nationalgrid

Raquel J. Webster
Senior Counsel

June 30, 2020

BY ELECTRONIC MAIL

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

RE: National Grid's Gas Long-Range Resource and Requirements Plan
Forecast Period 2020/21 to 2024/25
Docket No. 5043

Dear Ms. Massaro:

I have enclosed an electronic version of National Grid's[1] Gas Long-Range Resource and Requirements Plan (Long-Range Plan) for the forecast period 2020/21 to 2024/25.[2] The Company is submitting the Long-Range Plan to the Rhode Island Public Utilities Commission (PUC) pursuant to R.I. Gen. Laws § 39-24-2, which requires that the Company file the Long-Range Plan with the PUC on a bi-annual basis. In addition, the Company is also submitting the Long-Range Plan to the Rhode Island Division of Public Utilities and Carriers (Division) to fulfill the purposes of the proposal contained in the February 20, 2019 Joint Memorandum of the Company and the Division in Docket No. 4816.

The Long-Range Plan consists of a long-range energy plan for the five-year period subsequent to the date of this filing and includes all assumptions and methodologies that the Company used in formulating the plan. The Long-Range 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 Long-Range Plan includes the following information: (i) a description of the methodology the Company uses to forecast demand on its system; (ii) a discussion of the process and assumptions the Company uses to develop its resource portfolio to meet customer requirements under design-weather conditions; (iii) a complete inventory of the expected available resources in the Company's portfolio, and (iv) a demonstration of the adequacy of the portfolio to meet customer demands under a range of weather.

---

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).
[2] Because of the COVID-19 Pandemic emergency period, the Company is providing a PDF version of the above-referenced transmittal. The Company is providing the PUC with one copy of the hard copy and, if needed, additional hard copies at a later date.

40 Sylvan Road, Waltham, MA 02451
T: 781-472-0531 ■ raquel.webster @nationalgrid.com ■ www.nationalgrid.com

The Long-Range Plan includes confidential gas cost pricing information and contract terms, which are provided in Exhibits 18, 19, 20, and 21. Therefore, the Company has provided a redacted and confidential version of the Long-Range Plan and has requested confidential treatment of Exhibits 18, 19, 20, and 21 pursuant to R.I. Gen. Laws § 38-2-2(4)(B) and Rule 810-RICR-00-00-1.3(H) of the PUC's Rules of Practice and Procedure.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-472-0531.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Leo Wold, Esq.
Al Mancini, Division
John Bell, Division

STATE OF RHODE ISLAND
RHODE ISLAND PUBLIC UTILITIES COMMISSION

Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25	))))))	Docket No. _________

NATIONAL GRID'S MOTON FOR PROTECTIVE
TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] respectfully requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Rule 810-RICR-00-00-1.3(H) of the PUC's Rules of Practice and procedure (Rule 1.3(H)) and R.I. Gen. Laws § 38-2-2(4)(B). The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On June 30, 2020, the Company submitted its Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25 (LRP) in the above-captioned docket. The LRP includes confidential gas cost pricing information and contract terms, which are provided in Exhibits 18, 19, 20, and 21. In accordance with Rule 1.3(H)(3), National Grid has provided a redacted public version and confidential version of the LRP. Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the gas cost pricing information and contract terms contained in Exhibits 18, 19, 20, and 21.

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

II. LEGAL STANDARD

Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal*, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The gas cost pricing information and confidential contract terms – which are provided in Exhibits 18, 19, 20 and 21– are confidential and privileged information of the type that National Grid would not ordinarily make public. As such, the information should be protected from public disclosure. Public disclosure of such information could impair National Grid's ability to obtain advantageous pricing or other terms in the future, thereby causing substantial competitive harm. Accordingly, National Grid is providing the information on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID

By its attorney,

Raquel J. Webster, Esq. (Bar #9064)
40 Sylvan Road
Waltham, MA 02451
Tel. 781-472-0531
Raquel.Webster@nationalgrid.com

Dated: June 30, 2020

National Grid

The Narragansett Electric Company

Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25

June 30, 2020

RIPUC No. 5043

Submitted to:
Rhode Island Public Utilities Commission
Rhode Island Division of Public Utilities and Carriers
Submitted by:

nationalgrid

I. Introduction

This filing presents the Long-Range Resource and Requirements Plan (Long-Range Plan) for The Narragansett Electric Company d/b/a National Grid (Company) for the gas supply forecast period November 1, 2020 through October 31, 2025. The Company is a public utility under the provisions of R.I. Gen. Laws § 39-1-2 and provides natural gas sales and transportation service to approximately 269,000 residential and commercial customers in 33 cities and towns in Rhode Island. The Company is submitting this Long-Range Plan to the Rhode Island Public Utilities Commission (PUC) pursuant to R.I. Gen. Laws § 39-24-2, which requires that the Company file the Long-Range Plan on a bi-annual basis. In addition, the Company is also submitting this Long-Range Plan to the Rhode Island Division of Public Utilities and Carriers (Division) to fulfill the purposes of the proposal contained in the February 20, 2019 Joint Memorandum of the Company and the Division in Docket No. 4816 (Joint Memorandum).[1]

This Long-Range Plan consists of a long-range energy plan for the five-year period subsequent to the date of this filing and includes all assumptions and methodologies that the Company used in formulating the plan. In addition, Section V of this Long-Range Plan contains a description of the information to be included in the Long-Range Plan, pursuant to the Joint Memorandum, together with a reference to the specific section of the Long-Range Plan or Exhibit where such information can be found. This 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, this Long-Range Plan includes the following information: (i) a description of the methodology the Company uses to forecast demand on its system; (ii) a discussion of the process and assumptions the Company uses to develop its resource portfolio to meet customer requirements under design-weather conditions; (iii) a complete inventory of the expected available resources in the Company's portfolio, and (iv) a demonstration of the adequacy of the portfolio to meet customer demands under a range of weather.

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, Commercial, and Industrial markets. To determine the projected growth over the forecast period, the econometric models used historical economic, demographic, and energy price data, and weather data to determine total energy demand. The Company then

[1] On October 30, 2018 in the Company's 2018 Gas Cost Recovery (GCR) proceeding in Docket No. 4872, the PUC ordered that the Company and the Division to submit the Joint Memorandum in Docket No. 4816 outlining each of their recommendations for improving the Long-Range Plan as it relates to the annual GCR filing. On February 20, 2019, the Parties submitted the Joint Memorandum in compliance with the PUC's October 30, 2018 order in Docket No. 4872. The Joint Memorandum provided that the annual Long-Range Plan filings would be submitted in June, as soon as practical, following the release of the Company's annual forecast, permitting the Company to base its annual forecast on the most recent customer usage data, and prior to the Company's annual GCR filing. It also stated that the annual Long-Range Plan filings will include certain information, which is summarized in more detail in Section V, *infra*.

analyzed load reductions it expects to achieve through the implementation of its revised energy-efficiency programs because such reductions are exogenous to the demand forecast generated by the econometric models. The Company's forecast is based on the April 2020 economic forecast from Moody's Analytics, Inc. that includes its first estimates of the impact that COVID-19 will have on the Rhode Island economy.

