	FCPIU_S3.US	FCPIU_S8.US
Concept:	FCPIU	FCPIU_S3	FCPIU_S8
Description:	CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	Moderate Recession Scenario (December 2015): CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	Low Oil Price Scenario (December 2015): CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)
	U.S. Bureau of Labor Statistics (BLS); Moody's Analytics (ECCA)	U.S. Bureau of Labor Statistics (BLS); Moody's Analytics (ECCA)	U.S. Bureau of Labor Statistics (BLS); Moody's Analytics (ECCA)
Source:	Forecast	Forecast	Forecast
Databank:	USFOR.db	usfor_s3.db	USFOR_S8.db
Native Frequency:	QUARTERLY	QUARTERLY	QUARTERLY
Transformation:	None	None	None
Geography:	United States	United States	United States
GeoCode:	US	US	US
Begin Date:	12/31/1947	12/31/1947	12/31/1947
Last Updated:	12/07/2015	12/09/2015	12/09/2015
Historical End Date:	12/31/14	12/31/14	12/31/14
1995	152.38	152.38	152.38
1996	156.86	156.86	156.86
1997	160.53	160.53	160.53
1998	163.01	163.01	163.01
1999	166.58	166.58	166.58
2000	172.19	172.19	172.19
2001	177.04	177.04	177.04
2002	179.87	179.87	179.87
2003	184.00	184.00	184.00
2004	188.91	188.91	188.91
2005	195.27	195.27	195.27
2006	201.56	201.56	201.56
2007	207.34	207.34	207.34
2008	215.25	215.25	215.25
2009	214.56	214.56	214.56
2010	218.08	218.08	218.08
2011	224.93	224.93	224.93
2012	229.60	229.60	229.60
2013	232.96	232.96	232.96
2014	236.71	236.71	236.71
2015	237.07	237.07	237.07
2016	241.63	237.96	238.61
2017	248.31	241.29	243.68
2018	255.69	248.48	250.16
2019	262.67	256.30	257.34
2020	269.00	264.64	265.47
2021	275.20	272.85	273.33
2022	281.46	280.42	280.57
2023	287.82	287.25	287.60
2024	294.18	293.94	294.66
2025	300.52	300.64	301.58
2026	306.99	307.49	308.20
2027	313.68	314.61	314.97
2028	320.60	322.01	321.99
2029	327.64	329.58	329.14
2030	334.75	337.29	336.35
2031	341.94	345.13	343.60
2032	349.26	353.16	350.96
2033	356.73	361.41	358.46
2034	364.32	369.84	366.07
2035	372.04	378.46	373.81

Narragansett Electric Company d/b/a NATIONAL GRID
Forecasted Retail Gas Deliveries by Rate Code in Dth (2015/16 - 2024/25)

Rate Code	Rate Code Name	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
400	Residential Heating	17,189,176	17,376,477	17,643,507	17,881,605	18,086,102	18,272,681	18,414,455	18,632,566	18,845,514	19,084,302
401	Residential Non-Heating	675,513	662,385	649,379	640,712	635,230	628,001	618,546	608,332	597,680	590,334
402	Residential Low Income Heating	1,734,190	1,660,065	1,597,205	1,552,222	1,515,793	1,465,455	1,402,551	1,343,995	1,284,974	1,251,240
403	Residential Low Income Non-Heating	26,020	25,033	24,384	23,791	22,645	20,939	19,295	17,872	16,484	15,671
404	C&I Small	2,337,301	2,358,455	2,388,709	2,411,110	2,434,282	2,453,690	2,470,335	2,501,428	2,529,261	2,566,636
405	C&I Medium	3,200,041	3,256,076	3,315,085	3,385,547	3,433,610	3,461,721	3,479,604	3,508,946	3,531,720	3,560,016
406	FT2 Medium	1,715,966	1,789,209	1,868,370	1,939,135	2,008,937	2,080,813	2,153,770	2,233,480	2,315,952	2,371,839
407	FT1 Medium	678,802	675,150	672,583	669,161	662,177	650,435	641,756	633,786	627,410	623,167
408	TSS Medium	205,297	270,744	342,363	402,390	425,918	433,995	452,077	477,314	499,369	515,191
409	C&I Low Load - Large	609,091	625,838	644,220	663,834	675,366	681,787	687,074	695,283	702,345	710,153
410	FT2 Large Low	1,033,286	1,042,254	1,100,017	1,147,912	1,148,552	1,121,176	1,107,492	1,112,531	1,117,502	1,129,341
411	FT1 Large Low	650,724	627,437	607,639	589,396	582,202	575,326	568,446	560,801	556,033	549,752
412	TSS Large Low Load	70,115	80,501	91,264	98,456	102,803	108,387	115,983	124,213	132,714	139,829
413	C&I Low Load - Extra Large	102,993	113,583	124,287	133,043	136,632	138,176	141,261	145,016	148,269	150,539
414	FT2 Exlarge Low	47,280	51,652	56,071	59,683	61,159	61,796	63,068	64,617	65,958	66,898
415	FT1 Exlarge Low	297,272	300,876	300,755	300,810	301,587	302,824	304,801	306,408	307,897	309,076
416	TSS Extra Large Low Load	0	0	0	0	0	0	0	0	0	0
417	C&I High Load - Large	208,107	207,982	207,865	207,753	207,639	207,523	207,412	207,305	207,201	207,183
418	FT2 Large High	455,243	494,628	535,583	565,123	580,295	598,282	621,613	648,576	675,854	690,803
419	FT1 Large High	311,649	311,461	311,286	311,118	310,947	310,774	310,607	310,447	310,291	310,262
420	TSS Large High Load	26,418	26,402	26,387	26,373	26,358	26,344	26,330	26,316	26,303	26,301
421	C&I High Load - Extra Large	260,826	298,010	334,911	362,671	373,231	379,636	390,839	403,804	415,084	419,784
422	FT2 Exlarge High	418,681	418,681	418,681	418,681	418,681	418,681	418,681	418,681	418,681	418,681
423	FT1 Exlarge High	1,555,770	1,555,770	1,555,770	1,555,770	1,555,770	1,555,770	1,555,770	1,555,770	1,555,770	1,555,770
424	TSS Extra Large High Load	32,645	32,645	32,645	32,645	32,645	32,645	32,645	32,645	32,645	32,645
443	FT2 Small	116,698	162,870	216,226	261,461	280,064	291,749	312,108	336,872	359,129	369,283
444	TSS Small	2,326	4,452	6,985	8,917	9,939	11,251	13,196	15,506	18,011	19,206
	TOTAL	33,961,425	34,428,634	35,072,178	35,649,319	36,028,565	36,289,854	36,529,714	36,922,512	37,298,053	37,683,900
RH	Residential Heating	18,923,366	19,036,542	19,240,712	19,433,827	19,601,895	19,738,135	19,817,006	19,976,561	20,130,488	20,335,541
RN	Residential Non-heating	701,533	687,418	673,763	664,503	657,875	648,940	637,841	626,204	614,164	606,006
CH	Comm & Ind Heating	11,067,189	11,359,096	11,734,575	12,070,855	12,263,230	12,373,124	12,510,971	12,716,202	12,911,572	13,080,926
CN	Comm & Ind Non-heating	3,269,338	3,345,578	3,423,127	3,480,134	3,505,565	3,529,654	3,563,895	3,603,544	3,641,829	3,661,427
	TOTAL	33,961,425	34,428,634	35,072,178	35,649,319	36,028,565	36,289,854	36,529,714	36,922,512	37,298,053	37,683,900
	ANNUAL CHANGE										
	Residential Heating		113,177	204,170	193,115	168,068	136,241	78,871	159,555	153,927	205,054
	Residential Non-heating		-14,115	-13,655	-9,260	-6,628	-8,935	-11,099	-11,637	-12,041	-8,158
	Comm & Ind Heating		291,906	375,480	336,279	192,375	109,895	137,847	205,231	195,370	169,354
	Comm & Ind Non-heating		76,240	77,549	57,007	25,431	24,089	34,241	39,649	38,285	19,598
	TOTAL		467,208	643,544	577,141	379,246	261,290	239,860	392,798	375,541	385,847
	ANNUAL AVERAGE CHANGE										
	Residential Heating										156,908
	Residential Non-heating										-10,614
	Comm & Ind Heating										223,749
	Comm & Ind Non-heating										43,566
	TOTAL										413,608
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		0.6%	1.1%	1.0%	0.9%	0.7%	0.4%	0.8%	0.8%	1.0%
	Residential Non-heating		-2.0%	-2.0%	-1.4%	-1.0%	-1.4%	-1.7%	-1.8%	-1.9%	-1.3%
	Comm & Ind Heating		2.6%	3.3%	2.9%	1.6%	0.9%	1.1%	1.6%	1.5%	1.3%
	Comm & Ind Non-heating		2.3%	2.3%	1.7%	0.7%	0.7%	1.0%	1.1%	1.1%	0.5%
	TOTAL		1.4%	1.9%	1.6%	1.1%	0.7%	0.7%	1.1%	1.0%	1.0%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										0.8%
	Residential Non-heating										-1.6%
	Comm & Ind Heating										1.9%
	Comm & Ind Non-heating										1.3%
	TOTAL										1.2%

Narragansett Electric Company d/b/a NATIONAL GRID
Forecasted Number of Customers by Rate Code at End of Planning Year (2015/16 - 2024/25)

Rate Code	Rate Code Name	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
400	Residential Heating	194,887	197,696	199,847	201,065	202,212	204,002	205,908	207,970	210,181	212,443
401	Residential Non-Heating	21,198	20,744	20,396	20,199	20,014	19,724	19,416	19,083	18,725	18,361
402	Residential Low Income Heating	19,885	19,129	18,551	18,223	17,914	17,433	16,920	16,365	15,770	15,181
403	Residential Low Income Non-Heating	440	435	433	419	396	372	351	332	312	294
404	C&I Small	18,640	18,977	19,243	19,460	19,653	19,926	20,209	20,487	20,753	21,019
405	C&I Medium	3,080	3,131	3,180	3,206	3,214	3,226	3,243	3,261	3,276	3,292
406	FT2 Medium	1,319	1,362	1,406	1,449	1,492	1,536	1,579	1,623	1,666	1,710
407	FT1 Medium	387	387	386	387	387	388	389	389	390	391
408	TSS Medium	191	243	292	318	326	338	355	373	388	404
409	C&I Low Load - Large	114	118	121	122	123	124	125	126	127	128
410	FT2 Large Low	188	196	210	215	212	210	211	213	215	217
411	FT1 Large Low	103	100	97	95	95	94	93	92	91	90
412	TSS Large Low Load	16	19	21	22	23	24	26	28	30	32
413	C&I Low Load - Extra Large	8	9	9	10	10	10	10	11	11	11
414	FT2 Exlarge Low	3	4	4	4	4	4	4	4	4	5
415	FT1 Exlarge Low	9	9	9	9	9	9	9	9	9	9
416	TSS Extra Large Low Load	0	0	0	0	0	0	0	0	0	0
417	C&I High Load - Large	38	38	38	38	38	38	38	38	38	38
418	FT2 Large High	68	71	74	75	77	79	81	84	87	89
419	FT1 Large High	46	46	46	46	46	46	46	46	46	46
420	TSS Large High Load	3	3	3	3	3	3	3	3	3	3
421	C&I High Load - Extra Large	6	7	7	8	8	8	8	9	9	9
422	FT2 Exlarge High	13	13	13	13	13	13	13	13	13	13
423	FT1 Exlarge High	32	32	32	32	32	32	32	32	32	32
424	TSS Extra Large High Load	1	1	1	1	1	1	1	1	1	1
443	FT2 Small	334	378	420	442	449	460	475	490	503	517
444	TSS Small	11	17	21	23	25	28	31	35	39	44
	TOTAL	261,021	263,163	264,858	265,883	266,775	268,129	269,579	271,115	272,721	274,379
RH	Residential Heating	214,772	216,825	218,398	219,288	220,127	221,435	222,828	224,335	225,952	227,624
RN	Residential Non-heating	21,638	21,179	20,829	20,618	20,409	20,096	19,767	19,414	19,037	18,655
CH	Comm & Ind Heating	24,404	24,948	25,418	25,761	26,021	26,378	26,761	27,140	27,503	27,867
CN	Comm & Ind Non-heating	206	211	214	216	218	220	223	225	228	232
	TOTAL	261,021	263,163	264,858	265,883	266,775	268,129	269,579	271,115	272,721	274,379
	ANNUAL CHANGE										
	Residential Heating		2,053	1,573	890	839	1,308	1,394	1,507	1,617	1,673
	Residential Non-heating		-459	-350	-210	-209	-313	-329	-353	-377	-382
	Comm & Ind Heating		544	470	343	260	357	383	379	363	364
	Comm & Ind Non-heating		4	3	2	2	2	3	3	3	3
	TOTAL		2,142	1,696	1,025	891	1,355	1,450	1,536	1,606	1,658
	ANNUAL AVERAGE CHANGE										
	Residential Heating										1,428
	Residential Non-heating										-331
	Comm & Ind Heating										385
	Comm & Ind Non-heating										3
	TOTAL										1,484
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		1.0%	0.7%	0.4%	0.4%	0.6%	0.6%	0.7%	0.7%	0.7%
	Residential Non-heating		-2.1%	-1.7%	-1.0%	-1.0%	-1.5%	-1.6%	-1.8%	-1.9%	-2.0%
	Comm & Ind Heating		2.2%	1.9%	1.4%	1.0%	1.4%	1.5%	1.4%	1.3%	1.3%
	Comm & Ind Non-heating		2.1%	1.6%	0.9%	0.7%	1.1%	1.2%	1.3%	1.3%	1.3%
	TOTAL		0.8%	0.6%	0.4%	0.3%	0.5%	0.5%	0.6%	0.6%	0.6%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										0.6%
	Residential Non-heating										-1.6%
	Comm & Ind Heating										1.5%
	Comm & Ind Non-heating										1.3%
	TOTAL										0.6%

Narragansett Electric Company d/b/a NATIONAL GRID
Forecasted Retail Use Per Customers by Rate Code in Dth/customer (2015/16 - 2024/25)

		235	236	237	238	239	240	241	242	243	244
Rate Code	Rate Code Name	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
400	Residential Heating	88.2	87.9	88.3	88.9	89.4	89.6	89.4	89.6	89.7	89.8
401	Residential Non-Heating	31.9	31.9	31.8	31.7	31.7	31.8	31.9	31.9	31.9	32.2
402	Residential Low Income Heating	87.2	86.8	86.1	85.2	84.6	84.1	82.9	82.1	81.5	82.4
403	Residential Low Income Non-Heating	59.1	57.6	56.4	56.7	57.3	56.3	54.9	53.9	52.8	53.2
404	C&I Small	125.4	124.3	124.1	123.9	123.9	123.1	122.2	122.1	121.9	122.1
405	C&I Medium	1039.0	1039.9	1042.5	1056.1	1068.4	1073.0	1072.8	1076.2	1078.0	1081.4
406	FT2 Medium	1301.3	1313.6	1329.3	1338.3	1346.1	1354.8	1363.8	1376.4	1390.0	1387.2
407	FT1 Medium	1752.6	1745.2	1740.3	1730.1	1710.3	1677.2	1651.3	1627.9	1608.6	1594.5
408	TSS Medium	1073.5	1115.7	1174.0	1267.2	1308.0	1283.3	1272.0	1280.9	1286.7	1274.7
409	C&I Low Load - Large	5325.3	5319.9	5335.4	5423.9	5495.1	5511.6	5505.7	5523.1	5536.0	5553.3
410	FT2 Large Low	5500.8	5319.2	5249.6	5344.4	5418.8	5333.1	5248.4	5223.9	5205.2	5210.4
411	FT1 Large Low	6327.8	6288.3	6272.8	6182.8	6138.3	6113.9	6107.2	6092.2	6101.3	6095.6
412	TSS Large Low Load	4309.7	4289.0	4412.3	4523.0	4511.0	4445.3	4447.4	4449.9	4441.2	4381.4
413	C&I Low Load - Extra Large	13188.4	13220.8	13313.8	13674.1	13868.0	13758.3	13707.9	13723.2	13725.7	13629.1
414	FT2 Exlarge Low	14293.1	14326.8	14420.5	14779.2	14971.6	14863.3	14814.4	14830.8	14834.2	14739.0
415	FT1 Exlarge Low	33213.4	33274.9	33356.7	33275.3	33244.7	33211.8	33174.7	33176.1	33155.2	33074.3
416	TSS Extra Large Low Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
417	C&I High Load - Large	5476.5	5473.2	5470.1	5467.2	5464.2	5461.1	5458.2	5455.4	5452.7	5452.2
418	FT2 Large High	6737.3	6960.2	7262.9	7509.2	7567.2	7581.6	7647.4	7735.0	7804.2	7724.8
419	FT1 Large High	6775.0	6770.9	6767.1	6763.4	6759.7	6756.0	6752.3	6748.9	6745.5	6744.8
420	TSS Large High Load	8805.9	8800.6	8795.7	8791.0	8786.1	8781.2	8776.5	8772.0	8767.6	8766.9
421	C&I High Load - Extra Large	44817.5	45073.3	45472.1	46708.0	47310.5	46971.5	46820.9	46882.9	46896.3	46142.4
422	FT2 Exlarge High	32206.2	32206.2	32206.2	32206.2	32206.2	32206.2	32206.2	32206.2	32206.2	32206.2
423	FT1 Exlarge High	48617.8	48617.8	48617.8	48617.8	48617.8	48617.8	48617.8	48617.8	48617.8	48617.8
424	TSS Extra Large High Load	32644.6	32644.6	32644.6	32644.6	32644.6	32644.6	32644.6	32644.6	32644.6	32644.6
443	FT2 Small	349.7	430.9	514.8	591.1	623.4	634.2	657.3	688.0	714.1	714.7
444	TSS Small	202.4	260.9	331.1	387.9	402.2	403.3	421.0	440.9	457.7	439.1
	AVERAGE	130.1	130.8	132.4	134.1	135.1	135.3	135.5	136.2	136.8	137.3
RH	Residential Heating	88.1	87.8	88.1	88.6	89.0	89.1	88.9	89.0	89.1	89.3
RN	Residential Non-heating	32.4	32.5	32.3	32.2	32.2	32.3	32.3	32.3	32.3	32.5
CH	Comm & Ind Heating	453.5	455.3	461.7	468.6	471.3	469.1	467.5	468.5	469.5	469.4
CN	Comm & Ind Non-heating	15840.6	15880.1	15987.9	16110.1	16112.0	16044.3	16008.0	15982.9	15941.3	15814.5
	AVERAGE	130.1	130.8	132.4	134.1	135.1	135.3	135.5	136.2	136.8	137.3
	ANNUAL CHANGE										
	Residential Heating		-0.3	0.3	0.5	0.4	0.1	-0.2	0.1	0.0	0.2
	Residential Non-heating		0.0	-0.1	-0.1	0.0	0.1	0.0	0.0	0.0	0.2
	Comm & Ind Heating		1.8	6.4	6.9	2.7	-2.2	-1.6	1.0	0.9	-0.1
	Comm & Ind Non-heating		39.6	107.7	122.2	1.9	-67.7	-36.3	-25.1	-41.6	-126.8
	AVERAGE		0.7	1.6	1.7	1.0	0.3	0.2	0.7	0.6	0.6
	ANNUAL AVERAGE CHANGE										
	Residential Heating										0.1
	Residential Non-heating										0.0
	Comm & Ind Heating										1.8
	Comm & Ind Non-heating										-2.9
	AVERAGE										0.8
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		-0.4%	0.3%	0.6%	0.5%	0.1%	-0.2%	0.1%	0.0%	0.3%
	Residential Non-heating		0.1%	-0.3%	-0.4%	0.0%	0.2%	-0.1%	0.0%	0.0%	0.7%
	Comm & Ind Heating		0.4%	1.4%	1.5%	0.6%	-0.5%	-0.3%	0.2%	0.2%	0.0%
	Comm & Ind Non-heating		0.2%	0.7%	0.8%	0.0%	-0.4%	-0.2%	-0.2%	-0.3%	-0.8%
	AVERAGE		0.6%	1.2%	1.3%	0.7%	0.2%	0.1%	0.5%	0.4%	0.4%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										0.2%
	Residential Non-heating										0.0%
	Comm & Ind Heating										0.4%
	Comm & Ind Non-heating										0.0%
	AVERAGE										0.6%