The results of the Company's Base Case retail demand forecast (see Exhibit 1) indicates that, over the five-year forecast period Planning Year 2021 through Planning Year 2025, the residential heating market is projected to increase by an average of 368,000 dekatherms per year, the Residential Non-Heating market is projected to decrease by an average of 25,000 dekatherms per year, and the Commercial and Industrial Sales markets are projected to grow by 179,000 dekatherms 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 the models are based.

As explained below, the Company's demand forecast is then converted to supply requirements at the Company's city gates. The end result of the forecasting process is that projected sendout requirements increase over the five-year forecast period, averaging 650 MDth (approximately 1.8 percent) 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". This Long-Range Plan relies on the planning standards as defined in the Company's 2018 Long-Range Plan. The Company's design year is defined as 6,250 heating degree days (HDD) with a probability of occurrence of 1 in 37.47 years, and its design day is defined as 68 HDD with a probability of occurrence of 1 in 58.92 years. The Company has also included its design hour planning standard, which represents a 5% peak-hour factor (i.e. the peak hour requirement represents 1/20th of the peak day requirement). 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 five-year forecast period by an average of 741 MDth, or approximately 1.8 percent, per year (see Section III.F.), and design day sendout to increase by an average of 7,481 Dth, or 1.9 percent, per year. The design hour is also expected to increase over the forecast period (see Exhibit 2).

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) 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 and a cold snap weather scenario. 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 (January 8 - January 21) by evaluating January weather data from 1977/78 to 2016/17. The Company uses the results of the cold snap scenario to test the adequacy of inventories and refill requirements. The Company also applies the peak-hour requirement to its Synergi Gas® network analysis modeling software. To meet design requirements throughout the forecast period, incremental resources are needed.

Communications regarding this Long-Range Plan should be directed as follows:

Raquel J. Webster, Esq.
The Narragansett Electric Company
d/b/a National Grid
40 Sylvan Road
Waltham, MA 02451
781-472-0531
Raquel.Webster@nationalgrid.com

With a copy to:

Elizabeth C. Arangio
Director, Gas Supply Planning
The Narragansett Electric Company
d/b/a National Grid
40 Sylvan Road
Waltham, MA 02451
(781) 907-1639
Elizabeth.Arangio@nationalgrid.com

III. Forecast Methodology

III.A. Introduction

The Company's forecast methodology supports its supply planning goal to ensure that it maintains sufficient supplies 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 to ensure that the portfolio has sufficient resources for the upcoming winter period and sufficient time to contract for additional resources should they be required. The term "customer" as used herein means those customers for whom the Company must make capacity planning decisions.[2]

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 developed the retail forecast in this Long Range Plan in mid-2020 and, absent unanticipated modifications, it will be the same forecast that will be used in the Company's 2020 Gas Cost Recovery filing.

The Company models its daily resources and requirements with its SENDOUT® linear programming software modeling package and, therefore, a forecast of daily customer requirements as inputs for the model.

Accordingly, the Company developed five-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, Commercial, and Industrial 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] The Company makes capacity planning decisions for its Sales and non-Capacity Exempt Transportation (Customer Choice) customers.

(2) Develop Reference Year Sendout Using Regression Equations

The daily values of the Company's wholesale sendout in the reference year (April 2019 – March 2020) 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.

(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 forecast period.

(4) Determine Design Weather Planning Standards

The Company performs a determination of 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.

(6) Spatial (zip code) Peak Volume Forecast

For each zip code, customer monthly billing data is used to build monthly meter count and volume models for the major rate codes. Then, an optimization process is employed to convert this zip code level monthly volume forecast into daily values. The Company then ensures that this design weather zip code level forecast sums to the Company-level forecast to provide a zip code level view of design day customer requirements for system planning purposes.

Based on the forecast, the Company projects Base Case growth in customer requirements for its Sales and Customer Choice customers of 2,964 MDth over the five-year period, or 741 MDth per year (assuming normal weather) (see Section III.D.2.). Overall, this growth in firm sales represents a 7.2 percent total increase in sendout requirements over the forecast period, or 1.8 percent per year on average.

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

III.B. Retail 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 2020 to define the dependent variables in its econometric models. The billing data was modeled at the level of four major classes of customers (Residential Heating, Residential Non-Heating, Commercial, Industrial). Each of these four classes included the Sales customer sub-class, the Customer Choice customer sub-class, and the "capacity-exempt" (i.e., grandfathered Transportation) customer sub-class. The table below lists the relevant major groups and the Company's internal rate codes used in the Company's analysis.

	Internal Rate Codes
Residential Heating	400, 402
Residential Non-Heating	401, 403
Commercial	404, 405, 406, 407, 408, 409, 410, 411, 412, 413, 414, 415, 416, 425, 433, 434, 439, 440, 443, 444, Z407, Z411, Z415
Industrial	417, 418, 419, 420, 421, 422, 423, 424, 428, 437, 438, 441, 442, Z419, Z423

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 rate code. 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 Exhibit 3 as the independent variables, the Company estimated statistically valid econometric equations for each customer class. The Company obtained the economic and demographic data from Moody's Analytics, Inc. (Moody's), using forecasts from April 2020.

The Company accounts for the impact of the COVID-19 pandemic on forecasted gas load in the econometric models. Moody's April 2020 baseline economic outlook for Rhode Island is a severe recession driven by COVID-19 in 2020. The forecast assumes that some businesses will be allowed to re-open beginning June 2020. This causes third and fourth quarter GDP to rise sharply from its second quarter lows, but only about half the loss is recovered by the end of the year. Without a vaccine or effective medical treatment for COVID-19, travel, tourism, hospitality and other important industries will remain severely curtailed, preventing a full economic rebound. The forecast assumes a vaccine by summer 2021, allowing the Rhode Island economy to fully reopen and recover. However, Moody's does not forecast a return to full employment until 2023.

Additionally, the Company tested time variables, actual Heating Degree Days, actual Billing Degree Days, and natural gas and oil prices from the U.S. Department of Energy, Energy Information Administration.

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. 4979 in its 2020 Energy Efficiency Program Plan, dated October 15, 2019, which was the most recent data available when the Company prepared the forecast. The Company subtracted the incremental savings from the programs that are not embedded in the historical data used to derive the statistical models because such savings are exogenous to the modeling effort.

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

The Company develops its retail demand forecast from econometric models of its customer billing data. The Company developed the retail forecast presented in this Long Range Plan in mid-2020, which is the same forecast that will be used in the Company's 2020 Gas Cost Recovery filing. Summary charts and tables comparing this forecast with the Company's 2019 forecast are presented in Exhibits 1 and 4 through 6.

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

On August 30, 2017, the Company filed its 2018-2020 Energy Efficiency and System Reliability Procurement Plan in Docket No. 4684. On September 1, 2020, the Company will file new three-year Energy Efficiency and System Reliability Procurement Plans for the period 2021-

2023. The primary goal of the Energy Efficiency 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. Gen. Laws § 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.

Because 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 to determine whether its retail demand forecast required any adjustment to reflect the increases in energy efficiency efforts. Analysis of the Company's historical energy efficiency programs shows that historical data should have embedded within annual savings of 472 MDth. These figures are based on the three-year average of 2017 through 2019 actual energy efficiency savings. The Company uses a three-year average in lieu of the most recent year to smooth out the year-to-year fluctuations that may occur. The Company's analysis indicated that a further incremental reduction ranging from 8 MDth/year in 2021 to 45 MDth/year in 2025 was required to reflect the projected energy efficiency impacts.

III.C. Translation of Retail Forecast 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 12 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 3.5.3 of the "R" statistical software package.[3]

III.C.1. Wholesale Volume by Division

To establish normal-year springboard sendout requirements, the Company developed a linear-regression equation for each of its four divisions (formerly Providence Gas, Westerly Gas, Bristol and Warren Gas, and Valley Gas) using data for the reference-year period April 1, 2019 through March 31, 2020. The Company's regression equation uses sendout as its dependent

3 "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: https://www.r-project.org/about.html (The R Project for Statistical Computing).

variable and temperature as its independent variable.[4]

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: (1) HDD data as provided by its weather service vendor Weather Services International, (2) HDD data lagged over two days, and (3) 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 or T.F. Green) as the source of the weather data used as the principal explanatory variable in its regression equations. The Company selected the T.F. Green weather station 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 10:00 a.m. to 10:00 a.m., which constitutes the gas day and, therefore, corresponds to the same daily time period of observation of the sendout data.

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, i.e., 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".[5]

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.

The Company's segmented model equation includes variables the following variables: 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 space heating 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, the sendout will increase, which agrees with what the Company typically 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 0 for Mondays through Thursdays, 1 on Fridays and Sundays, and 2 on Saturdays. The sign of the

---

[4] Sendout includes both Sales and supplier service (Customer Choice) customer requirements and the Company's Capacity Exempt customers.

[5] Source: "Segmented: an R package to fit regression models with broken-line relationships," R News, Volume 8/1, May 2008, at page 20.

coefficient (negative) implies that for a given HDD level, loads will be lower on Friday through Sunday as compared to Monday through Thursday (i.e., weekend compared to the workweek).

Finally, the Company has observed a correlation between lagged temperature and the residuals of the above equation, so the Company has 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 functional form of the equation, in pseudo code, is:

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

These regression equations capture the observed characteristics of the Company's sendout requirements by gas division. 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 set of reliable regression equations to describe wholesale gas sendout by division. Using a series of daily normal HDDs, these equations allow the Company to calculate its history of normalized wholesale gas sendout for each of its four gas divisions.

Exhibit 7, provided in Microsoft Excel format, contains the wholesale volume forecast by rate group for normal and design weather and SENDOUT forecasts (normal and design weather) for capacity planning purposes for volumes and costs.

III.C.2. Wholesale Volume by End-Use

In addition to its segmented regression equations for each gas division, the Company runs similar regression equations for the sum of its four divisions for its capacity-eligible FT-1, capacity-exempt, and non-firm sales customers to best characterize the daily usage patterns of each of these customer groups. Subtracting the daily actual volumes for each of these groups from total daily wholesale sendout, the Company can also characterize the daily usage patterns of its remaining customers: Sales and FT-2. The Sales and FT-2 data are combined since they are not daily-metered customers and their volumes can only be inferred.

These regression equations capture the observed characteristics of the Company's sendout requirements by end-use. The observed characteristics include the following: (1) sendout requirements are directly related to HDDs; (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 reliable regression equations to establish the basis upon which future sendout requirements can be forecast. Moreover, the Company has further developed a set of reliable regression equations to describe wholesale gas sendout by end-use. Using a series of daily normal HDDs, these equations allow the Company to calculate its history of normalized wholesale gas sendout by end-use.

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.C.3. Comparison of Historical Retail and Wholesale Volumes to Determine Unaccounted For Gas

To align its historical and forecasted retail volumes to its wholesale data, the Company calculates its unaccounted-for ('UFG') percentage by which the retail data will be inflated to wholesale levels. For the most recent (September 2018 – August 2019) period, the Company's monthly retail volumes match the wholesale volumes to within 3.0 percent, a value that both agrees with expected UFG and indicates that the Company has adequately captured all customer volumes.

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 HDDs for the T.F. Green (KPVD) weather station for the 10-year period from April 2007 through March 2017, with an average of 5,422 HDD, as documented in its 2017 rate case (RIPUC Docket No. 4770).

The Company then prepared a "Typical Meteorological Year" by selecting, for each calendar month, the month in the T.F. Green weather database that most closely approximated the 10-year average HDD and standard deviation for each month. A summary of the monthly averages for the T.F. Green weather site is listed in the chart below.

Month	HDD	Standard Deviation
Jan	1,083	8.7
Feb	946	7.8
Mar	812	7.6
Apr	464	6.9
May	191	5.4
Jun	41	2.4
Jul	0	0
Aug	2	0.2
Sep	65	3.0
Oct	316	6.8
Nov	610	7.5
Dec	892	7.9
Total	5,422	

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

For the third step of the Company's forecasting methodology set forth in Section III.A, above, the Company allocated the monthly retail volumes to the daily level based on the 2019/2020 reference-year regression equations, using normal year HDD, to yield the forecast of Sales, FT-2 (Customer Choice), and FT-1 (pipeline) customer requirements under normal weather conditions for its demand forecast, based on a 365-day year.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Heating Season	25,796	25,505	26,045	26,855	27,470	27,485
Non-Heating Season	10,431	10,646	10,986	11,235	11,232	11,269
Total	36,227	36,152	37,031	38,091	38,703	38,755
Per-Annum Growth	-	-75	879	1,059	611	52
Per-Annum Growth (%)	-	-0.2%	2.4%	2.9%	1.6%	0.1%

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

III.E. Design 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.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 instant Long-Range Plan relies on the planning standards as defined in its 2018 Long-Range Plan. The Company's design year and design day standards are listed in the chart below.

Element	Value
Design Year HDD	6,250
Frequency of Occurrence	1 / 37.47 years
Design Day HDD	68
Frequency of Occurrence	1 / 58.92 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 58.92 years as a result of its ongoing 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 6,040 observations at the T.F. Green weather site for the November through March periods of 1977/78 through 2016/17. In previous long-range supply plan submissions, the Company had selected the coldest day of each of the most recent 40 heating seasons reflected in the T.F. Green weather data. The change to evaluating a larger data set was necessitated because the distribution of coldest days in the earlier methodology is trending away from a normal distribution. Using its new methodology, the Company found that these 6,040 data points fell within a normal distribution with an average of 55.00 HDD and a standard deviation of 6.13 HDD.

In its design day standard, the Company examined the cost of potential customer curtailments through a cost-benefit analysis. 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 and Industrial customers would potentially incur economic damages associated with the loss of production on the day of the event.

In the Company's design day cost-benefit analysis, 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 set a range for design day planning purposes from approximately 64.3 to 71.0 HDD, with a midpoint of 67.3 HDD. Thus, the Company's design day standard of 68 HDD is within the range of values based on cost and benefit. The Company's analysis indicates that the frequency of occurrence of the Company's design day standard is once in 58.92 years.

III.E.2.b. Design Year Standard

In this filing, the Company defines its design year standard as 6,250 HDD, with a probability of occurrence of once in 37.47 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 HDDs for which the Company 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 HDD 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.