Narragansett Electric Company d/b/a NATIONAL GRID
Historical Actual Retail Gas Deliveries by Rate Code in Dth (2010/11 - 2014/15)

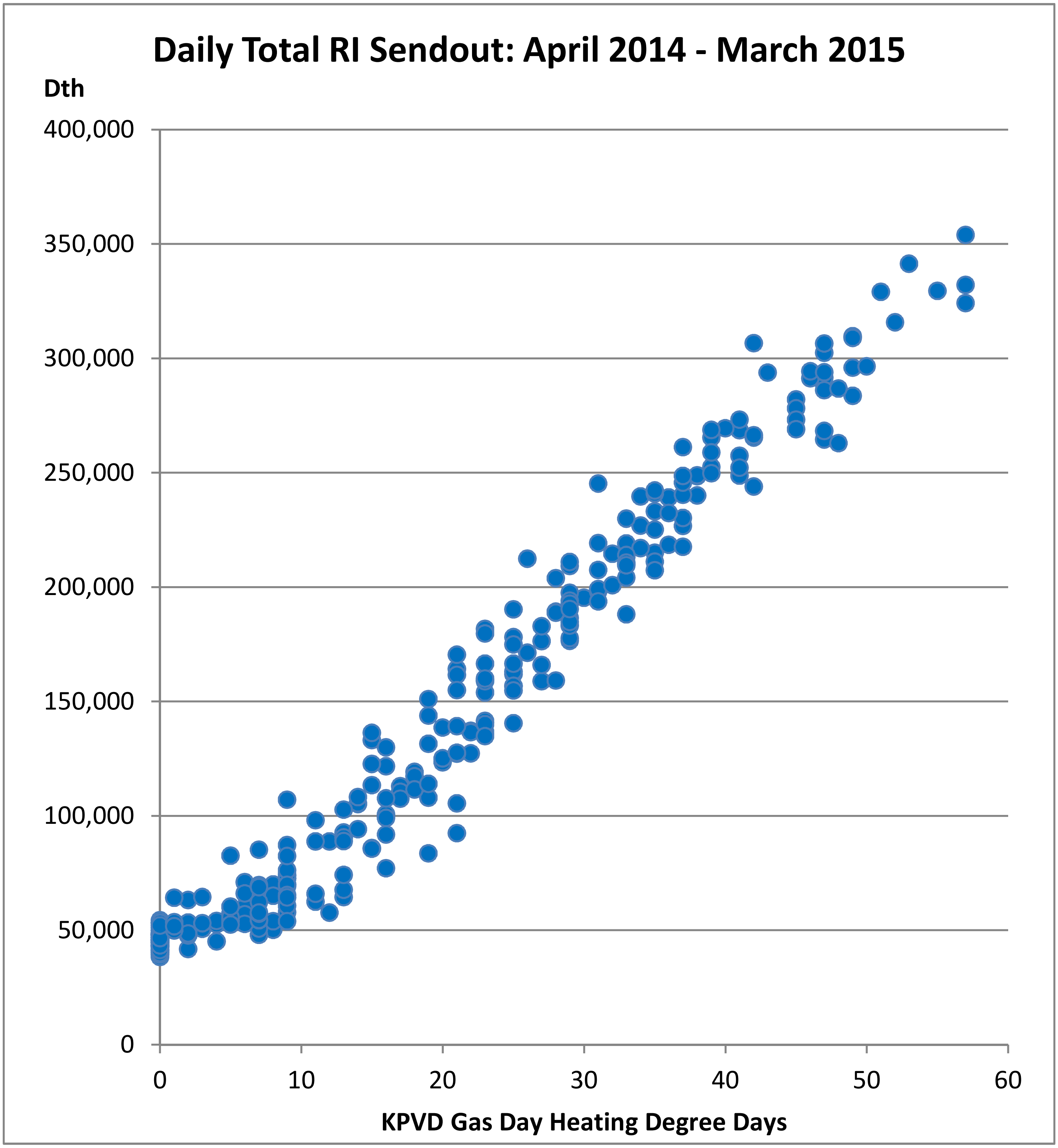
		227	228	229	230	231
Rate Code	Rate Code Name	2010/11	2011/12	2012/13	2013/14	2014/15
400	Residential Heating	16,043,617	13,378,440	15,761,597	17,808,459	18,517,524
401	Residential Non-Heating	584,266	583,069	719,860	903,566	721,250
402	Residential Low Income Heating	1,694,618	1,405,019	1,553,639	1,762,734	1,877,765
403	Residential Low Income Non-Heating	22,084	18,330	27,023	41,506	29,186
404	C&I Small	2,375,884	1,839,290	2,272,398	2,643,413	2,688,820
405	C&I Medium	3,185,792	2,597,447	2,955,075	3,320,005	3,429,466
406	FT2 Medium	1,273,193	1,175,305	1,494,845	1,708,274	1,715,783
407	FT1 Medium	715,274	634,556	693,059	727,117	712,648
408	TSS Medium	21,786	31,925	44,581	106,147	209,596
409	C&I Low Load - Large	633,241	548,670	569,263	716,781	741,405
410	FT2 Large Low	824,234	757,158	1,033,729	1,160,990	1,169,391
411	FT1 Large Low	886,694	731,944	734,171	818,917	775,253
412	TSS Large Low Load	13,220	37,156	32,018	51,315	55,566
413	C&I Low Load - Extra Large	52,467	90,943	104,776	104,619	91,116
414	FT2 Exlarge Low	65,380	41,009	29,199	72,734	65,476
415	FT1 Exlarge Low	248,381	228,422	289,169	204,003	314,001
416	TSS Extra Large Low Load	4,884	1,719	6,880	2,651	4,507
417	C&I High Load - Large	266,526	236,670	288,138	280,988	207,355
418	FT2 Large High	258,903	230,338	333,694	420,185	486,714
419	FT1 Large High	362,833	324,113	369,384	352,511	329,203
420	TSS Large High Load	6,394	4,287	3,318	19,341	28,200
421	C&I High Load - Extra Large	162,962	231,352	294,293	360,061	364,347
422	FT2 Exlarge High	147,449	130,074	158,336	174,461	230,777
423	FT1 Exlarge High	1,105,905	1,150,101	1,227,190	1,339,861	1,661,480
424	TSS Extra Large High Load	0	1,254	9,105	-6,321	38,153
443	FT2 Small	0	123	12,388	37,000	74,602
444	TSS Small	0	0	276	1,799	8,950
	TOTAL	30,955,983	26,408,713	31,017,406	35,133,118	36,548,534
RH	Residential Heating	17,738,236	14,783,459	17,315,237	19,571,193	20,395,289
RN	Residential Non-heating	606,350	601,399	746,883	945,072	750,436
CH	Comm & Ind Heating	10,300,428	8,715,666	10,271,827	11,675,765	12,056,580
CN	Comm & Ind Non-heating	2,310,970	2,308,189	2,683,459	2,941,088	3,346,230
	TOTAL	30,955,983	26,408,713	31,017,406	35,133,118	36,548,534
	ANNUAL CHANGE					
	Residential Heating		-2,954,777	2,531,778	2,255,956	824,096
	Residential Non-heating		-4,951	145,484	198,189	-194,636
	Comm & Ind Heating		-1,584,762	1,556,161	1,403,938	380,815
	Comm & Ind Non-heating		-2,781	375,270	257,629	405,141
	TOTAL		-4,547,271	4,608,693	4,115,712	1,415,416

Narragansett Electric Company d/b/a NATIONAL GRID
Historical Number of Customers by Rate Class at End of Planning Year (2010/11 - 2014/15)

Rate Code	Rate Code Name	2010/11	2011/12	2012/13	2013/14	2014/15
400	Residential Heating	175,586	181,097	184,996	186,204	191,969
401	Residential Non-Heating	26,239	25,563	25,545	25,317	21,670
402	Residential Low Income Heating	20,827	19,363	19,508	20,292	20,670
403	Residential Low Income Non-Heating	331	392	495	630	448
404	C&I Small	17,866	17,959	18,191	18,217	18,223
405	C&I Medium	2,888	2,924	3,024	3,078	3,031
406	FT2 Medium	1,046	1,162	1,249	1,221	1,275
407	FT1 Medium	427	417	406	388	386
408	TSS Medium	23	30	39	122	142
409	C&I Low Load - Large	115	115	121	122	111
410	FT2 Large Low	151	171	179	187	186
411	FT1 Large Low	137	117	120	117	106
412	TSS Large Low Load	3	7	7	6	14
413	C&I Low Load - Extra Large	5	5	6	6	7
414	FT2 Exlarge Low	3	1	5	4	3
415	FT1 Exlarge Low	9	10	9	7	9
416	TSS Extra Large Low Load	0	1	0	1	0
417	C&I High Load - Large	42	53	51	36	38
418	FT2 Large High	39	57	60	67	64
419	FT1 Large High	51	58	52	49	46
420	TSS Large High Load	0	2	1	3	3
421	C&I High Load - Extra Large	7	6	6	9	5
422	FT2 Exlarge High	5	8	6	7	13
423	FT1 Exlarge High	30	31	28	33	32
424	TSS Extra Large High Load	0	0	1	1	1
443	FT2 Small	0	13	114	135	292
444	TSS Small	0	0	2	41	6
	TOTAL	245,830	249,562	254,221	256,300	258,751
RH	Residential Heating	196,413	200,460	204,504	206,496	212,639
RN	Residential Non-heating	26,570	25,955	26,040	25,947	22,118
CH	Comm & Ind Heating	22,673	22,932	23,472	23,652	23,792
CN	Comm & Ind Non-heating	174	215	205	205	202
	TOTAL	245,830	249,562	254,221	256,300	258,751
	ANNUAL CHANGE					
	Residential Heating		4,047	4,044	1,992	6,143
	Residential Non-heating		-615	85	-93	-3,829
	Comm & Ind Heating		259	540	180	140
	Comm & Ind Non-heating		41	-10	0	-3
	TOTAL		3,732	4,659	2,079	2,451

Narragansett Electric Company d/b/a NATIONAL GRID
Historical Retail Use Per Customer by Rate Code in Dth/customer (2010/11 - 2014/15)

Rate Code	Rate Code Name	2010/11	2011/12	2012/13	2013/14	2014/15
		235	236	237	238	239
400	Residential Heating	91.4	73.9	85.2	95.6	96.5
401	Residential Non-Heating	22.3	22.8	28.2	35.7	33.3
402	Residential Low Income Heating	81.4	72.6	79.6	86.9	90.8
403	Residential Low Income Non-Heating	66.7	46.8	54.6	65.9	65.1
404	C&I Small	133.0	102.4	124.9	145.1	147.6
405	C&I Medium	1103.1	888.3	977.2	1078.6	1131.3
406	FT2 Medium	1217.2	1011.5	1196.8	1399.1	1345.5
407	FT1 Medium	1675.1	1521.7	1707.0	1874.0	1844.5
408	TSS Medium	947.2	1064.2	1143.1	870.1	1471.5
409	C&I Low Load - Large	5506.4	4771.0	4704.7	5875.3	6662.4
410	FT2 Large Low	5458.5	4427.8	5775.0	6208.5	6285.7
411	FT1 Large Low	6472.2	6255.9	6118.1	6999.3	7332.0
412	TSS Large Low Load	4406.6	5308.0	4574.0	8552.6	4064.2
413	C&I Low Load - Extra Large	10493.4	18188.5	17462.7	17436.4	12892.2
414	FT2 Exlarge Low	21793.2	41009.4	5839.7	18183.5	21640.1
415	FT1 Exlarge Low	27597.9	22842.2	32129.9	29143.3	35352.7
416	TSS Extra Large Low Load	0.0	1718.7	0.0	2651.3	0.0
417	C&I High Load - Large	6345.8	4465.5	5649.8	7805.2	5456.7
418	FT2 Large High	6638.5	4041.0	5561.6	6271.4	7612.1
419	FT1 Large High	7114.4	5588.1	7103.5	7194.1	7156.6
420	TSS Large High Load	0.0	2143.4	3318.0	6447.1	9400.1
421	C&I High Load - Extra Large	23280.4	38558.7	49048.9	40006.8	71886.1
422	FT2 Exlarge High	29489.7	16259.2	26389.3	24923.0	17752.1
423	FT1 Exlarge High	36863.5	37100.0	43828.2	40601.9	51921.3
424	TSS Extra Large High Load	0.0	0.0	9104.9	-6320.8	38152.7
443	FT2 Small	0.0	9.5	108.7	274.1	255.6
444	TSS Small	0.0	0.0	137.9	43.9	1585.5
	TOTAL	125.9	105.8	122.0	137.1	141.2
RH	Residential Heating	90.3	73.7	84.7	94.8	95.9
RN	Residential Non-heating	22.8	23.2	28.7	36.4	33.9
CH	Comm & Ind Heating	454.3	380.1	437.6	493.6	506.8
CN	Comm & Ind Non-heating	13281.4	10735.8	13090.0	14346.8	16564.9
	TOTAL	125.9	105.8	122.0	137.1	141.2
	ANNUAL CHANGE					
	Residential Heating		-16.6	10.9	10.1	1.1
	Residential Non-heating		0.4	5.5	7.7	-2.5
	Comm & Ind Heating		-74.2	57.6	56.0	13.1
	Comm & Ind Non-heating		-2545.7	2354.3	1256.7	2218.1
	TOTAL		-20.1	16.2	15.1	4.2


Daily Total RI Sendout: April 2014 - March 2015
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
0
10
20
30
40
50
60
KPVD Gas Day Heating Degree Days

National Grid Rhode Island **Chart III-E-1**

2016 Long Range Plan

Assumptions:

Mean Peak Day =	**55.43**	**HDD**
Std Dev Peak Day =	**5.42**	**HDD**
Heating Increment =	**5,456.13**	**MMBtu/HDD**
No. of Firm Customers =	**262,667**	

HDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	HDD Excess	Delta Supply (MMBtu)	Requirements Of An Average Customer At HDD Level (MMBtu/cust)	Equivalent Number of Customers
55.4	0.5000	0.5000	2.00	0.0	0	1.15	0
56.0	0.5423	0.4577	2.18	0.6	3,137	1.16	2,697
57.0	0.6144	0.3856	2.59	1.6	8,593	1.18	7,258
58.0	0.6828	0.3172	3.15	2.6	14,050	1.20	11,662
59.0	0.7454	0.2546	3.93	3.6	19,506	1.23	15,916
60.0	0.8009	0.1991	5.02	4.6	24,962	1.25	20,028
61.0	0.8484	0.1516	6.59	5.6	30,418	1.27	24,006
62.0	0.8876	0.1124	8.90	6.6	35,874	1.29	27,855
63.0	0.9191	0.0809	12.35	7.6	41,330	1.31	31,583
64.0	0.9433	0.0567	17.65	8.6	46,786	1.33	35,193
65.0	0.9615	0.0385	25.96	9.6	52,242	1.35	38,693
66.0	0.9746	0.0254	39.33	10.6	57,699	1.37	42,086
67.0	0.9837	0.0163	61.41	11.6	63,155	1.39	45,379
68.0	0.9899	0.0101	98.86	12.6	68,611	1.41	48,574
69.0	0.9939	0.0061	164.12	13.6	74,067	1.43	51,677
70.0	0.9964	0.0036	281.05	14.6	79,523	1.45	54,691
71.0	0.9980	0.0020	496.60	15.6	84,979	1.47	57,620
72.0	0.9989	0.0011	905.60	16.6	90,435	1.50	60,468
73.0	0.9994	0.0006	1704.75	17.6	95,892	1.52	63,238
74.0	0.9997	0.0003	3313.24	18.6	101,348	1.54	65,933
75.0	0.9998	0.0002	6649.43	19.6	106,804	1.56	68,556
76.0	0.9999	0.0001	13782.24	20.6	112,260	1.58	71,110
77.0	1.0000	0.0000	29506.38	21.6	117,716	1.60	73,598
78.0	1.0000	0.0000	65256.63	22.6	123,172	1.62	76,022
66.8	0.9822	0.0178	56.04	**(EDD Level MINUS Mean Peak)**	**(EDD Excess TIMES Heating Increment) (MMBtu)**	**(Heating Increment DIVIDED BY No. of Firm Customers TIMES EDD Level)**	**(Delta Supply DIVIDED BY Requirements of Average Customer)**
68.0	0.9899	0.0101	98.86				

National Grid Rhode Island **Chart III-E-2**
2016 Long Range Plan

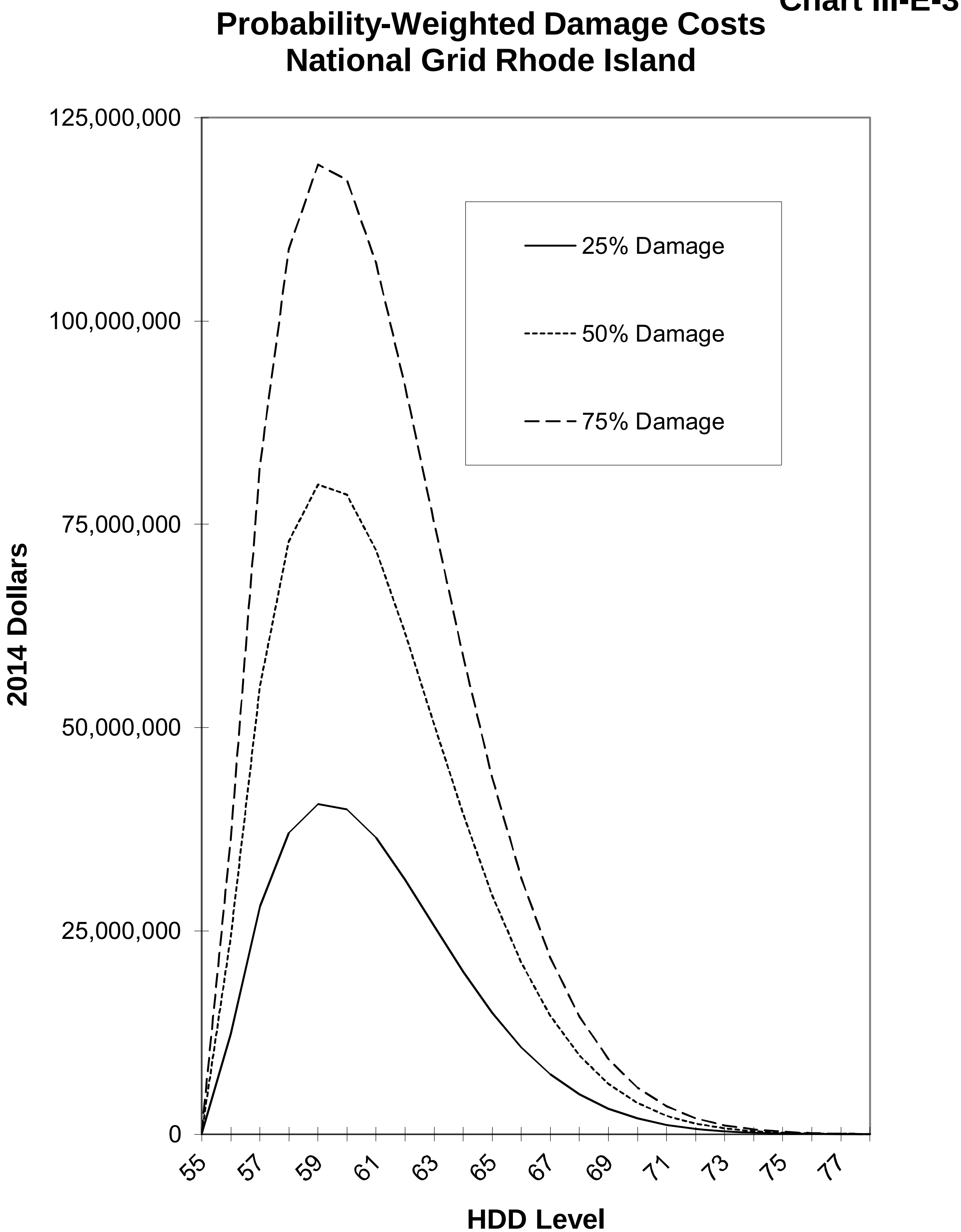
Assumptions:

Mean Peak Day =	**55.43**	**EDD**
Std Dev Peak Day =	**5.42**	**EDD**
SCC Heating Increment =	**5,456.13**	**MMBtu/EDD**
No. of SCC Customers =	**262,667**	
	2014 dollars	
Relight Costs =	**$1,069.00**	**/customer**
Freeze-Up Damages =	**$41,794.39**	**/customer**
Total =	**$42,863.39**	**/customer**
Feb 2015:		
Residential Customers	**237,899**	
Comm/Ind Customers	**24,768**	
Total Customers	**262,667**	
Percent C&I of Total	**9.4%**	
Cost of Interruption/Day = (2014 dollars)	**$82,035,574**	

EDD Level	**Probability Of Exceeding (1-p)**	**Equivalent Number of Customers**	**Residential Customers**	**Comm/Ind Customers**	**Cost Of Interruption to Comm/Ind Customers**	**Probability-Weighted Cost Of Damages Given X% of Residential Customers With Damages PLUS Cost of Interruption to Comm/Ind Customers (2014 dollars)**		
						25%	**50%**	**75%**
55.4	0.5000	0	0	0	$0	0	0	0
56.0	0.4577	2,697	2,443	254	$842,330	12,366,739	24,347,926	36,329,112
57.0	0.3856	7,258	6,574	684	$2,266,772	28,035,336	55,196,627	82,357,919
58.0	0.3172	11,662	10,562	1,100	$3,642,097	37,058,167	72,960,988	108,863,810
59.0	0.2546	15,916	14,415	1,501	$4,970,800	40,590,516	79,915,560	119,240,605
60.0	0.1991	20,028	18,140	1,889	$6,255,213	39,949,480	78,653,473	117,357,467
61.0	0.1516	24,006	21,742	2,264	$7,497,514	36,465,648	71,794,425	107,123,201
62.0	0.1124	27,855	25,229	2,627	$8,699,740	31,351,858	61,726,274	92,100,690
63.0	0.0809	31,583	28,605	2,978	$9,863,801	25,608,810	50,419,226	75,229,643
64.0	0.0567	35,193	31,875	3,319	$10,991,485	19,976,864	39,330,920	58,684,975
65.0	0.0385	38,693	35,044	3,649	$12,084,471	14,932,516	29,399,488	43,866,460
66.0	0.0254	42,086	38,118	3,969	$13,144,336	10,719,752	21,105,299	31,490,846
67.0	0.0163	45,379	41,100	4,279	$14,172,564	7,402,238	14,573,699	21,745,161
68.0	0.0101	48,574	43,994	4,580	$15,170,549	4,922,145	9,690,835	14,459,524
69.0	0.0061	51,677	46,804	4,873	$16,139,607	3,154,385	6,210,427	9,266,470
70.0	0.0036	54,691	49,534	5,157	$17,080,978	1,949,437	3,838,097	5,726,757
71.0	0.0020	57,620	52,187	5,433	$17,995,832	1,162,355	2,288,472	3,414,588
72.0	0.0011	60,468	54,766	5,702	$18,885,273	668,895	1,316,936	1,964,977
73.0	0.0006	63,238	57,275	5,963	$19,750,345	371,609	731,633	1,091,657
74.0	0.0003	65,933	59,716	6,217	$20,592,038	199,351	392,487	585,624
75.0	0.0002	68,556	62,092	6,464	$21,411,285	103,283	203,347	303,410
76.0	0.0001	71,110	64,405	6,705	$22,208,973	51,687	101,762	151,838
77.0	0.0000	73,598	66,658	6,940	$22,985,942	24,987	49,196	73,404
78.0	0.0000	76,022	68,853	7,168	$23,742,988	11,670	22,977	34,283

(Probability of Exceeding TIMES
[Comm/Ind Cost of Interruption PLUS
No. Of Residential Customers TIMES Percent TIMES
Total Damage Costs])

Chart III-E-3



Probability-Weighted Damage Costs
National Grid Rhode Island
125,000,000
100,000,000
75,000,000
50,000,000
25,000,000
0
2014 Dollars
25% Damage
50% Damage
75% Damage
55
57
59
61
63
65
67
69
71
73
75
77
HDD Level

National Grid Rhode Island
2016 Long Range Plan

Chart III-E-4

Assumptions:

Mean Peak Day = **55.43 EDD**
Std Dev Peak Day = **5.42 EDD**

2014 dollars

Cost of Incr. LNG Vaporization = **$69.79 /MMBtu**
Cost of New Pipeline Capacity = **$510.90 /MMBtu**

		Low Upgrade Costs Case	High Upgrade Costs Case
EDD Level	**Delta Supply (MMBtu)**	**LNG Vaporization Costs**	**Pipeline Capacity Costs**
55.4	0	$0	$0
56.0	3,137	$218,940	$1,602,834
57.0	8,593	$599,706	$4,390,371
58.0	14,050	$980,472	$7,177,909
59.0	19,506	$1,361,238	$9,965,446
60.0	24,962	$1,742,003	$12,752,984
61.0	30,418	$2,122,769	$15,540,521
62.0	35,874	$2,503,535	$18,328,059
63.0	41,330	$2,884,301	$21,115,596
64.0	46,786	$3,265,066	$23,903,133
65.0	52,242	$3,645,832	$26,690,671
66.0	57,699	$4,026,598	$29,478,208
67.0	63,155	$4,407,364	$32,265,746
68.0	68,611	$4,788,129	$35,053,283
69.0	74,067	$5,168,895	$37,840,821
70.0	79,523	$5,549,661	$40,628,358
71.0	84,979	$5,930,427	$43,415,895
72.0	90,435	$6,311,192	$46,203,433
73.0	95,892	$6,691,958	$48,990,970
74.0	101,348	$7,072,724	$51,778,508
75.0	106,804	$7,453,489	$54,566,045
76.0	112,260	$7,834,255	$57,353,583
77.0	117,716	$8,215,021	$60,141,120
78.0	123,172	$8,595,787	$62,928,657

Chart III-E-5

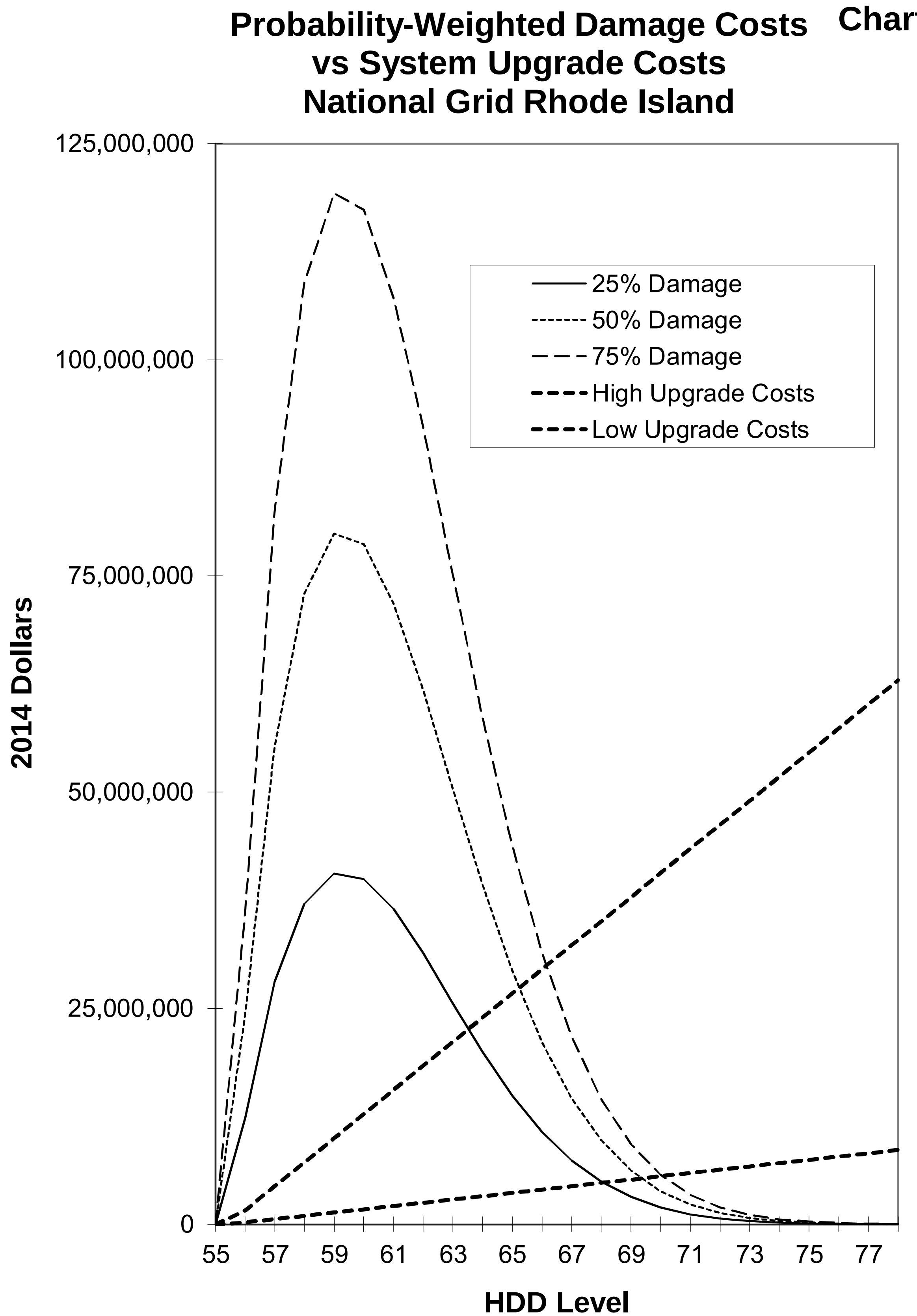
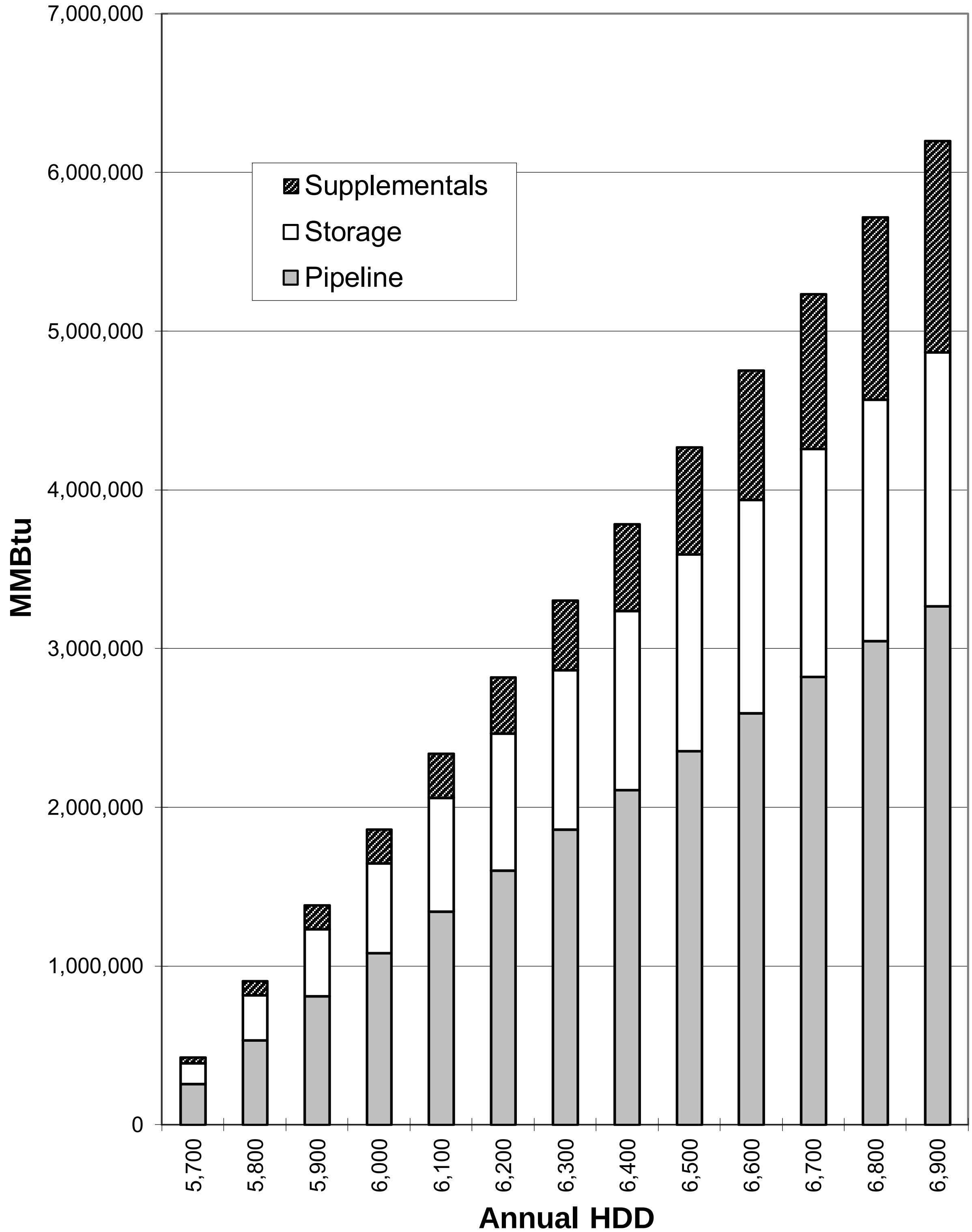