As a result of this analysis, the Company has determined that a design year standard of 6,250 HDD is an appropriate level. The Company's analysis indicates that the frequency of occurrence of the Company's design year standard is once in 37.47 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 Base Case 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.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Heating Season	29,821	29,490	30,115	21,050	31,762	31,762
Non-Heating Season	11,194	11,424	11,787	12,056	12,053	12,095
Total	41,015	40,914	41,903	43,106	42,816	43,878
Per-Annum Growth	-	-100	988	1,202	710	61
Per-Annum Growth (%)	-	-0.2%	2.4%	2.9%	1.6%	0.1%

Base Case Design Year Customer Requirements for Capacity Planning (MDth)

III.G. Spatial (Zip-code) Design Day Forecast

III.G.1. Purpose

The purpose of the spatial design day forecast is to provide the peak volume on the design day of each zip code for next five years.

III.G.2. Data

The data for this forecast includes: (1) customer history monthly billing data of each rate code for each zip code; (2) history weather data; (3) history economic data; (4) normalized weather data for future prediction; (5) forecast economic data; (6) zip code based saturation values; and (7) zip code moratorium/engineering constrains (if applicable).

III.G.3. Modeling and Forecasting Process

The entire modeling and forecasting process consists of the following major steps:

- Customer monthly billing data calendarization and monthly aggregation for each major ratecode;
- Zip code based weather data processing and heating degree day (HDD) calculation;
- Meter count number correction to remove outliers and adjust the shifts (big jump or drop) caused by rate code re-definition or some other issues;
- Building meter count monthly model of each major rate code for each zip code;
- Trimming meter count number with the saturation result and moratorium constrains;
- Building volume monthly model of each major rate code for each zip code;
- Monthly volume bill/unbill split;
- Estimate the peak volume on the design data by using an optimization process to provide a best allocation from monthly volume to daily volume. This is a key step for the entire peak volume forecast; and
- From this year (2020), the spatial design day forecast has been extended to a more granular level (Residential vs. Non-Residential) through a separate optimization problem which doubles variables.

III.H. Design Hour Requirements

Once the design day sendout requirement is established, the Company converts this sendout to a peak hour based on a 5% peak-hour factor (i.e. the peak hour requirement represents 1/20th of the peak day requirement). The Company then applies the peak-hour requirement to its Synergi network analysis modeling software by means of growth factors generated from the spatial (i.e., zip code) forecast. The resulting peak-hour Synergi models are used to perform various analyses necessary for distribution system operations (e.g., regulator pressure settings, LNG requirements) and capital planning. On January 29, 2019, Algonquin Gas Transmission, LLC (AGT), one of the interstate pipeline companies that serves the Company, notified the Company (and all AGT customers served by AGT's G Lateral pipeline) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes to calculated hourly flow limits at each take station. Under the Company's contracts with AGT, those calculated hourly flow limits are either 1/24th or 6% of the daily MDQ under each contract (see Exhibit 8 for the Company's daily and hourly contract quantities). The total calculated hourly flow limits for each take station are then equal to the combined calculated hourly flow limit for all contracts providing deliveries to each take station. Historically, AGT has not imposed any requirements that its customers manage hourly takes to fall within the calculated hourly flow limits, nor has AGT restricted the Company's ability to balance its overall takes across all take stations. The January 29, 2019 notice expired on April 1, 2019, and due to the overall mild winter of 2019/20, it was not reissued. However, the Company reasonably expects that AGT may issue a similar notice in the future. AGT may even issue the types of orders described in the January 29, 2019 notice without first issuing another warning should extreme cold temperatures or system issues arise. Accordingly, the Company is making planning decisions so that it is able to comply with any such future orders. Because the Company's peak hour is greater than the daily 1/24th and 6% combination, the Company will now need to ensure that it has sufficient deliverability to meet the peak hour requirements of all of its customers.[6]

III.I. Capacity Exempt Customer Requirements

Capacity Exempt customers are firm transporters on the Company's distribution system; however, the Company does not plan for their upstream resources. Supply for capacity exempt customers is provided by third-party marketers. Additionally, the Company's capacity eligible FT-1 customers do not receive the storage and supplemental portion of their supplies from the Company's resource portfolio. These storage and supplemental volumes must also be provided by third-party marketers. The Company's forecasting process does include a forecast of these capacity exempt and FT-1 loads for distribution system planning purposes (see table below).

Capacity Exempt and FT-1 Storage/Supplementals Load Summary (Dth)
Base Case Forecast

Normal Year						
	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
HS	3,214,423	3,315,517	3,315,422	3,316,331	3,323,416	3,332,290
NHS	3,066,575	3,065,469	3,066,110	3,072,550	3,080,541	3,079,973
Total	6,280,998	6,380,986	6,381,531	6,388,881	6,403,957	6,412,263
PA Growth		99,988	545	7,349	15,077	8,306
Pct Growth		1.6%	0.0%	0.1%	0.2%	0.1%
Design Year						
	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
HS	3,547,636	3,661,141	3,661,256	3,662,454	3,670,405	3,680,430
NHS	3,115,010	3,112,836	3,113,490	3,120,051	3,128,187	3,127,544
Total	6,662,646	6,773,976	6,774,746	6,782,505	6,798,593	6,807,974
PA Growth		111,330	770	7,759	16,087	9,381
Pct Growth		1.7%	0.0%	0.1%	0.2%	0.1%
Peak Day	42,486	43,972	43,988	44,016	44,119	44,255

Capacity Exempt and FT-1 Non-Pipeline Customer Requirements (Dth)