Probability-Weighted Damage Costs
vs System Upgrade Costs
National Grid Rhode Island
125,000,000
100,000,000
75,000,000
50,000,000
25,000,000
0
2014 Dollars
55
57
59
61
63
65
67
69
71
73
75
77
HDD Level
25% Damage
50% Damage
75% Damage
High Upgrade Costs
Low Upgrade Costs

Chart III-E-6

Supply Shortfall Versus Annual HDD Level of Design
National Grid Rhode Island



National Grid Rhode Island
2016 Long Range Plan

Chart III-E-7

Pipeline Shortfall At HDD Level Above 5,596 Normal Annual HDD
By Month

	Annual HDD Level													
	5,596	5,685	5,785	5,885	5,985	6,085	6,185	6,285	6,385	6,485	6,585	6,685	6,785	6,885
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	379	200,118	395,182	583,832
Oct	0	255,989	533,792	809,044	1,080,271	1,344,347	1,602,975	1,859,498	2,110,345	2,353,479	2,592,648	2,622,704	2,652,760	2,682,816
Total	0	255,989	533,792	809,044	1,080,271	1,344,347	1,602,975	1,859,498	2,110,345	2,353,479	2,593,027	2,822,822	3,047,942	3,266,648

Storage Shortfall At HDD Level Above 5,596 Normal Annual HDD
By Month

	Annual HDD Level													
	5,596	5,685	5,785	5,885	5,985	6,085	6,185	6,285	6,385	6,485	6,585	6,685	6,785	6,885
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	7,121	79,999	153,658	223,208	282,819	343,745	398,321	450,153	493,128	532,502
Feb	0	48,317	172,535	289,864	400,334	450,208	500,797	551,488	595,778	633,915	666,318	691,259	716,764	739,786
Mar	0	84,090	109,114	134,852	160,591	186,133	208,446	229,661	247,711	264,049	278,987	295,822	312,825	326,741
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	2,661
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	132,407	281,648	424,716	568,046	716,341	862,901	1,004,357	1,126,308	1,241,710	1,343,626	1,437,234	1,522,718	1,601,690

Supplementals Shortfall At HDD Level Above 5,596 Normal Annual HDD
By Month

	Annual HDD Level													
	5,596	5,685	5,785	5,885	5,985	6,085	6,185	6,285	6,385	6,485	6,585	6,685	6,785	6,885
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	8,689	51,142	95,897
Jan	0	0	0	44,276	95,610	149,367	208,945	275,165	355,462	440,243	534,960	629,930	700,124	772,407
Feb	0	37,156	88,261	103,813	116,191	128,568	140,946	155,170	176,577	204,137	237,431	279,845	325,510	376,136
Mar	0	0	0	0	0	197	3,623	8,146	16,589	28,659	42,129	55,599	69,628	87,235
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	37,156	88,261	148,089	211,801	278,132	353,514	438,481	548,629	673,039	814,520	974,063	1,146,405	1,331,675

National Grid Rhode Island **Chart III-E-8**
2016 Long Range Plan

Assumptions:

Mean Annual HDD = 5,596.6 EDD
Std Dev Annual HDD = 358.6 EDD

EDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	EDD Excess	Delta Supply (MMBtu) Pipeline	Storage	Supplementals	Total
5,700	0.6135	0.3865	2.59	103.5	255,989	132,407	37,156	425,551
5,800	0.7147	0.2853	3.51	203.5	533,792	281,648	88,261	903,701
5,900	0.8013	0.1987	5.03	303.5	809,044	424,716	148,089	1,381,850
6,000	0.8697	0.1303	7.67	403.5	1,080,271	568,046	211,801	1,860,118
6,100	0.9198	0.0802	12.47	503.5	1,344,347	716,341	278,132	2,338,820
6,200	0.9538	0.0462	21.64	603.5	1,602,975	862,901	353,514	2,819,390
6,300	0.9751	0.0249	40.15	703.5	1,859,498	1,004,357	438,481	3,302,336
6,400	0.9875	0.0125	79.79	803.5	2,110,345	1,126,308	548,629	3,785,282
6,500	0.9941	0.0059	170.04	903.5	2,353,479	1,241,710	673,039	4,268,227
6,600	0.9974	0.0026	389.03	1,003.5	2,593,027	1,343,626	814,520	4,751,173
6,700	0.9990	0.0010	956.20	1,103.5	2,822,822	1,437,234	974,063	5,234,119
6,800	0.9996	0.0004	2526.84	1,203.5	3,047,942	1,522,718	1,146,405	5,717,064
6,900	0.9999	0.0001	7183.42	1,303.5	3,266,648	1,601,690	1,331,675	6,200,013
6,280	0.9717	0.0283	35.28					
6,168	0.9445	0.0555	18.01					
				(EDD Level MINUS Mean Peak)	**(EDD Excess TIMES Heating Increment) (MMBtu)**			

National Grid Rhode Island **Chart III-E-9**
2016 Long Range Plan

Assumptions:

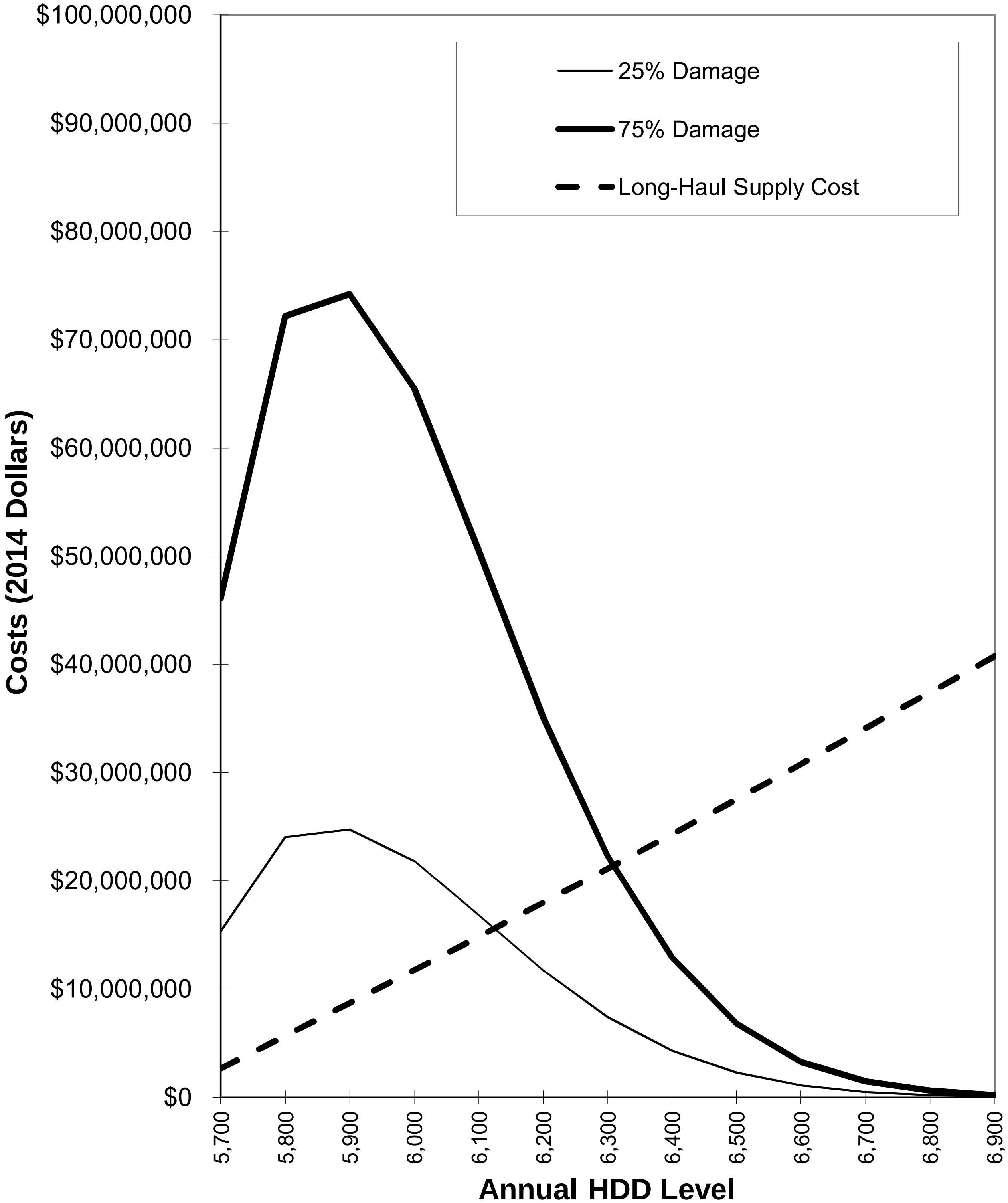
Mean Annual HDD =	**5,596.6**	
Std Dev Annual HDD =	**358.6**	
Cost of Interruption/Day =	**$82,035,574**	(2014 dollars)
Peak Period Supply Cost	**$4.749**	**$/MMBtu**
Long-Haul Capacity Cost	**$593.26**	**$/MMBtu**
Offpeak Period Supply Cost	**$4.770**	
Short-Haul Capacity Cost	**$101.875**	**$/MMBtu**
Storage D1 Cost	**$18.480**	**$/MMBtu**
Storage D2 Cost	**$0.253**	**$/MMBtu**

					Costs in 2014 Dollars				**Costs in 2014 Dollars**	
HDD Level	**Cumulative Probability Of Occurrence (p)**	**Probability Of Exceeding (1-p)**	**Frequency of Occurrence 1/(1-p) (years)**	**Days Of Interruption**	**Cost of 25% Interruption**	**Prob Wghted Cost**	**Required Incremental Capacity (MMBtu)**	**Required Incremental Winter Volume (MMBtu)**	**Short-Haul Supply Cost**	**Long-Haul Supply Cost**
5,700	0.6135	0.3865	2.59	2	$39,775,908	$15,373,217	3,105	169,562	$1,225,334	$2,647,191
5,800	0.7147	0.2853	3.51	4	$84,359,337	$24,063,698	6,593	369,909	$2,651,474	$5,668,238
5,900	0.8013	0.1987	5.03	6	$124,496,693	$24,741,705	10,081	572,806	$4,090,421	$8,701,395
6,000	0.8697	0.1303	7.67	8	$167,453,449	$21,818,385	13,576	779,847	$5,550,945	$11,757,988
6,100	0.9198	0.0802	12.47	10	$210,053,711	$16,842,765	17,074	994,472	$7,049,911	$14,852,306
6,200	0.9538	0.0462	21.64	12	$253,499,411	$11,716,249	20,575	1,216,416	$8,586,095	$17,983,652
6,300	0.9751	0.0249	40.15	15	$298,190,562	$7,427,530	24,082	1,442,838	$10,145,434	$21,139,519
6,400	0.9875	0.0125	79.79	17	$343,308,687	$4,302,809	27,598	1,674,937	$11,734,362	$24,327,672
6,500	0.9941	0.0059	170.04	19	$386,182,057	$2,271,060	31,114	1,914,749	$13,362,065	$27,552,609
6,600	0.9974	0.0026	389.03	21	$427,550,829	$1,099,027	34,635	2,158,146	$15,008,414	$30,797,711
6,700	0.9990	0.0010	956.20	23	$471,347,289	$492,939	38,169	2,411,296	$16,705,244	$34,096,512
6,800	0.9996	0.0004	2526.84	25	$516,725,238	$204,494	41,703	2,669,122	$18,425,559	$37,417,519
6,900	0.9999	0.0001	7183.42	27	$562,045,614	$78,242	45,237	2,933,365	$20,178,106	$40,769,005
					Days Of Interruption times Cost of Interruption/Day	Cost of Interruption times Prob. of Exceeding			(Incremental Vol times Supply+D2 Costs) + (Incr Capacity times Short-Haul+ D1 Costs)	(Incremental Vol times Supply Cost) + (Incr Capacity times Long-Haul Cost)

EDD Level	**Cost of 75% Interruption**	**Prob Wghted Cost**
5,700	$119,327,724	$46,119,652
5,800	$253,078,010	$72,191,095
5,900	$373,490,080	$74,225,115
6,000	$502,360,347	$65,455,155
6,100	$630,161,132	$50,528,294
6,200	$760,498,234	$35,148,747
6,300	$894,571,687	$22,282,591
6,400	$1,029,926,060	$12,908,427
6,500	$1,158,546,172	$6,813,181
6,600	$1,282,652,488	$3,297,080
6,700	$1,414,041,868	$1,478,816
6,800	$1,550,175,713	$613,483
6,900	$1,686,136,841	$234,726

Chart III-E-10

Probability-Weighted Damages Costs vs
Cost of Replacement Volumes
National Grid Rhode Island



National Grid Rhode Island
Comparison of Resources and Requirements
Base Design Year
(BBtu)

Base Design Heating Season (Nov-Mar)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	4459	4474	4568	4639	4737	4735	4745	4811	4897	4924
	Providence	21101	21174	21619	21956	22419	22410	22458	22771	23177	23305
	Warren	724	726	742	753	769	769	770	781	795	799
	Westerly	457	459	468	476	486	486	487	493	502	505
Fuel Reimbursement		562	603	624	531	539	581	581	585	593	592
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	125	0	0	0	0	0	0	0	0	0
TOTAL		27,428	27,437	28,021	28,355	28,950	28,980	29,042	29,442	29,964	30,125
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	77	74	116	159	163	162	162	162	163	162
	Zone 4	5514	6069	5396	5145	5405	5213	5199	5270	5395	5372
	Dracut	760	711	773	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	3284	3064	3157	3176	3256	3338	3364
	Storage	1170	1036	1308	1280	1254	1299	1324	1313	1279	1302
TET/AGT	M2	5799	7175	7165	4328	4330	5604	5604	5610	5674	5629
	TCO	4973	4921	4996	4200	4637	4538	4548	4609	4694	4702
	Transco	189	188	188	170	154	188	188	188	189	188
	HubLine	590	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1353	346	322	534	358	361	379	398	412
	AIM (Millennium)	0	0	1366	1367	1105	1367	1367	1367	1376	1367
	M3	4454	1956	2031	4497	4816	3375	3381	3436	3495	3533
	AGT Citygate	168	0	0	0	0	0	0	0	0	0
	Storage	2407	2505	2670	2622	2421	2603	2604	2605	2611	2606
Liquid	GDF Suez	125	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		552	554	554	827	827	827	827	827	827	744
Unserved	Valley	16	27	32	0	32	52	60	101	128	134
	Providence	224	713	925	0	51	84	87	164	242	454
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	1	0	0	0	0	0	0	0	0	0
		241	740	957	0	82	136	147	266	369	589
TOTAL		27,428	27,437	28,021	28,355	28,950	28,980	29,042	29,442	29,964	30,125

National Grid Rhode Island
Comparison of Resources and Requirements
Base Design Year
(BBtu)

Base Design Non-Heating Season (Apr-Oct)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	1923	1970	2008	2037	2053	2063	2096	2117	2149	2149
	Providence	9099	9323	9501	9639	9718	9763	9919	10018	10169	10169
	Warren	312	320	326	331	333	335	340	344	349	349
	Westerly	197	202	206	209	211	212	215	217	220	220
Fuel Reimbursement		380	331	278	322	346	348	352	355	358	385
Underground Storage Refill		3712	3887	4177	3944	3837	3946	3976	3969	3944	3963
LNG Refill	Liquefaction	0	0	0	728	719	719	719	719	717	888
	Liquid	571	699	699	244	252	253	253	253	255	0
TOTAL		16,195	16,732	17,194	17,452	17,470	17,638	17,870	17,991	18,160	18,123
RESOURCES											
TGP	Dawn	0	0	0	0	0	0	0	0	0	0
	Niagara	12	9	134	202	230	230	230	230	230	230
	Zone 4	3137	3105	3315	3576	3324	3380	3450	3470	3481	3678
	Dracut	0	3	5	0	0	0	0	0	0	0
	TGP Citygate	0	0	0	0	0	0	0	0	0	0
	NED	0	0	0	0	0	0	0	0	0	0
	Storage	22	26	29	32	34	34	38	40	44	44
TET/AGT	M2	7688	6451	3842	3878	4761	4838	4870	4892	4929	4924
	TCO	454	391	409	428	604	614	644	662	688	711
	Transco	99	144	37	52	75	76	78	81	83	83
	HubLine	2	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1164	262	995	1030	1031	1036	1039	1044	1047
	AIM (Millennium)	0	0	1547	1112	1113	1113	1113	1113	1113	1113
	M3	3869	4277	6601	6779	5775	5915	6003	6055	6137	6137
	AGT Citygate	0	0	0	0	0	0	0	0	0	0
	Storage	194	319	169	10	128	10	11	11	11	11
Liquid	GDF Suez	508	508	508	244	252	253	253	253	255	0
	Gaz Met	63	191	191	0	0	0	0	0	0	0
LNG From Storage		145	145	145	145	145	145	145	145	145	145
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	0	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
TOTAL		16,195	16,732	17,194	17,452	17,470	17,638	17,870	17,991	18,160	18,123

National Grid Rhode Island
Comparison of Resources and Requirements
Base Design Year
(BBtu)

Base Design Annual

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	6381	6444	6576	6676	6791	6798	6841	6928	7046	7073
	Providence	30200	30497	31120	31595	32137	32173	32377	32789	33345	33474
	Warren	1036	1046	1067	1084	1102	1104	1111	1125	1144	1148
	Westerly	654	661	674	685	696	697	702	710	722	725
Fuel Reimbursement		943	935	902	853	885	929	934	940	950	977
Underground Storage Refill		3712	3887	4177	3944	3837	3946	3976	3969	3944	3963
LNG Refill	Liquefaction	0	0	0	728	719	719	719	719	717	888
	Liquid	696	699	699	244	252	253	253	253	255	0
TOTAL		43,623	44,169	45,215	45,808	46,420	46,618	46,912	47,433	48,124	48,249
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	157	156
	Niagara	89	83	250	361	393	392	392	392	393	392
	Zone 4	8651	9174	8711	8721	8729	8593	8649	8740	8876	9050
	Dracut	760	714	778	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	3284	3064	3157	3176	3256	3338	3364
	Storage	1193	1063	1337	1312	1288	1333	1362	1353	1322	1346
TET/AGT	M2	13486	13626	11007	8206	9091	10442	10474	10502	10604	10553
	TCO	5427	5312	5405	4628	5241	5152	5191	5271	5382	5413
	Transco	289	332	225	222	229	264	266	269	273	271
	HubLine	592	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	2516	608	1316	1563	1389	1397	1419	1441	1459
	AIM (Millennium)	0	0	2913	2480	2217	2479	2479	2479	2489	2480
	M3	8324	6233	8632	11276	10592	9290	9384	9490	9633	9671
	AGT Citygate	168	0	0	0	0	0	0	0	0	0
	Storage	2601	2824	2840	2632	2549	2613	2615	2616	2622	2617
Liquid	GDF Suez	633	508	508	244	252	253	253	253	255	0
	Gaz Met	63	191	191	0	0	0	0	0	0	0
LNG From Storage		696	698	698	972	972	972	972	972	972	888
Unserved	Valley	16	27	32	0	32	52	60	101	128	134
	Providence	224	713	925	0	51	84	87	164	242	454
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	1	0	0	0	0	0	0	0	0	0
		241	740	957	0	82	136	147	266	369	589
TOTAL		43,623	44,169	45,215	45,808	46,420	46,618	46,912	47,433	48,124	48,249

National Grid Rhode Island
Comparison of Resources and Requirements
Base Design Year
(BBtu)

Base Design Day

		Jan 2016	Jan 2017	Jan 2018	Jan 2019	Jan 2020	Jan 2021	Jan 2022	Jan 2023	Jan 2024	Jan 2025
REQUIREMENTS											
Firm Sendout	Valley	56	57	58	59	60	60	60	61	62	63
	Providence	267	270	275	280	284	286	286	290	293	298
	Warren	9	9	9	10	10	10	10	10	10	10
	Westerly	6	6	6	6	6	6	6	6	6	6
Fuel Reimbursement		5	5	5	5	5	5	5	5	5	5
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	0	0	0	0	0	0	0	0	0	0
TOTAL		343	346	354	361	365	368	368	373	377	383
RESOURCES											
TGP	Dawn	1	1	1	1	1	1	1	1	1	1
	Niagara	1	1	1	1	1	1	1	1	1	1
	Zone 4	41	41	41	41	41	41	41	41	41	41
	Dracut	15	15	15	0	0	0	0	0	0	0
	TGP Citygate	8	0	0	0	0	0	0	0	0	0
	NED	0	0	0	35	35	35	35	35	35	35
	Storage	11	11	11	11	11	11	11	11	11	11
TET/AGT	M2	49	49	49	49	49	49	49	49	49	49
	TCO	48	48	48	48	48	48	48	48	48	48
	Transco	1	1	1	1	1	1	1	1	1	1
	HubLine	15	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	17	9	9	9	9	9	9	9	9
	AIM (Millennium)	0	0	9	9	9	9	9	9	9	9
	M3	26	24	10	11	10	10	10	10	11	12
	AGT Citygate	5	0	0	0	0	0	0	0	0	0
	Storage	14	14	28	28	28	28	28	28	28	27
Liquid	GDF Suez	0	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		107	123	130	117	121	124	123	128	132	138
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	0	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
TOTAL		343	346	354	361	365	368	368	373	377	383

National Grid Rhode Island
Comparison of Resources and Requirements
Base Normal Year
(BBtu)

Base Normal Heating Season (Nov-Mar)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	4046	4060	4145	4209	4297	4296	4305	4364	4442	4467
	Providence	19332	19398	19804	20111	20534	20525	20569	20855	21225	21342
	Warren	663	665	679	690	704	704	706	715	728	732
	Westerly	420	421	430	436	446	445	446	453	461	463
Fuel Reimbursement		536	582	601	493	506	547	548	553	561	563
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	0	0	0	0	0	0	0	0	0	0
TOTAL		24,997	25,126	25,658	25,940	26,487	26,517	26,573	26,940	27,416	27,566
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	51	48	109	158	163	162	162	162	163	162
	Zone 4	5244	5871	5070	4865	5122	4775	4768	4854	4988	4982
	Dracut	509	414	482	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	2920	2361	2636	2652	2733	2836	2867
	Storage	1114	996	1306	1266	1206	1307	1323	1307	1269	1286
TET/AGT	M2	5796	7175	7151	4299	4296	5481	5490	5520	5594	5573
	TCO	4434	4504	4499	3303	4088	4043	4053	4101	4172	4188
	Transco	189	188	188	167	154	188	188	188	189	188
	HubLine	189	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1056	247	111	260	123	124	142	216	260
	AIM (Millennium)	0	0	1365	1367	1105	1366	1366	1366	1375	1366
	M3	4166	1614	1693	3976	4376	2858	2864	2983	3023	3192
	AGT Citygate	121	0	0	0	0	0	0	0	0	0
	Storage	2412	2505	2670	2668	2421	2602	2602	2602	2608	2603
Liquid	GDF Suez	0	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		363	554	554	684	778	821	827	827	827	744
Unserved	Valley	0	0	1	0	0	0	0	0	0	0
	Providence	0	46	169	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	46	170	0	0	0	0	0	0	0
TOTAL		24,997	25,126	25,658	25,940	26,487	26,517	26,573	26,940	27,416	27,566

National Grid Rhode Island
Comparison of Resources and Requirements
Base Normal Year
(BBtu)

Base Normal Non-Heating Season (Apr-Oct)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	1740	1782	1817	1843	1858	1866	1896	1915	1944	1944
	Providence	8312	8517	8680	8805	8878	8919	9061	9152	9289	9289
	Warren	285	292	298	302	305	306	311	314	319	319
	Westerly	180	185	188	191	193	194	197	199	202	202
Fuel Reimbursement		359	314	260	304	319	329	332	334	337	364
Underground Storage Refill		3640	3840	4157	3957	3770	3932	3950	3935	3906	3918
LNG Refill	Liquefaction	0	0	0	700	679	722	722	722	721	888
	Liquid	508	699	699	129	244	244	249	250	251	0
TOTAL		15,023	15,629	16,098	16,231	16,244	16,512	16,719	16,822	16,968	16,924
RESOURCES											
TGP	Dawn	0	0	0	0	0	0	0	0	0	0
	Niagara	6	5	127	194	230	230	230	230	230	230
	Zone 4	2789	2789	3031	3273	2974	3138	3193	3201	3200	3386
	Dracut	0	0	0	0	0	0	0	0	0	0
	TGP Citygate	0	0	0	0	0	0	0	0	0	0
	NED	0	0	0	0	0	0	0	0	0	0
	Storage	10	12	13	14	16	16	18	19	21	21
TET/AGT	M2	7464	6310	3690	3764	4591	4665	4696	4718	4755	4750
	TCO	339	306	318	327	449	453	472	483	500	524
	Transco	87	139	35	52	72	73	73	74	75	75
	HubLine	1	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1114	249	947	1004	1005	1009	1012	1016	1017
	AIM (Millennium)	0	0	1530	1112	1112	1112	1112	1112	1112	1112
	M3	3490	3785	6094	6267	5282	5423	5514	5570	5657	5657
	AGT Citygate	0	0	0	0	0	0	0	0	0	0
	Storage	185	328	168	8	127	8	8	8	8	8
Liquid	GDF Suez	508	508	508	129	244	244	249	250	251	0
	Gaz Met	0	191	191	0	0	0	0	0	0	0
LNG From Storage		145	145	145	145	145	145	145	145	145	145
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	0	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
TOTAL		15,023	15,629	16,098	16,231	16,244	16,512	16,719	16,822	16,968	16,924

National Grid Rhode Island
Comparison of Resources and Requirements
Base Normal Year
(BBtu)

Base Normal Annual

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	5785	5842	5961	6052	6155	6162	6201	6280	6386	6411
	Providence	27644	27915	28483	28917	29412	29444	29630	30007	30514	30632
	Warren	948	958	977	992	1009	1010	1016	1029	1047	1051
	Westerly	600	606	618	628	638	639	643	651	662	665
Fuel Reimbursement		895	896	862	798	825	876	880	887	898	927
Underground Storage Refill		3640	3840	4157	3957	3770	3932	3950	3935	3906	3918
LNG Refill	Liquefaction	0	0	0	700	679	722	722	722	721	888
	Liquid	508	699	699	129	244	244	249	250	251	0
TOTAL		40,020	40,755	41,757	42,171	42,731	43,029	43,292	43,761	44,384	44,490
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	58	53	236	351	393	392	392	392	393	392
	Zone 4	8033	8660	8101	8138	8096	7913	7962	8055	8187	8367
	Dracut	509	414	482	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	2920	2361	2636	2652	2733	2836	2867
	Storage	1124	1007	1319	1280	1222	1323	1341	1326	1290	1307
TET/AGT	M2	13260	13485	10841	8063	8886	10146	10185	10238	10348	10323
	TCO	4773	4809	4817	3630	4537	4496	4524	4584	4672	4711
	Transco	276	327	222	219	226	261	261	262	264	263
	HubLine	190	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	2169	496	1059	1264	1127	1133	1153	1232	1277
	AIM (Millennium)	0	0	2895	2479	2217	2478	2478	2478	2488	2479
	M3	7655	5399	7788	10243	9658	8282	8378	8553	8681	8850
	AGT Citygate	121	0	0	0	0	0	0	0	0	0
	Storage	2597	2833	2838	2676	2548	2610	2610	2610	2616	2611
Liquid	GDF Suez	508	508	508	129	244	244	249	250	251	0
	Gaz Met	0	191	191	0	0	0	0	0	0	0
LNG From Storage		508	699	699	829	923	966	971	972	972	888
Unserved	Valley	0	0	1	0	0	0	0	0	0	0
	Providence	0	46	169	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	46	170	0	0	0	0	0	0	0
TOTAL		40,020	40,755	41,757	42,171	42,731	43,029	43,292	43,761	44,384	44,490

National Grid Rhode Island
Comparison of Resources and Requirements
High Design Year
(BBtu)

High Design Heating Season (Nov-Mar)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	4452	4464	4598	4695	4795	4769	4753	4812	4909	4947
	Providence	21069	21128	21759	22217	22694	22571	22492	22771	23233	23413
	Warren	723	725	746	762	778	774	771	781	797	803
	Westerly	456	458	471	481	492	489	487	493	503	507
Fuel Reimbursement		561	603	626	537	543	583	582	585	593	593
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	125	0	0	0	0	0	0	0	0	0
TOTAL		27,386	27,378	28,200	28,692	29,302	29,187	29,085	29,443	30,036	30,264
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	77	73	116	162	163	162	162	162	163	162
	Zone 4	5509	6066	5415	5188	5439	5226	5204	5270	5404	5398
	Dracut	756	705	791	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	3333	3152	3200	3184	3256	3350	3387
	Storage	1169	1033	1308	1272	1261	1314	1324	1313	1279	1295
TET/AGT	M2	5799	7175	7165	4329	4334	5606	5605	5610	5675	5630
	TCO	4966	4911	5029	4309	4689	4569	4554	4609	4703	4717
	Transco	189	188	188	170	154	188	188	188	189	188
	HubLine	587	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1343	353	342	562	368	363	379	402	418
	AIM (Millennium)	0	0	1366	1367	1105	1367	1367	1367	1376	1367
	M3	4448	1946	2052	4497	4817	3400	3386	3436	3506	3555
	AGT Citygate	168	0	0	0	0	0	0	0	0	0
	Storage	2407	2505	2670	2669	2447	2604	2604	2605	2611	2607
Liquid	GDF Suez	125	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		552	554	554	827	827	827	827	827	827	744
Unserved	Valley	16	27	45	17	57	75	50	115	28	161
	Providence	210	696	991	56	138	126	112	151	366	480
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	1	0	0	0	0	0	0	0	0	0
		227	723	1,037	73	195	201	161	266	393	641
TOTAL		27,386	27,378	28,200	28,692	29,302	29,187	29,085	29,443	30,036	30,264

National Grid Rhode Island
Comparison of Resources and Requirements
High Design Year
(BBtu)

High Design Non-Heating Season (Apr-Oct)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	1913	1980	2031	2061	2068	2065	2095	2123	2162	2162
	Providence	9053	9371	9611	9755	9787	9773	9916	10050	10233	10233
	Warren	311	321	330	335	336	335	340	345	351	351
	Westerly	196	203	208	211	212	212	215	218	222	222
Fuel Reimbursement		379	332	280	325	348	349	352	355	359	387
Underground Storage Refill		3711	3885	4180	3985	3871	3963	3976	3970	3946	3959
LNG Refill	Liquefaction	0	0	0	728	719	719	719	718	716	888
	Liquid	571	699	699	244	253	253	253	254	255	0
TOTAL		16,133	16,792	17,339	17,645	17,594	17,668	17,866	18,032	18,244	18,201
RESOURCES											
TGP	Dawn	0	0	0	0	0	0	0	0	0	0
	Niagara	12	9	135	203	230	230	230	230	230	230
	Zone 4	3120	3117	3353	3602	3350	3399	3450	3479	3500	3691
	Dracut	0	4	7	0	0	0	0	0	0	0
	TGP Citygate	0	0	0	0	0	0	0	0	0	0
	NED	0	0	0	0	0	0	0	0	0	0
	Storage	22	28	32	34	35	35	38	41	45	45
TET/AGT	M2	7665	6453	3859	3946	4800	4840	4868	4899	4945	4940
	TCO	451	401	423	448	617	616	643	668	699	722
	Transco	99	144	38	52	76	76	78	82	84	84
	HubLine	2	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1166	264	1000	1032	1031	1036	1040	1046	1049
	AIM (Millennium)	0	0	1549	1113	1113	1113	1113	1113	1113	1113
	M3	3851	4308	6667	6848	5815	5921	6002	6071	6171	6171
	AGT Citygate	0	0	0	0	0	0	0	0	0	0
	Storage	194	319	169	10	128	10	11	11	11	12
Liquid	GDF Suez	508	508	508	244	253	253	253	254	255	0
	Gaz Met	63	191	191	0	0	0	0	0	0	0
LNG From Storage		145	145	145	145	145	145	145	145	145	145
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	0	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
TOTAL		16,133	16,792	17,339	17,645	17,594	17,668	17,866	18,032	18,244	18,201