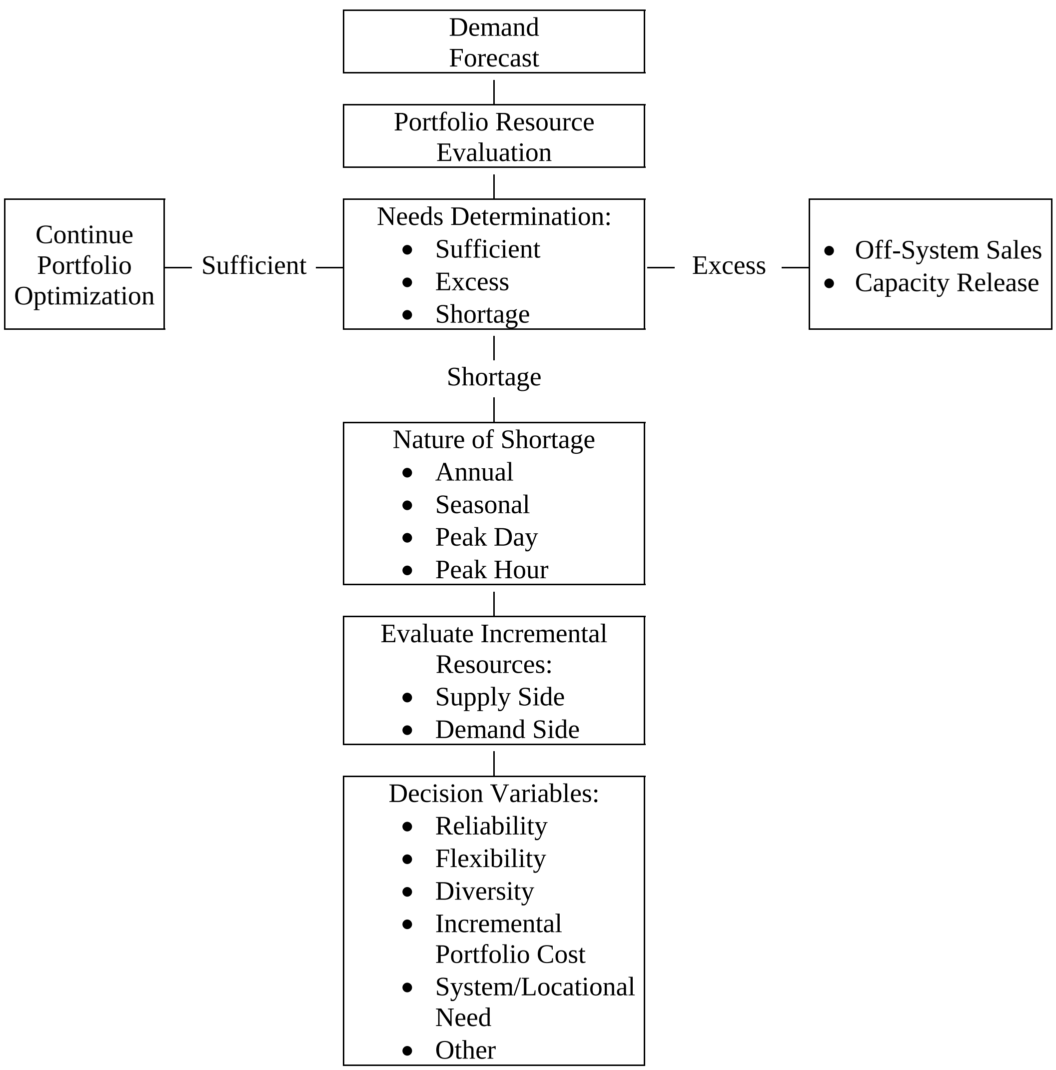
[6] The Company is also served by Tennessee Gas Pipeline (Tennessee). The Company's Tennessee contracts provide for 1/24th hourly flows.

The load duration curves for FT-1 Customers, Capacity exempt Customers and Non-Firm Customers are presented in Exhibits 9 through 11. The Company is providing the back up for this data in Microsoft Excel format.

IV. Design of the Resource Portfolio

IV.A. Gas Resource Portfolio

The Company maintains a resource portfolio that includes pipeline transportation, underground storage, and peaking resources to meet customer requirements on the forecasted design hour, design day, design year, and normal year including a mid-winter cold snap. To meet this obligation, the Company employs an established and reliable approach to demand forecasting and resource procurement. To this end, the Company identifies, evaluates, and acquires a mix of supplies and capacity that minimizes cost while ensuring the reliability of service to firm customers. The following figure is a schematic representation of the Company's resource evaluation and planning process.



IV.B. Analytical Process and Assumptions

To evaluate the adequacy of its portfolio relative to forecasted design day and design year customer requirements, the Company performs several analyses. The primary analysis is conducted utilizing the SENDOUT® model. The SENDOUT® model is a linear-programming optimization software tool used to assist in evaluating, selecting. and explaining long-term portfolio strategies. SENDOUT® allows the Company to model its resources realistically and to assess the adequacy and cost of its portfolio. SENDOUT® also aids the Company in evaluating options for incremental resources based on customer requirements and cost. Using the SENDOUT® model, 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 the Company's design day and design year 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 in the near term and over the longer term.

The Company also utilizes load duration curve analysis to assess the adequacy of its supply portfolio. Load duration curve analysis allows for a visual comparison of each day's forecasted requirements for the design year with the supplies and resources available to meet those requirements. This type of analysis, coupled with SENDOUT® studies, is helpful in identifying a design heating season shortfall in the supply portfolio.

The Company maintains Operational Balancing Agreements (OBA) with both AGT and Tennessee that allow the Company to balance receipts and deliveries across all gate stations on each of the respective pipelines. In January 2019, AGT issued a notice on its system warning that it might issue future orders that would limit the operational and planning flexibilities the Company historically has exercised pursuant to its contracts with AGT, AGT's Tariff and the OBAs, by requiring AGT customers served by the G Lateral to balance receipts and deliveries by gate station by hour[7]. In response to AGT's warning, the Company adjusted its planning to incorporate peak hour distribution system planning as a compliment to peak day planning.

The Company identifies the expected design hour requirements at each take station utilizing its Synergi Gas® network analysis modeling software. Synergi Gas® modeling software is used to simulate natural gas transmission and distribution systems. This hydraulic modeling software identifies, predicts, and helps the Company address its operational challenges, enabling day-to-day efficiency of gas distribution and transmission networks. Synergi Gas® software provides the results needed to make design, planning, and operating decisions using robust equations. The identified take station requirements are used to assess the adequacy of the gas supply portfolio, including expected deliveries by marketers, to identify any design hour shortfall. The Company compares the forecasted flows with the supply resources delivered to the take stations which include; contractual hourly entitlements of the Company's existing transportation contracts, on-system peaking assets, and expected deliveries by marketers.

[7] All of the Company's Tennessee contracts allow for 1/24th hourly deliveries, while the Company's Algonquin contracts allow for a combination of 1/24th and 6% hourly deliveries.

For the purpose of preparing this Long-Range Plan, the Company focused its analysis on design year forecast demand. However, it has also analyzed normal year forecasted demand and a cold-snap scenario using the Company's existing resource portfolio and proposed resources necessary to meet requirements. For the design year and normal year analyses, the Company compared resources and requirements for all firm planning load (i.e. firm sales and Customer Choice requirements) and also looked at resources and requirements applicable to firm sales customers only. The examination of these various scenarios enables the Company to test the adequacy and flexibility of the resource portfolio as described previously.

To perform the analysis of these scenarios, the Company incorporated several key assumptions. The Company used the NYMEX and basis forward curves dated June 8, 2020 as key pricing inputs to evaluate these scenarios. Throughout all of these scenarios, the Company has assumed that proposed changes to the customer Choice Program, discussed further in Section IV.E., are implemented in November 2020. The Company has also 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-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 (i.e. planning load). 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 except where explicitly discussed. Lastly, the Company assumed that its LNG supply contracts and its city gate supply arrangements (if required), will expire on the contract termination date, and are, therefore, not assumed to be available after the respective date. However, the Company has modeled the capabilities and costs of incremental assets required to meet design hour, design day, and design year requirements utilizing the best information available as of June 2020.

As previously stated, the Company has also examined its remaining supply portfolio after expected capacity releases to retail marketers and compared that portfolio to forecast requirements for sales customers. While the primary purpose of this analysis is to produce a forecast of gas costs for sales customers, this analysis is also useful to help the Company understand the optimal way to dispatch the assets it is likely to control on behalf of sales customers.

IV.C. Available Resources

This section describes the Company's current resource portfolio, the Company's expected resource portfolio given certain portfolio decisions the Company has made, and decisions the Company is considering. This section also discusses any modifications that the Company anticipates making to the portfolio during the forecast period to meet sendout requirements. As discussed in more detail 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 is included.