National Grid Rhode Island
Comparison of Resources and Requirements
High Design Year
(BBtu)

High Design Annual

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	6365	6445	6629	6756	6863	6834	6848	6935	7071	7109
	Providence	30121	30499	31371	31973	32480	32344	32407	32821	33465	33646
	Warren	1033	1046	1076	1097	1114	1109	1112	1126	1148	1154
	Westerly	653	661	680	693	704	701	702	711	725	729
Fuel Reimbursement		940	935	906	862	891	931	934	941	953	980
Underground Storage Refill		3711	3885	4180	3985	3871	3963	3976	3970	3946	3959
LNG Refill	Liquefaction	0	0	0	728	719	719	719	718	716	888
	Liquid	696	699	699	244	253	253	253	254	255	0
TOTAL		43,519	44,169	45,539	46,337	46,896	46,854	46,951	47,475	48,280	48,465
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	157	156
	Niagara	89	83	251	365	393	392	392	392	393	392
	Zone 4	8630	9184	8768	8790	8789	8624	8654	8749	8905	9089
	Dracut	756	708	798	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	3333	3152	3200	3184	3256	3350	3388
	Storage	1191	1061	1340	1306	1296	1349	1362	1354	1323	1340
TET/AGT	M2	13464	13628	11024	8274	9134	10446	10473	10508	10620	10570
	TCO	5416	5312	5452	4757	5306	5185	5198	5277	5403	5439
	Transco	288	332	226	222	230	264	266	270	273	271
	HubLine	589	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	2510	617	1342	1595	1399	1399	1420	1448	1467
	AIM (Millennium)	0	0	2916	2480	2217	2479	2479	2479	2489	2480
	M3	8299	6254	8719	11344	10632	9321	9388	9507	9678	9726
	AGT Citygate	168	0	0	0	0	0	0	0	0	0
	Storage	2601	2824	2840	2679	2575	2614	2615	2616	2622	2619
Liquid	GDF Suez	633	508	508	244	253	253	253	254	255	0
	Gaz Met	63	191	191	0	0	0	0	0	0	0
LNG From Storage		697	698	698	972	972	972	972	972	972	888
Unserved	Valley	16	27	45	17	57	75	50	115	28	161
	Providence	210	696	991	56	138	126	112	151	366	480
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	1	0	0	0	0	0	0	0	0	0
		227	723	1,037	73	195	201	161	266	393	641
TOTAL		43,519	44,169	45,539	46,337	46,896	46,854	46,951	47,475	48,280	48,465

National Grid Rhode Island
Comparison of Resources and Requirements
High Design Year
(BBtu)

High Design Day

		Jan 2016	Jan 2017	Jan 2018	Jan 2019	Jan 2020	Jan 2021	Jan 2022	Jan 2023	Jan 2024	Jan 2025
REQUIREMENTS											
Firm Sendout	Valley	56	57	59	60	61	61	61	61	62	63
	Providence	266	269	277	284	288	288	287	290	294	299
	Warren	9	9	10	10	10	10	10	10	10	10
	Westerly	6	6	6	6	6	6	6	6	6	6
Fuel Reimbursement		5	5	5	5	5	5	5	5	5	5
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	0	0	0	0	0	0	0	0	0	0
TOTAL		342	346	357	366	370	371	369	373	377	384
RESOURCES											
TGP	Dawn	1	1	1	1	1	1	1	1	1	1
	Niagara	1	1	1	1	1	1	1	1	1	1
	Zone 4	41	41	41	41	41	41	41	41	41	41
	Dracut	15	15	15	0	0	0	0	0	0	0
	TGP Citygate	8	0	0	0	0	0	0	0	0	0
	NED	0	0	0	35	35	35	35	35	35	35
	Storage	11	11	11	11	11	11	11	11	11	11
TET/AGT	M2	49	49	49	49	49	49	49	49	49	49
	TCO	48	48	48	48	48	48	48	48	48	48
	Transco	1	1	1	1	1	1	1	1	1	1
	HubLine	15	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	17	9	9	9	9	9	9	9	9
	AIM (Millennium)	0	0	9	9	9	9	9	9	9	9
	M3	26	24	10	10	10	10	10	10	11	12
	AGT Citygate	5	0	0	0	0	0	0	0	0	0
	Storage	14	14	28	28	28	28	28	28	28	27
Liquid	GDF Suez	0	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		107	123	132	121	126	126	124	128	133	139
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	1	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	1	0	0	0	0	0	0	0
TOTAL		342	346	357	366	370	371	369	373	377	384

National Grid Rhode Island
Comparison of Resources and Requirements
High Normal Year
(BBtu)

High Normal Heating Season (Nov-Mar)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	4040	4050	4171	4258	4349	4326	4311	4364	4453	4487
	Providence	19302	19354	19929	20347	20782	20671	20599	20854	21276	21441
	Warren	662	664	684	698	713	709	707	715	730	735
	Westerly	419	420	433	442	451	449	447	453	462	465
Fuel Reimbursement		535	582	603	497	509	549	548	553	562	565
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	0	0	0	0	0	0	0	0	0	0
TOTAL		24,957	25,069	25,819	26,242	26,805	26,704	26,612	26,939	27,481	27,693
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	51	47	110	158	163	162	162	162	163	162
	Zone 4	5239	5888	5093	4894	5164	4812	4775	4848	4994	5004
	Dracut	504	408	506	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	2961	2464	2677	2661	2733	2850	2896
	Storage	1113	972	1306	1278	1212	1304	1323	1312	1273	1286
TET/AGT	M2	5796	7175	7152	4302	4298	5499	5493	5520	5599	5578
	TCO	4423	4490	4537	3409	4139	4068	4058	4101	4181	4221
	Transco	189	188	188	167	154	188	188	188	189	188
	HubLine	181	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1049	253	117	268	126	125	142	236	282
	AIM (Millennium)	0	0	1365	1367	1105	1366	1366	1366	1375	1366
	M3	4160	1603	1717	4000	4434	2919	2878	2983	3029	3208
	AGT Citygate	117	0	0	0	0	0	0	0	0	0
	Storage	2412	2505	2667	2667	2421	2602	2602	2602	2608	2603
Liquid	GDF Suez	0	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		363	554	554	768	827	827	827	827	827	744
Unserved	Valley	0	0	2	0	0	0	0	0	0	0
	Providence	0	36	215	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	36	216	0	0	0	0	0	0	0
TOTAL		24,957	25,069	25,819	26,242	26,805	26,704	26,612	26,939	27,481	27,693

National Grid Rhode Island
Comparison of Resources and Requirements
High Normal Year
(BBtu)

High Normal Non-Heating Season (Apr-Oct)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	1731	1792	1838	1865	1871	1868	1896	1921	1956	1956
	Providence	8270	8561	8780	8912	8941	8928	9058	9181	9348	9348
	Warren	284	294	301	306	307	306	311	315	321	321
	Westerly	179	186	191	193	194	194	197	199	203	203
Fuel Reimbursement		357	314	262	307	327	329	332	335	338	365
Underground Storage Refill		3638	3816	4156	3968	3776	3930	3950	3941	3911	3919
LNG Refill	Liquefaction	0	0	0	700	724	724	722	722	721	888
	Liquid	508	699	699	213	248	248	249	250	251	0
TOTAL		14,968	15,661	16,226	16,464	16,388	16,526	16,715	16,864	17,049	17,000
RESOURCES											
TGP	Dawn	0	0	0	0	0	0	0	0	0	0
	Niagara	6	5	128	195	230	230	230	230	230	230
	Zone 4	2777	2781	3064	3319	3049	3139	3192	3214	3219	3400
	Dracut	0	0	0	0	0	0	0	0	0	0
	TGP Citygate	0	0	0	0	0	0	0	0	0	0
	NED	0	0	0	0	0	0	0	0	0	0
	Storage	10	12	15	16	17	16	18	19	22	22
TET/AGT	M2	7440	6313	3703	3780	4603	4666	4694	4724	4769	4764
	TCO	338	310	326	336	457	454	471	486	507	531
	Transco	86	139	35	52	73	73	73	74	76	76
	HubLine	1	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1118	250	951	1006	1005	1009	1012	1018	1019
	AIM (Millennium)	0	0	1532	1112	1112	1112	1112	1112	1112	1112
	M3	3472	3812	6162	6338	5323	5430	5514	5589	5693	5693
	AGT Citygate	0	0	0	0	0	0	0	0	0	0
	Storage	185	327	168	8	127	8	8	8	8	8
Liquid	GDF Suez	508	508	508	213	248	248	249	250	251	0
	Gaz Met	0	191	191	0	0	0	0	0	0	0
LNG From Storage		145	145	145	145	145	145	145	145	145	145
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	0	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
TOTAL		14,968	15,661	16,226	16,464	16,388	16,526	16,715	16,864	17,049	17,000

National Grid Rhode Island
Comparison of Resources and Requirements
High Normal Year
(BBtu)

		High Normal Annual									
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	5770	5842	6008	6123	6220	6194	6207	6286	6409	6444
	Providence	27572	27915	28710	29259	29723	29599	29657	30035	30624	30789
	Warren	946	958	985	1004	1020	1015	1017	1030	1050	1056
	Westerly	598	606	623	635	645	642	644	652	665	668
Fuel Reimbursement		892	895	865	804	837	879	880	888	900	930
Underground Storage Refill		3638	3816	4156	3968	3776	3930	3950	3941	3911	3919
LNG Refill	Liquefaction	0	0	0	700	724	724	722	722	721	888
	Liquid	508	699	699	213	248	248	249	250	251	0
TOTAL		39,925	40,731	42,045	42,706	43,192	43,231	43,327	43,803	44,530	44,693
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	57	52	238	353	393	392	392	392	393	392
	Zone 4	8016	8669	8158	8213	8213	7951	7968	8062	8213	8404
	Dracut	504	408	506	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	2961	2464	2677	2661	2733	2850	2896
	Storage	1123	984	1320	1294	1228	1320	1341	1331	1295	1307
TET/AGT	M2	13236	13488	10855	8082	8901	10165	10187	10244	10369	10343
	TCO	4762	4800	4863	3745	4596	4522	4529	4587	4688	4752
	Transco	275	327	223	219	227	261	261	262	265	263
	HubLine	182	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	2167	503	1068	1274	1131	1134	1154	1253	1301
	AIM (Millennium)	0	0	2897	2479	2217	2478	2478	2479	2488	2479
	M3	7633	5416	7879	10338	9757	8349	8391	8572	8722	8901
	AGT Citygate	117	0	0	0	0	0	0	0	0	0
	Storage	2597	2832	2835	2675	2548	2610	2610	2610	2616	2611
Liquid	GDF Suez	508	508	508	213	248	248	249	250	251	0
	Gaz Met	0	191	191	0	0	0	0	0	0	0
LNG From Storage		508	698	698	913	972	972	972	972	972	888
Unserved	Valley	0	0	2	0	0	0	0	0	0	0
	Providence	0	36	215	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	36	216	0	0	0	0	0	0	0
TOTAL		39,925	40,731	42,045	42,706	43,192	43,231	43,327	43,803	44,530	44,693

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap Year
(BBtu)

Cold Snap Heating Season (Nov-Mar)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	4248	4264	4353	4421	4512	4511	4521	4583	4663	4691
	Providence	20297	20372	20798	21123	21558	21557	21600	21899	22280	22414
	Warren	696	699	713	725	739	739	741	751	764	769
	Westerly	440	442	451	458	468	468	469	475	484	486
Fuel Reimbursement		540	586	605	508	518	559	560	564	572	572
Underground Storage Refill		0	0	0	0	0	0	0	0	0	0
LNG Refill	Liquefaction	0	0	0	0	0	0	0	0	0	0
	Liquid	125	0	0	0	0	0	0	0	0	0
TOTAL		26,346	26,362	26,920	27,235	27,795	27,834	27,890	28,273	28,762	28,932
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	59	54	109	158	163	162	162	162	163	162
	Zone 4	5273	5908	5098	4881	5163	4932	4927	4981	5102	5102
	Dracut	618	533	591	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	2920	2485	2636	2652	2733	2836	2868
	Storage	1114	987	1307	1279	1207	1294	1309	1305	1269	1264
TET/AGT	M2	5796	7175	7153	4307	4320	5494	5503	5531	5604	5577
	TCO	4474	4543	4548	3646	4255	4231	4241	4296	4380	4396
	Transco	189	188	188	167	154	188	188	188	189	188
	HubLine	402	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1126	306	267	425	292	294	316	332	350
	AIM (Millennium)	0	0	1365	1367	1105	1366	1366	1366	1375	1366
	M3	4241	1704	1772	4244	4674	3173	3181	3236	3280	3313
	AGT Citygate	168	0	0	0	0	0	0	0	0	0
	Storage	2412	2505	2670	2669	2431	2602	2602	2602	2608	2603
Liquid	GDF Suez	125	0	0	0	0	0	0	0	0	0
	Gaz Met	0	0	0	0	0	0	0	0	0	0
LNG From Storage		552	554	554	827	827	827	827	827	827	744
Unserved	Valley	54	64	80	0	0	0	0	0	0	0
	Providence	454	867	1024	349	431	482	483	576	640	843
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	7	0	0	0	0	0	0	0	0	0
		515	931	1,104	349	431	482	483	576	640	843
TOTAL		26,346	26,362	26,920	27,235	27,795	27,834	27,890	28,273	28,762	28,932

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap Year
(BBtu)

Cold Snap Non-Heating Season (Apr-Oct)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	1740	1782	1817	1843	1858	1866	1896	1915	1944	1944
	Providence	8312	8517	8680	8805	8878	8919	9061	9152	9289	9289
	Warren	285	292	298	302	305	306	311	314	319	319
	Westerly	180	185	188	191	193	194	197	199	202	202
Fuel Reimbursement		359	314	261	305	326	329	332	334	337	364
Underground Storage Refill		3639	3831	4159	3969	3780	3920	3937	3933	3906	3896
LNG Refill	Liquefaction	0	0	0	728	724	724	722	722	721	888
	Liquid	571	699	699	244	248	248	249	250	251	0
TOTAL		15,087	15,620	16,100	16,387	16,311	16,505	16,706	16,820	16,968	16,902
RESOURCES											
TGP	Dawn	0	0	0	0	0	0	0	0	0	0
	Niagara	6	5	127	194	230	230	230	230	230	230
	Zone 4	2788	2780	3033	3286	3027	3127	3180	3199	3200	3364
	Dracut	0	0	0	0	0	0	0	0	0	0
	TGP Citygate	0	0	0	0	0	0	0	0	0	0
	NED	0	0	0	0	0	0	0	0	0	0
	Storage	10	12	13	14	16	16	18	19	21	21
TET/AGT	M2	7464	6310	3690	3764	4600	4665	4696	4718	4755	4750
	TCO	339	306	318	327	449	453	472	483	500	524
	Transco	87	139	35	52	72	73	73	74	75	75
	HubLine	1	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	1114	249	964	1004	1005	1009	1012	1016	1017
	AIM (Millennium)	0	0	1530	1112	1112	1112	1112	1112	1112	1112
	M3	3490	3785	6094	6278	5282	5423	5514	5570	5657	5657
	AGT Citygate	0	0	0	0	0	0	0	0	0	0
	Storage	185	328	168	8	127	8	8	8	8	8
Liquid	GDF Suez	508	508	508	244	248	248	249	250	251	0
	Gaz Met	63	191	191	0	0	0	0	0	0	0
LNG From Storage		145	145	145	145	145	145	145	145	145	145
Unserved	Valley	0	0	0	0	0	0	0	0	0	0
	Providence	0	0	0	0	0	0	0	0	0	0
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
TOTAL		15,087	15,620	16,100	16,387	16,311	16,505	16,706	16,820	16,968	16,902

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap Year
(BBtu)

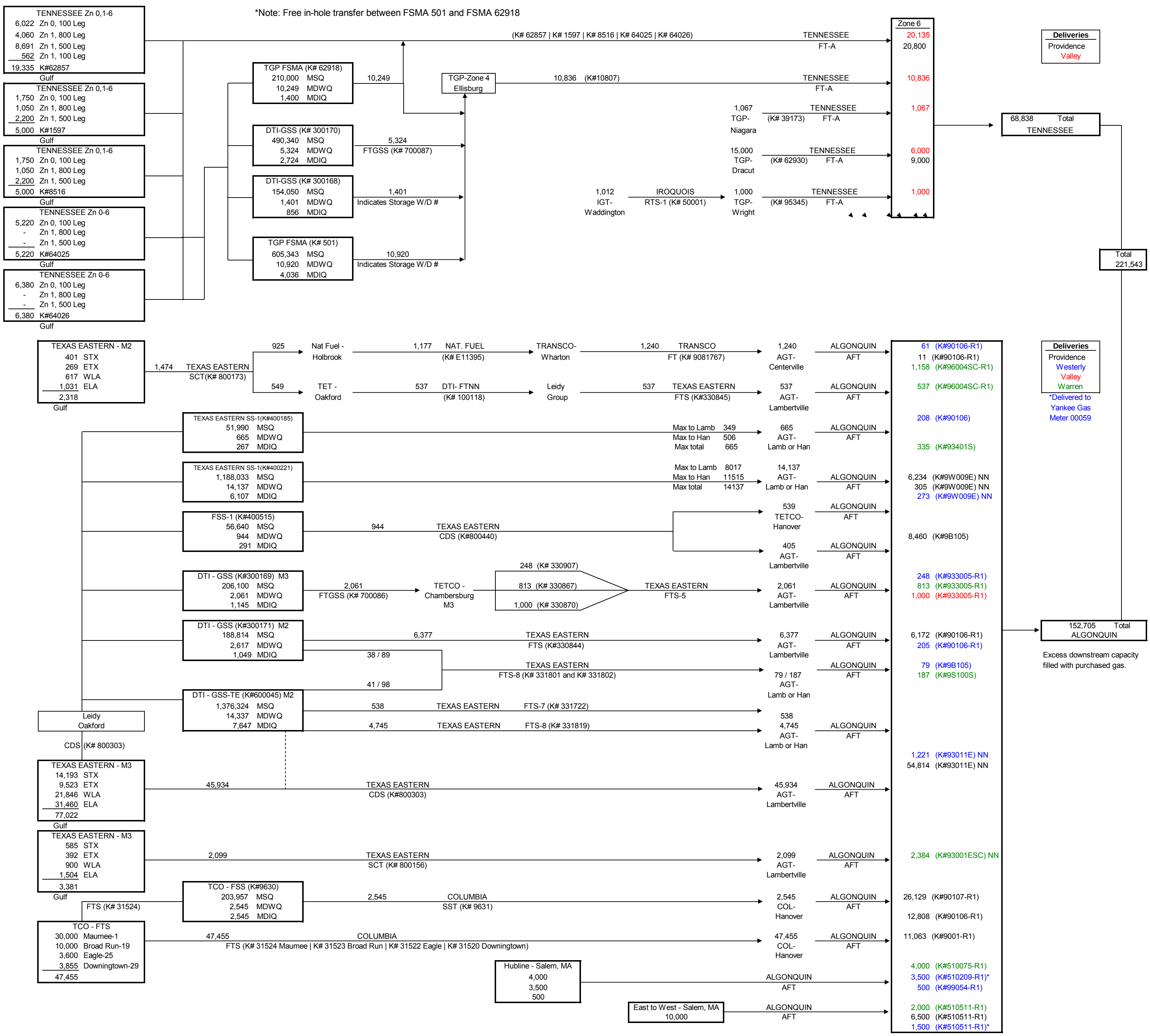
Cold Snap Annual

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
REQUIREMENTS											
Firm Sendout	Valley	5987	6046	6169	6263	6370	6378	6417	6499	6607	6635
	Providence	28609	28889	29477	29928	30436	30475	30661	31052	31569	31703
	Warren	981	991	1011	1027	1044	1045	1052	1065	1083	1087
	Westerly	621	627	640	650	661	661	665	674	685	688
Fuel Reimbursement		898	899	865	813	844	888	892	899	909	936
Underground Storage Refill		3639	3831	4159	3969	3780	3920	3937	3933	3906	3896
LNG Refill	Liquefaction	0	0	0	728	724	724	722	722	721	888
	Liquid	696	699	699	244	248	248	249	250	251	0
TOTAL		41,433	41,982	43,020	43,622	44,105	44,340	44,596	45,093	45,730	45,834
RESOURCES											
TGP	Dawn	156	155	155	155	156	155	155	155	156	155
	Niagara	65	59	236	351	393	392	392	392	393	392
	Zone 4	8061	8687	8131	8167	8190	8059	8106	8180	8301	8465
	Dracut	618	533	591	0	0	0	0	0	0	0
	TGP Citygate	252	0	0	0	0	0	0	0	0	0
	NED	0	0	0	2920	2485	2636	2652	2733	2836	2868
	Storage	1124	999	1320	1293	1222	1311	1327	1324	1290	1285
TET/AGT	M2	13260	13485	10843	8071	8920	10160	10199	10249	10359	10326
	TCO	4814	4849	4866	3973	4704	4684	4712	4779	4880	4920
	Transco	276	327	222	219	226	261	261	262	264	263
	HubLine	403	0	0	0	0	0	0	0	0	0
	AIM (Ramapo)	0	2240	555	1231	1429	1296	1303	1327	1347	1367
	AIM (Millennium)	0	0	2895	2479	2217	2478	2478	2478	2488	2479
	M3	7731	5489	7866	10522	9955	8597	8695	8806	8937	8971
	AGT Citygate	168	0	0	0	0	0	0	0	0	0
	Storage	2597	2833	2838	2676	2558	2610	2610	2610	2616	2611
Liquid	GDF Suez	633	508	508	244	248	248	249	250	251	0
	Gaz Met	63	191	191	0	0	0	0	0	0	0
LNG From Storage		696	699	699	972	972	972	972	972	972	888
Unserved	Valley	54	64	80	0	0	0	0	0	0	0
	Providence	454	867	1024	349	431	482	483	576	640	843
	Warren	0	0	0	0	0	0	0	0	0	0
	Westerly	7	0	0	0	0	0	0	0	0	0
		515	931	1,104	349	431	482	483	576	640	843
TOTAL		41,433	41,982	43,020	43,622	44,105	44,340	44,596	45,093	45,730	45,834

RHODE ISLAND COMPANIES - CONSOLIDATED PORTFOLIO SCHEMATIC

Peak Season Volumes

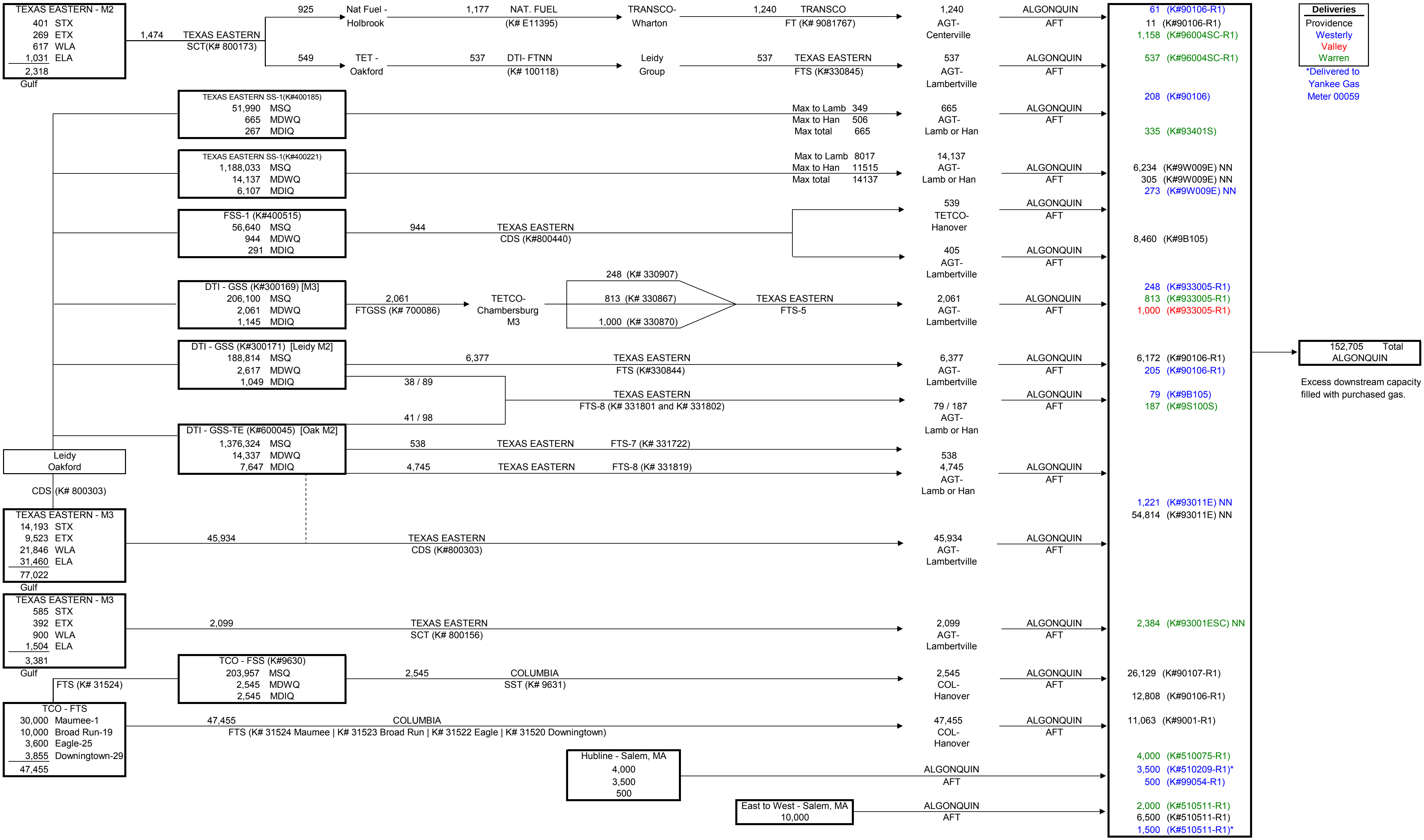
As of November 1, 2015



RHODE ISLAND COMPANIES - ALGONQUIN GAS TRANSMISSION
PORTFOLIO SCHEMATIC

Peak Season Volumes

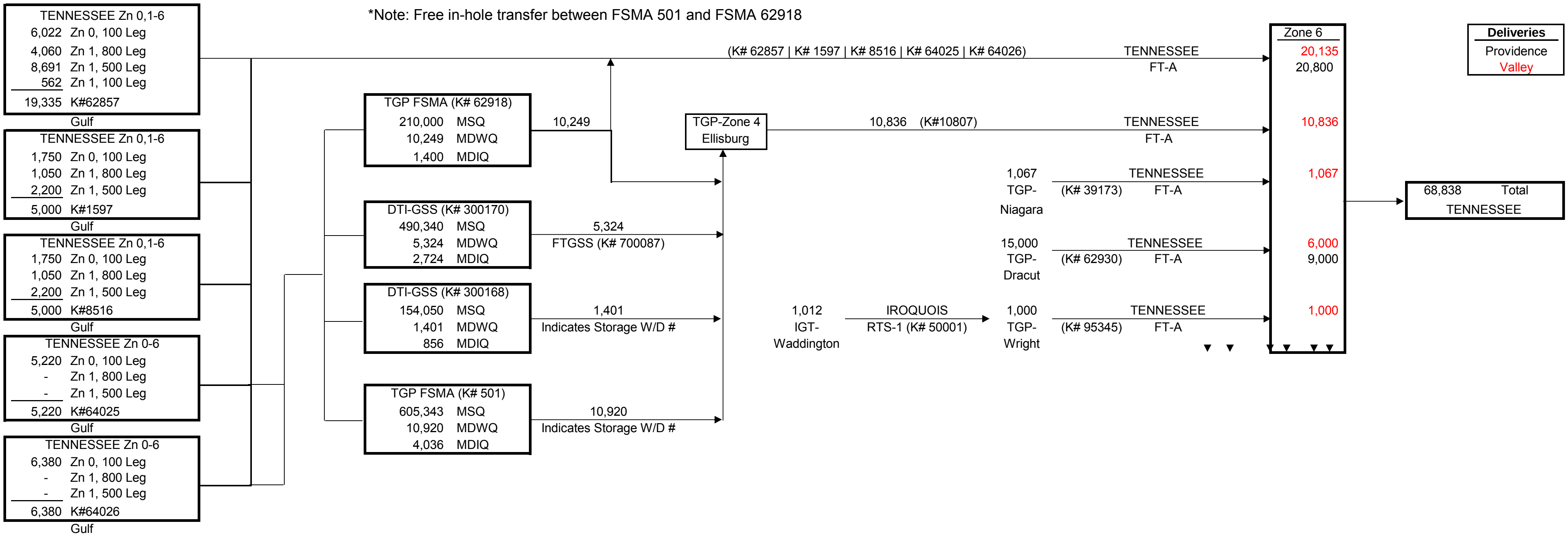
As of November 1, 2015



RHODE ISLAND COMPANIES - TENNESSEE GAS PIPELINE
PORTFOLIO SCHEMATIC

Peak Season Volumes

As of November 1, 2015



NATIONAL GRID - RHODE ISLAND ASSETS
Transportation Contracts

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
PG	Narragansett Electric	Algonquin	9001	AFT1FT3	11,063	4,037,995	12/14/2016	Yes	Part-284 transportation service (365-day) used to transport gas from the Columbia interconnect at Hanover, NJ (11,063 MMBtu) to National Grid - Dey St (11,063 MMBtu).
PG	Narragansett Electric	Algonquin	90106	AFT-14	19,465	7,104,725	10/31/2017	Yes	Part-284 transportation service (365-day) used to transport gas from the Columbia interconnect at Hanover, NJ (12,808 MMBtu), TETCO interconnect at Lamberville (6,585 MMBtu) and Transco interconnect at Centerville (72 MMBtu) to National Grid - Dey St (9,223 MMBtu), National Grid - Tiverton (598 MMBtu), National Grid - Westerly (474 MMBtu), National Grid - E. Providence (4,092 Mmbtu), and National Grid - Portsmouth (5,078 MMBtu).
PG	Narragansett Electric	Algonquin	90107	AFT-1W	26,129	3,945,479	10/31/2017	Yes	Part-284 service with a seasonally adjusted MDQ of (26,129 MMBtu), used to transport gas from the Columbia interconnect at Hanover, NJ to National Grid - Dey St (19, 514 MMBtu) and National Grid - E. Providence (6,615 MMBtu).
VG	Narragansett Electric	Algonquin	933005	AFT-1P	2,061	752,265	3/31/2017	Yes	Part-284 transportation service (365-day) used to transport gas from the TETCO interconnect at Lamberville, NJ (2,061 MMBtu) to National Grid - Cumberland (1,000 MMBtu), Narragansett Lectric - Westerly (248 MMBtu), and National Grid - Warren (813 MMBtu).
BW	Narragansett Electric	Algonquin	93001ESC	AFT-ES1	2,384	771,904	10/31/2017	Yes	Part-284 NO NOTICE service with a seasonally adjusted MDQ of (2,384 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ (1,377 MMBtu) and Hanover, NJ (1,007 MMBtu) to National Grid - Warren (2,384 MMBtu).
PG	Narragansett Electric	Algonquin	93011E	AFT-E1	56,035	19,446,885	10/31/2017	Yes	Part-284 NO NOTICE service with a seasonally adjusted MDQ of (56,035 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ (34,668 MMBtu) and Hanover, NJ (21,367 MMBtu) to National Grid - Dey St (25,137 MMBtu), National Grid - Westerly (1,221 MMBtu), National Grid - E. Providence (48,147 MMBtu), National Grid - Warren (4,173 MMBtu), National Grid - Portsmouth (6,504 MMBtu), and National Grid - Tiverton (163 MMBtu).
BW	Narragansett Electric	Algonquin	93401S	AFT-1S4	335	122,275	10/31/2017	Yes	Part-284 transportation service (365-day) used to transport gas from the TETCO interconnect at Lambertville, NJ (335 MMBtu) to National Grid - Warren (335 MMBtu).
BW	Narragansett Electric	Algonquin	96004SC	AFT-1S3	1,695	618,675	10/31/2017	Yes	Part-284 firm transportation service (365-day) used to transport gas from the TETCO interconnect at Lambertville, NJ (537 MMBtu) and Centerville, NJ (1,158 MMBtu) to National Grid - Warren (1,695 MMBtu).
PG	Narragansett Electric	Algonquin	9B105	AFT-1B	8,539	1,813,145	10/31/2017	Yes	Part-284 service with a seasonally adjusted MDQ of (8,539 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ to National Grid - Dey St (4,258 MMBtu), National Grid - Portsmouth (4,202 MMBtu) and National Grid - Westerly (79 MMBtu).