The following Exhibits detail the assets in the Company's supply portfolio:

- Exhibit 8 is a table showing the daily and the hourly contract quantities at each city gate for each transportation contract that delivers to the Company's city gates in Rhode Island on both Tennessee and Algonquin, in the Company's resource portfolio as of November 1, 2020.
- Exhibit 12 is a schematic of the Company's transportation and underground storage contracts effective as of November 1, 2020.
- Exhibit 13 is a table listing and description of each transportation and storage contract in the Company's resource portfolio as of November 1, 2020.
- Exhibit 14 is a listing of portfolio assets with the corresponding path to which each asset is assigned.

IV.C.1. Transportation Contracts

The Company has capacity entitlements on multiple upstream pipelines that allow for the delivery of gas to its city gates in Rhode Island. The Company has four city gate interconnects with Tennessee: Pawtucket/Cumberland, Lincoln, Smithfield and Cranston. Additionally, the Company has ten city gate interconnects with Algonquin; Dey Street, Westerly, East Providence, Portsmouth, Tiverton, Burrillville, Barrington, Bristol/Warren, Cumberland and Crary Street. The Company's transportation 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. The Company's transportation contracts are summarized on pages 1 through 3 of Exhibit 13.

IV.C.2. Underground Storage Services

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. By using long-haul capacity to fill storage, the Company is able to use those resources at a higher load factor. Underground storage supplies also allow the Company to serve peak-period requirements with off-peak priced gas supplies. Additionally, underground storage greatly enhances the flexibility of the Company's portfolio, allowing the Company to manage 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 (FS-MA) on the Tennessee pipeline. 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 Dth per 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 its firm storage contract, 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 is provided on page 4 of Exhibit 13.

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 on the coldest days.

IV.C.3.a. LNG Facilities

The Company maintains two permanent on-system LNG storage and vaporization facilities. These facilities enhance reliability and provide a source of supply for the distribution system. 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 supplies must be available throughout the heating season to ensure service to customers when the Company has exhausted its available pipeline supplies. It is the Company's practice to have its storage facilities full as of December 1 of each year.

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

Location	Facility Type	Maximum Vaporization [Dth per day]	Gross Storage Capacity [Dth]
Providence	LNG	95,000	600,000
Exeter	LNG	24,000	202,000
Total	**LNG**	**119,000**	**802,000**

IV.C.3.b. LNG Supply Contracts

Please see the table below for a listing of the LNG supply agreement(s) that are currently part of the Company's portfolio.

Supplier	MDQ (Dth)	ACQ (Dth)	Term
Constellation	2,750	349,250	Apr 1, 2020 – Nov. 30, 2020

In addition, as is the Company's practice, the Company contracts for trucking arrangements to guarantee the availability of trailers and drivers to truck LNG from the source point to the Company's LNG facilities throughout the year. The Company has contracted with

LP Transportation, Inc. to provide LNG trucking services to refill both NG LNG and Exeter for the 2020 off-peak season.

The Company is in the process of negotiating contracts for a limited amount of liquid refill for the 2021 off-peak season. In addition, the Company plans to contract for the following; (1) liquid refill for the 2020/21 peak season; (2) trucking arrangements for the 2020/21 peak season; and (3) trucking arrangements for the 2021 off-peak season.

IV.C.3.c. Portable LNG Vaporization Contracts

In addition to the Company's LNG storage facilities at Providence and Exeter, for the past several heating seasons, the Company has also staged portable LNG storage equipment in Cumberland, RI to support design hour system pressures and supply needs in the immediate area by utilizing the on-site vaporization capability. The Company has renewed its agreement for LNG storage services at Cumberland for the 2020/21 and 2021/22 heating seasons, with the optional of to an additional heating season. The Company discusses its long-term plans for the Cumberland facility in Section IV.C.10.

During the winter heating season, the Company has also installed temporary portable LNG vaporization equipment in Portsmouth to support its system on Aquidneck Island. This portable equipment provides critical pressure and supply support to Aquidneck Island should near-design day conditions arise. The Company's agreement for equipment rental continues through March 2021 with renewal rights through March 2023[8].

IV.C.3.c.i. 45 HDD Planning Requirement for Aquidneck Island

The Company has agreed to temporarily utilize portable LNG operations on Aquidneck Island as a contingency in the event of Company or non-Company upstream issues that affect pipeline deliveries into Portsmouth. Specifically, the Company plans to have portable LNG operations fully staffed and available for vaporization at 45 HDD conditions or colder with a vaporization capacity of 650 mcfh. The vaporization capacity of 650 mcfh provides approximately 75% of the hourly customer demand on Aquidneck Island at 45 HDD conditions and approximately 50% of the hourly customer demand at 68 HDD conditions. Demand-side initiatives are also being leveraged on Aquidneck Island to offset customer load including community initiatives to increase customer participation in energy efficiency programs and the use of gas demand response pilots.

IV.C.4. Long-Term Supply Agreements

[8] While the Company plans to use the Portsmouth equipment during the 2020/21 heating season, it is currently evaluating options to support Aquidneck Island in subsequent years.

Please see the table below for a listing of the Company's long-term supply agreements that are currently part of the Company's portfolio.

Contract	Description	MDQ (Dth)	ACQ (Dth)	Term
Constellation	Firm Supply @ Everett, MA into Tennessee	20,000	Dec19 – Mar20: 632,000 Dec20 – Mar21: 651,000 Dec21 – Mar22: 651,000	December 1, 2019 – March 31, 2022
Constellation	Firm Supply RI AGT City gates	14,100	507,600	December 1, 2019 – March 31, 2024

IV.C.5. Citygate Delivered Supply

From time to time, the Company can also contract for city gate 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 city gates by a third party. The purchasing of city gate delivered supplies can minimize the cost of the resource portfolio because the Company may have the opportunity 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, supply availability and overall reliability of the portfolio.

Based on the Company's current forecast requirements, it has not identified a need for additional city gate delivered supplies for the 2020/21 heating season. The Company will explore the need for these supplies upon the next update to its forecast.

IV.C.6. Asset Management Arrangements

At times, the Company may seek to enter into an asset management arrangement (AMA) for certain of the Company's assets. An AMA affords the Company the opportunity to place firm pipeline capacity into the control of a third party that is better able to manage the asset(s) without compromising access to liquid and reliable resources to firm gas customers. Currently, there are multiple assets being managed under AMAs. The Company issues a Request for Proposals (RFP) for AMAs for its Canadian transportation contracts on Union and TransCanada each year. The third parties managing these assets are more active in the Canadian markets than the Company and are therefore able to provide value to the Company's firm customers for the opportunity to manage the assets. During the 2019/20 heating season, the Company awarded AMAs pursuant to a competitive RFP process for a portion of its Columbia pipeline capacity and its Tennessee pipeline capacity from Dracut that is not supplied from the PNGTS path. The Company will continue to assess the portfolio to determine those assets that are well positioned to be managed by a third party.

For the upcoming winter season, the Company is prepared to issue RFPs for the management of its: (1) Columbia storage field and associated transportation capacity, and (2) Canadian assets, including the paths feeding Tennessee via PNGTS and Iroquois.

IV.C.7. Net Need Analysis

Exhibit 15 contains a comparison of current resources and forecast requirements. Exhibit 16 contains a comparison of current <u>and proposed</u> resources and forecast requirements. Each Exhibit contains summaries for the design day, the design heating season, the design non-heating season, and the design year. These tables show that the Company's proposed portfolio is sufficient to meet forecast customer requirements for the 2020/21 gas year, but in subsequent years, there is a need for incremental resources driven primarily by the expiration of the Company's long term supply contracts for city gate delivered supplies and supplies received at Everett.