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
BW	Narragansett Electric	Algonquin	9S100S	AFT-1SX	187	39,737	10/31/2017	Yes	Part-284 service with a seasonally adjusted MDQ of (187 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ to National Grid - Warren (187 MMBtu).
PG	Narragansett Electric	Algonquin	9W009E	AFT-EW	6,812	1,446,384	10/31/2017	Yes	Part-284 NO NOTICE service with a seasonally adjusted MDQ of (6,812 MMBtu), used to transport gas from the TETCO interconnect at Hanover, NJ (4,222 MMBtu) and Lamberville, NJ (2,590 MMBtu) to National Grid - Dey St (6,234 MMBtu), National Grid - Westerly (273 MMBtu), and National Grid - Portsmouth (305 MMBtu).
PG	Narragansett Electric	Algonquin Hubline	99054	AFT1-H	500	182,500	11/30/2023	No	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (500 MMBtu) to National Grid - Westerly (500 MMBtu).
BW	Narragansett Electric	Algonquin Hubline	510075	AFT1-H	4,000	1,460,000	11/30/2016	Yes	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (4,000 MMBtu) to National Grid - Warren (4,000 MMBtu).
PG	Narragansett Electric	Algonquin Hubline	510209	AFT1-H	3,500	1,277,500	10/31/2017	Yes	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (3,500 MMBtu) to Montiville (3,500 MMBtu).
NEC	Narragansett Electric	Algonquin Hubline - East to West -	510511	AFT1-H	10,000	3,650,000	10/31/2020	No	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (10,000 MMBtu) to National Grid - Warren (2,000 MMBtu), National Grid - Portsmouth (6,000 MMBtu), National Grid - Tiverton (500 MMBtu) and Montiville (1,500 MMBtu).
PG	Narragansett Electric	Columbia	31520	FTS	3,855	1,407,075	10/31/2020	No	Part-284 transportation service used to transport gas from Downingtown-29 (3,855 MMBtu) to Columbia interconnect at Hanover, NJ (3,855 MMBtu).
PG	Narragansett Electric	Columbia	31522	FTS	3,600	1,314,000	10/31/2020	No	Part-284 transportation service used to transport gas from Eagle-25 (3,600 MMBtu) to Columbia interconnect at Hanover, NJ (3,600 MMBtu).
PG	Narragansett Electric	Columbia	31523	FTS	10,000	3,650,000	10/31/2020	No	Part-284 transportation service used to transport gas from Broad Run-19 (10,000 MMBtu) to Columbia interconnect at Hanover, NJ (10,000 MMBtu).
PG	Narragansett Electric	Columbia	31524	FTS	30,000	10,950,000	10/31/2020	No	Part-284 transportation service used to transport gas from Maumee-1 (30,000 MMBtu) to Columbia interconnect at Hanover, NJ (30,000 MMBtu).
PG	Narragansett Electric	Columbia	9631	SST	2,545	695,966	4/1/2040	No	Part-284 transportation service used to transport gas from RP Strorage Point TCO-FSS #9630 (2,545 MMBtu) to Columbia interconnect at Hanover, NJ (2,545 MMBtu). MDQ Seasonally adjusted to be 1,272 MDQ from Apr - Sep.
BW	Narragansett Electric	Dominion	100118	FTNN	537	196,005	10/31/2017	Yes	Part-284 transportation service used to transport gas from the TETCO interconnect at Oakford (537 MMBtu) to the Leidy Group Meter (537 MMBtu).
RI	Narragansett Electric	Dominion	700086	FTGSS	2,061	311,211	3/31/2017	Yes	Transportation contract used to transport gas from DTI-GSS #300169 (2,061MMBtu) to the TETCO interconnect at Chambersburg, PA (2,061 MMBtu).
VG	Narragansett Electric	Dominion	700087	FTGSS	5,324	803,924	3/31/2020	Yes	Transportation contract used to transport gas from DTI-GSS #300170 (5,324MMBtu) to Ellisburg, PA (5,324 MMBtu).
VG	Narragansett Electric	Iroquois	50001	RTS-1	1,012	369,380	11/1/2017	Yes	Transportation contract used to transport gas from Waddington (1,012 MMBtu) to the IGTS interconnect with TGP at Wright, NY.

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
BW	Narragansett Electric	National Fuel	E11395	EFT	1,177	429,605	3/31/2017	Yes	Part-284 transportation service (365-day) used to transport gas from TETCO (907 MMBtu) and NF Storage (270 MMBtu) to Transco - Wharton (1,177 MMBtu). (No longer have NF storage).
VG	Narragansett Electric	Tennessee	1597	FT-A	5,000	1,825,000	10/31/2019	Yes	Transportation service used to transport gas from Zn1 800 Leg (1,050 MMBtu), Zn1 500 Leg (2,200 MMBtu), and Zn 0 100 Leg (1,750 MMBtu) to National Grid city gates at Pawtucket, RI (5,000 MMBtu).
VG	Narragansett Electric	Tennessee	8516	FT-A	5,000	1,825,000	10/31/2020	Yes	Transportation service used to transport gas from Zn1 800 Leg (1,050 MMBtu), Zn1 500 Leg (2,200 MMBtu), and Zn 0 100 Leg (1,750 MMBtu) to National Grid city gates at Pawtucket, RI (5,000 MMBtu).
VG	Narragansett Electric	Tennessee	10807	FT-A	10,836	3,955,140	3/31/2017	Yes	Transportation service used to transport gas from Ellisburg (6,581 MMBtu) and Nothern Storage (4,255 MMBtu) to National Grid city gates at Pawtucket, RI (10,836 MMBtu).
VG	Narragansett Electric	Tennessee	39173	FT-A	1,067	389,455	10/31/2019	Yes	Transportation service (365-day) used to transport gas from Niagara River (1,067 MMBtu) to National Grid city gates at Pawtucket, RI (1,067 MMBtu).
PG	Narragansett Electric	Tennessee	62857	FT-A	19,335	7,057,275	4/30/2017	Yes	Transportation service used to transport gas from Zn1 800 Leg (4,060 MMBtu), Zn1 500 Leg (8,691 MMBtu), Zn0 100 Leg (6,022 MMBtu), and Zn1 100 Leg (562 MMBtu) to National Grid city gates at Pawtucket, RI (4,335 MMBtu), Cranston (10,000 MMBtu), and Smithfield (5,000 MMBtu).
PG	Narragansett Electric	Tennessee	62930	FT-A	15,000	5,475,000	8/31/2017	Yes	Transportstion service used to transport gas from the interconnect at Dracut (15,000 MMBtu) to National Grid city gate - Cranston (9,000) and National Grid city gate - Pawtucket, RI (6,000 MMBtu).
NGRI	Narragansett Electric	Tennessee	64025	FT-A	5,220	1,905,300	10/31/2027	No	TGP ConneXion - Transportation service used to transport gas from Tx Zone 0 (5,220 MMBtu) to National Grid city gates at Lincoln, RI (2,610 MMBtu) and Smithfield, RI (2,610).
NGRI	Narragansett Electric	Tennessee	64026	FT-A	6,380	2,328,700	10/31/2027	No	TGP ConneXion - Transportation service used to transport gas from Tx Zone 0 (6,380 MMBtu) to National Grid city gates at Lincoln, RI (3,190 MMBtu) and Smithfield, RI (3,190).
VG	Narragansett Electric	Tennessee	95345	FT-A	1,000	365,000	10/31/2017	Yes	Transportation service used to transport gas from interconnect at Wright, NY (1,000 MMBtu) to National Grid city gates at Lincoln (1,000 MMBtu).
PG	Narragansett Electric	Texas Eastern	330844	FTS	6,377	2,327,605	10/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Leidy, PA (6,377 MMBtu) to interconnect with AGT at Lambertville, NJ or Hanover, NJ (6,377 MMBtu).
BW	Narragansett Electric	Texas Eastern	330845	FTS	537	196,005	10/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Leidy, PA (537 MMBtu) to interconnect with AGT at Lambertville, NJ or Hanover, NJ (537 MMBtu).
BW	Narragansett Electric	Texas Eastern	330867	FTS-5	813	296,745	3/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (813 MMBtu) to Lambertville, NJ (813 MMBtu).
VG	Narragansett Electric	Texas Eastern	330870	FTS-5	1,000	365,000	3/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (1,000 MMBtu) to Lambertville, NJ (1,000 MMBtu).

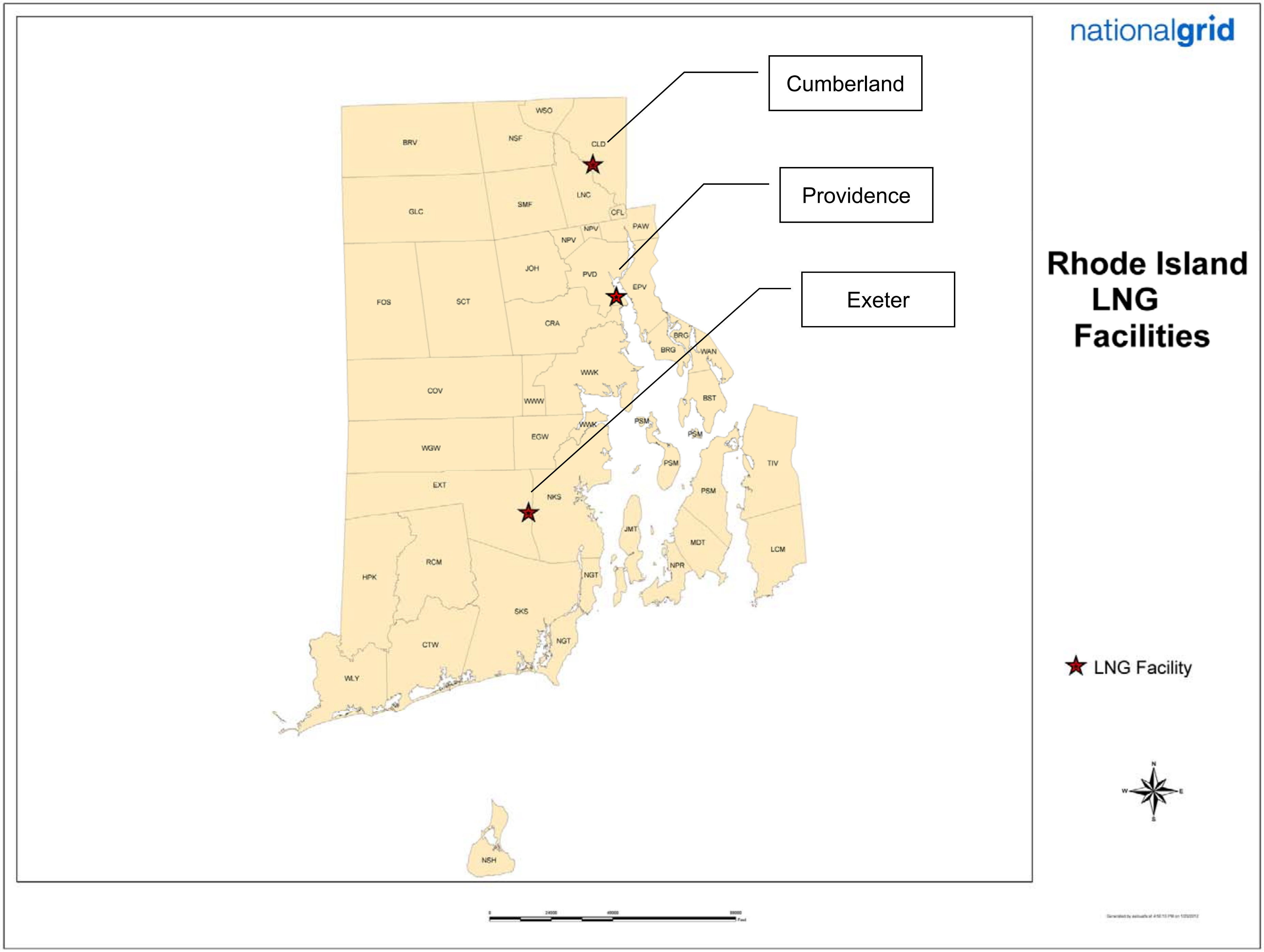
Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
PG	Narragansett Electric	Texas Eastern	330907	FTS-5	248	90,520	3/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (248 MMBtu) to Lambertville, NJ (248 MMBtu).
PG	Narragansett Electric	Texas Eastern	331722	FTS-7	538	196,370	3/31/2017	Yes	Part- 157 (7C) transportation service used to transport gas from Oakford, PA (538 MMBtu) to either interconnects at Lambertville or Hanover, NJ (538 MMBtu).
PG	Narragansett Electric	Texas Eastern	331801	FTS-8	79	28,835	3/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Leidy, PA (38 MMBtu) to either interconnects at Lambertville or Hanover, NJ. In addition, Oakford, PA (41 MMBtu) to either interconnects at Lamberville or Hanover, NJ.
BW	Narragansett Electric	Texas Eastern	331802	FTS-8	187	68,255	3/31/2017	Yes	Part-157 (7C) transportation service used to transport gas from Leidy, PA (89 MMBtu) to either interconnects at Lambertville or Hanover, NJ. In addition, Oakford, PA (98 MMBtu) to either interconnects at Lamberville or Hanover, NJ.
PG	Narragansett Electric	Texas Eastern	331819	FTS-8	4,745	1,731,925	3/31/2017	Yes	Part- 157 (7C) transportation service used to transport gas from Oakford, PA (4,745 MMBtu) to either interconnects at Lambertville or Hanover, NJ (4,745 MMBtu).
BW	Narragansett Electric	Texas Eastern	800156	SCT	2,099	766,135	10/31/2017	Yes	Part-284 transportation contract used to transport gas from the access areas at STX (585 MMBtu oper. entitle.), ETX (392 MMBtu oper. entitle.), WLA (900 MMBtu oper. entitle.), and ELA (1,504 MMBtu oper. entitle.) to the TETCO interconnect with AGT at Lambertville, NJ (2,099 MMBtu).
BW	Narragansett Electric	Texas Eastern	800173	SCT	1,474	538,010	10/31/2017	Yes	Part-284 transportation contract used to transport gas from the access areas at STX (401 MMBtu oper. entitle.), ETX (269 MMBtu oper. entitle.), WLA (617 MMBtu oper. entitle.), and ELA (1,031 MMBtu oper. entitle.) to the National Fuel interconnect at Holbrook, PA (925 MMBtu) and Oakford, PA (549 MMBtu).
PG	Narragansett Electric	Texas Eastern	800303	CDS	45,934	16,765,910	10/31/2017	Yes	Part-284 transportation contract used to transport gas from the access areas at STX (14,193 MMBtu oper. entitle.), ETX (9,523 MMBtu oper. entitle.), WLA (21,846 MMBtu oper. entitle.), and ELA (31,460 MMBtu oper. entitle.) to the TETCO interconnect with AGT at Lambertville, NJ (45,934 MMBtu) or Hanover, NJ (18,656 MMBtu) or Zone M3 Storage Point (6,665 MMBtu).
PG	Narragansett Electric	Texas Eastern	800440	CDS	944	344,560	10/31/2017	Yes	Part-284 transportation contract used to transport gas from TETCO FSS-1 #400515 to the TETCO interconnects at Lambertville, NJ (405 MMBtu) and Hanover, NJ (539 MMBtu).
NGRI	Narragansett Electric	TransCanada	42386	FT	1,012	369,380	10/31/2022	No	Transportation service used to transport gas from the Union Gas interconnect at Parkway to the interconnect with Iroquois Gas Transmission at Waddington, NY (1,012 MMBtu).
PG	Narragansett Electric	Transco	9081767	FT	1,240	452,600	3/31/2017	Yes	Part-284 transportation service used to transport gas from the National Fuel interconnect at Wharton (1,240 MMBtu) to the Algonquin interconnect at Centerville, NJ (1,240 MMBtu).
NGRI	Narragansett Electric	Union Gas	M12164	FT	1,025	374,125	10/31/2018	Yes	Transportation service used to transport gas from Dawn, Ontario to the interconnect with TransCanade Pipeline at Parkway (1,025 MMBtu).

Note: If volumes transported to points other than primary points as listed on the contract, maximum commodity rate per TGP's tariff apply.

NATIONAL GRID - RHODE ISLAND ASSETS
Storage Contracts

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	MDWQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
PG	Narragansett Electric	Columbia	9630	FSS	2,545	203,957	4/1/2040	No	Part-284 storage service that provides storage capacity with an injection rate of 2,545 MMBtu/day.
RI	Narragansett Electric	Dominion	300168	GSS	1,401	154,050	3/31/2020	Yes	Part-284 storage service that provides storage capacity with an injection rate of 856 MMBtu/day.
RI	Narragansett Electric	Dominion	300169	GSS	2,061	206,100	3/31/2018	Yes	Part-284 storage service that provides storage capacity with an injection rate of 1,145 MMBtu/day.
RI	Narragansett Electric	Dominion	300170	GSS	5,324	490,340	3/31/2020	Yes	Part-284 storage service that provides storage capacity with an injection rate of 2,724 MMBtu/day.
RI	Narragansett Electric	Dominion	300171	GSS	2,617	188,814	3/31/2018	Yes	Part-284 storage service that provides storage capacity with an injection rate of 1,049 MMBtu/day.
RI	Narragansett Electric	Dominion	600045	GSS-TE	14,337	1,376,324	3/31/2018	Yes	Part-157 (7C) storage service that provides storage capacity with an injection rate of 7,647 MMBtu/day.
RI	Narragansett Electric	Tennessee	501	FSMA	10,920	605,343	10/31/2020	Yes	Storage service that provides storage capacity at an injection rate of 4,036 MMBtu/day.
PG	Narragansett Electric	Tennessee	62918	FSMA	10,249	210,000	10/31/2020	Yes	Storage service that provides storage capacity at an injection rate of 1,400 MMBtu/day.
BW	Narragansett Electric	Texas Eastern	400185	SS-1	665	51,990	4/30/2017	Yes	Part-284 storage service that provides storage capacity with an injection rate of 267 MMBtu/day. [from Oakford and Leidy storage fields to interconnect at Lambertville, NJ (349 MMBtu) and interconnect at Hanover, NJ (506 MMBtu).]
PG	Narragansett Electric	Texas Eastern	400221	SS-1	14,137	1,188,033	4/30/2017	Yes	Part-284 storage service that provides storage capacity with an injection rate of 6,107 MMBtu/day. [from Oakford and Leidy storage fields to interconnect at Lambertville, NJ (8,017 MMBtu) and interconnect at Hanover, NJ (11,515 MMBtu).]
PG	Narragansett Electric	Texas Eastern	400515	FSS-1	944	56,640	4/30/2017	Yes	Part-284 storage service that provides storage capacity with an injection rate of 291 MMBtu/day.

Chart IV-C-4



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Facilities
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