The results of the Company's load duration curve analysis, in which it plots design year sales and transportation customer requirements against the supply portfolio, are provided in Exhibit 17, including both historical and future load duration curves. This analysis supports the conclusion above; beginning with the 2022/23 load duration curve and continuing through 24/25, the unserved area beneath the Customer Requirement line exceeds any surplus above the line indicating a need for incremental resources. The net need in the 2021/22 gas year occurs in the cold snap scenario, which is not represented in the load duration curves.

With respect to the design hour, the Company's Synergi analysis was completed using the Company's 2019 models with the design peak hour customer requirements adjusted to meet the 2020 forecast for the three firm customer requirement categories; Sales and FT-2, FT-1 and Capacity Exempt. Exhibit 2 shows the hourly imbalance at each take station for the five-year forecast period. This analysis indicates an overall portfolio deficit in the 2023/24 gas year, requiring incremental resources on both AGT and Tennessee.

IV.C.8. Changes and Proposed Additions to the Company's Resource Portfolio

There have been several changes and several proposed changes to the Company's gas supply portfolio since its last Long-Range Plan filing in July 2019.

(1) *<u>National Grid LNG (NGLNG)</u>*

The Company has entered into a Precedent Agreement for up to 2,616 Dth per day and 507,504 Dth per 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. Based on the most current information from NGLNG on the construction schedule, the liquefaction facilities are now expected to be available for refill in the 2022 off-peak season. The NGLNG facilities will allow the Company to 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.

(2) Northeast Energy Center, LLC (Northeast Energy)

The Company has entered into a Precedent Agreement for up to 1,780 Dth per day and 380,920 Dth per refill season for a term of 15 years, commencing upon completion of the necessary facilities. The Northeast Energy project is located in central Massachusetts and is expected to be in-service by the 2023 off-peak season. The Northeast Energy Project will allow the Company to utilize its existing Tennessee capacity to transport volumes from the Zone 4 production region to the proposed liquefaction facility located in Zone 6. The LNG will be trucked from the facility to the Company's LNG facilities in Rhode Island.

(3) PNGTS Capacity

Once fully phased in, the addition of the PNGTS capacity will reduce the Company's exposure at Dracut and allow the Company to access up to 29,000 Dth per day from Dawn, Ontario by way of agreements with Union, TransCanada, and PNGTS to deliver firm supplies into Dracut. The PNGTS Agreement will feed into the Company's existing Dracut capacity (29,000 Dth per day). The Company is currently able to flow 25,705 Dth per day of the PNGTS capacity and is anticipating the final phase of this project to go into service in November 2020.

(4) *Incremental Winter Liquid Volumes (LNG)*

To support the portable LNG storage operations at Cumberland and Portsmouth, the Company will need to pursue a supplemental winter-only LNG purchase agreement.

The Company will also need to purchase additional winter-only liquid for the Exeter and NGLNG/Providence LNG facilities in order to utilize them more actively for balancing purposes for the 2020/21 winter season.

(5) Columbia Contract Termination and Receipt Point Changes on Downstream AGT

The Company has terminated two transportation contracts with Colombia effective November 1, 2020. The terminations were supported by the Company's SENDOUT model analysis. Currently the Company has two transportation contracts with Columbia (contracts 31520 and 31522) originating at Pennsburg and Eagle. This capacity provides access to supplies that generally trade at a TETCO M3 price. If these contracts are not used and instead supplies are purchased directly at a TETCO M3 price on Algonquin, the variable transportation costs and fuel loss of these Columbia contracts can be avoided. Assuming normal weather, the variable Columbia pipeline transportation charges are approximately $5,009 per year based on the Company's analysis. The total annual fixed cost of maintaining the two contracts is $373,697 based on the current rates for Columbia's FTS service. The combined annual net savings resulting from terminating these contracts is estimated at $378,706. Therefore, the Company has decided to terminate these contracts upon their expiration date of October 31, 2020.

Coincident with the termination of the Columbia contracts, the Company will be changing the receipt point of the downstream Algonquin contract 90107 from Columbia-Hanover to Ramapo effective November 1, 2020. Doing so allows the Company to maintain primary point access to TETCO M3 supplies. This receipt point change was completed at no cost to the Company.

IV.C.9. Future Portfolio Renewal Decisions

During the forecast period, the Company will be faced with critical decisions regarding the expiration of a certain transportation, underground storage, and peaking contracts in the supply portfolio.

The Company will employ a two-step analysis to reach decisions 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. Where appropriate, the Company will solicit competitive bids to determine the lowest-cost available resource.

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 capacity[9] 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.10. Long-Term Cumberland Solution

For the past several winters, the Company's interim solution to meet customer requirements in northern Rhode Island and manage system pressures has depended upon portable

[9] "Legacy capacity" is defined herein as firm interstate pipeline transportation and storage service provided to the Company and other local distribution companies 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.

LNG operations at the former LNG plant on Scott Road in Cumberland, RI. The Company will continue to rely on the interim solution until a permanent solution is in service.

The Company completed its review of multiple options for a permanent solution to address capacity needs, driven by the peak hour requirements, in northern Rhode Island. Selection of a permanent solution focuses on securing additional infrastructure to the northern Rhode Island region to meet both design day and design peak hour needs. The Company has determined that the permanent solution is to rebuild the Scott Road take station and the Cumberland LNG facility.

The Company needs to rebuild the Scott Road take station to address several existing integrity issues. In addition, the Company will design the rebuild to ensure the flow capacity will meet long-term forecasted customer requirements. The Company started development of this project in April 2020, with a target gas in-service date of November 2023. Once rebuilt, the Company will have the capability to receive incremental volumes from Tennessee.

The Company needs to rebuild the LNG facility to meet forecasted design peak hour requirements. The Company will design the LNG facility to ensure the hourly flow capacity will meet the long-term forecasted design peak hour customer requirements. The Company started developing this project in April 2020. The target construction start date is April 2025. Until the LNG facility is in service, the Company will continue to operate portable LNG to meet the design peak hour requirements.

IV.C.11. Natural Gas Portfolio Management Plan (NGPMP)

In 2009, in Docket No. 4038, the PUC approved the Company's NGPMP, which discontinued contracting the natural gas portfolio from an external third-party asset management agreement, to a portfolio managed primarily by the Company. In March 2016, also within Docket 4038, modifications to the management of the Company's NGPMP were approved and designed to provide various financial, regulatory, and risk management benefits over previous asset management arrangements. The Company uses transportation contracts, underground storage contracts, peaking supplies, and supply contracts to purchase gas supplies to economically and reliably serve its sales customers. Additional purchases and sales may be made to 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 allows for sales customers to receive natural gas during periods of high-demand, and to optimize the value of an asset when not needed. Opportunities to optimize may be limited and are subject to prevailing market conditions, which may include: the fluctuation in the price of natural gas, the value of temporarily unused assets, the existence of excess transportation and storage capacity, and the opportunity to optimize delivered supplies as storage fill opportunities arise. Unless otherwise directed by the PUC, the Company will continue to manage the natural gas portfolio as specified in the NGPMP.

IV.D. Portfolio Costs

The Company plans its portfolio to meet the forecast design day and design annual requirements of its firm sales, FT-2, and a portion of its FT-1 customers. Detailed information regarding costs of the full portfolio are presented in Exhibits 18 through 21. Cost projections were developed using the New York Mercantile Exchange (NYMEX) forward curve from June 8, 2020 in conjunction with forecasted regional basis from a combination of public and internally developed forward price curves.

In Exhibit 18, the Company has provided a projection of costs for its full supply portfolio assuming design weather. This projection provides a sense of the overall variable and fixed costs for all customers, including transportation customers. By evaluating these costs assuming design weather, the variable costs of all portfolio assets are reflected, including peaking assets, which are unlikely to be needed during normal weather. This Exhibit is formatted similarly to exhibits provided in the Company's Gas Cost Reconciliation (GCR). Total annual fixed costs for the 2020/21 gas year are projected to be approximately $94 million for the Company's transportation, storage, and supply agreements. Of the $94 million, $16 million is attributable to estimated supplier fixed costs. These costs relate to LNG refill and trucking, city gate peaking services, and supplier reservation charges for Everett and Dracut supplies. This is an estimate as the supplies are not under contract at this time. Total annual variable costs for the same period are projected to be approximately $109 million assuming design weather. Combined fixed and variable costs are projected to be $203 million. On a unitized basis, as shown on Page 4 of Exhibit 18, the weighted average commodity cost is estimated to be $2.654 per dekatherm. For reference, the straight average NYMEX forward curve for the 2020/21 gas year is $2.622 per dekatherm.

In Exhibit 19, the Company has provided an estimate of the fixed and variable costs that will support the GCR, to be filed in August 2020. The GCR pertains solely to sales customers and assumes normal weather. The fixed costs of pipeline capacity and storage released to marketers are not included in the GCR, nor are the variable costs attributable to transportation customers. Total annual fixed costs for the 2020/21 gas year are projected to be approximately $80 million for the Company's transportation, storage, and supply agreements for sales customers. Total annual variable costs for the same period are projected to be approximately $73 million assuming design weather. Combined fixed and variable costs are projected to be $154 million. On a unitized basis, as shown on Page 4 of Exhibit 19, the weighted average commodity cost is estimated to be $2.552 per dekatherm.

Exhibit 20 provides the projected unitized costs by path for all customers and sales-only customers accounting for normal and design weather. Pages 1 through 4 of Exhibit 20 show the unitized 100% load factor cost of each path dispatched to meet customer requirements, which includes fixed costs, variable pipeline and storage costs, and commodity costs of gas supplies. Pages 5 through 8 of Exhibit 20 show the effective cost of each path at the expected load factor. These pages also include variable costs but differ from the prior pages in that the annual fixed costs for each path are unitized by the volume projected to be dispatched on each path. For paths with high load factors, the costs projected on pages 1 through 4 and on pages 5 through 8 will be relatively close; for paths with lower load factors, there will be a greater relative difference.

Exhibit 21 is an estimate of fixed costs by contract in the Company's portfolio including transportation contracts, storage contracts, and supply contracts. Pages 1 through 4 of Exhibit 21 show the unitized 100% load factor cost of each contract, which does not vary between normal and design weather. Pages 5 through 12 show the effective cost of each contract accounting for projected load factor.

IV.E. Customer Choice Program

IV.E.1 Overview of the Company's Customer Choice Program

The Company's Customer Choice Program is an optional supplier choice program that allows the Company's Small, Medium, Large, and Extra Large Commercial and Industrial (C&I) customers to purchase gas supplies from sources other than the Company for transportation service by the Company. The Company continues to provide distribution and related services to all of its customers, including those that receive gas supply from a third party. Service is classified as either Firm Transportation Service FT-1 or Firm Transportation Service FT-2.

FT-1 service is available only to Large and Extra Large C&I customers. This service provides firm transportation of customer-purchased gas supplies to customers who elect to have their gas usage recorded on a daily basis at the customer's point of delivery. This service requires daily balancing of deliveries and usage by the Marketer, which includes meeting the impact of unanticipated swings in weather and/or demand. The Company plans only for pipeline assets required to serve FT-1 customer requirements and does not plan for any storage and peaking assets required to serve these customers.

FT-2 service is available to all C&I customers. FT-2 service does not require the recording of daily gas usage at the customer's point of delivery, and as such, requires the Company to assume substantial responsibility for balancing the customer's deliveries and usage on a daily basis. Under FT-2 service, the Company informs the Marketer of the required deliveries for the upcoming gas day, and is responsible for meeting any difference between the forecast and actual quantities as a result of weather or other factors, through storage and peaking services. For this reason, the Company plans for pipeline, storage, and peaking assets to meet the peak day requirements of FT-2 service.

Currently, uunder the Company's Customer Choice Program, the Company assigns a pro rata share of its interstate pipeline resources to customers migrating to transportation service at the Company's average cost of these resources. Customers taking either FT-1 or FT-2 service are assigned certain pipeline assets. As discussed above, FT-2 customers are also allocated a portion of storage and peaking resources needed to meet peak day requirements. The storage and peaking resources are not physically released to customers, but are instead managed by the Company and provided to customers at the city gate. Mandatory capacity assignment enables the Company to ensure that there is adequate capacity upstream of its city gates and to maintain the operational integrity of the distribution system. It also prevents certain customers from avoiding responsibility for the cost of the Company's long-term capacity commitments given these customers' ability to avail themselves of competitive options.

Not all customers under the Company's Customer Choice Program are assigned capacity. Pursuant to the Settlement Agreement dated October 7, 1999, approved by the PUC in Docket No. 2902 (1999 Settlement Agreement), new customers who were classified as either Large or Extra Large C&I customers and who were not previously served on firm sales service were given a one-time option to waive the Company's assignment of pipeline capacity. This one-time election is built into the Company's Tariff today.

In addition, pursuant to the 1999 Settlement Agreement, firm transportation customers transporting prior to November 1, 1997 were also given the one-time option of waiving the Company's mandatory capacity assignment shortly after the PUC's approval of the 1999 Settlement Agreement. For "grandfathered" customers who elected this waiver, those customers were thereafter ineligible to return to the Company's firm sales service.

IV.E.2 Impact of the Customer Choice Program on Portfolio Planning

In the Company's 2018 Long-Range Plan filing, the Company provided the following high-level summary of the impact of the Customer Choice Program on portfolio planning:

> On September 8, 2014, the Company filed a proposal to make certain changes to its Customer Choice Program in Docket No. 4523. In summary, the Company proposed three specific changes. First, regarding pipeline delivery requirements, the Company proposed to require a certain level of daily pipeline receipts on each of the upstream pipelines, Algonquin and Tennessee. Second, regarding the peaking assets calculation, the Company proposed to modify the FT-2 Demand Rate and associated peaking purchases to include certain pipeline assets and associated supplies in the calculations to more accurately reflect the usage of such assets. Third, regarding daily nominations under operational flow order conditions, the Company proposed to require a certain level of pipeline deliveries before FT-2 storage and peaking assets could be nominated. The Company proposed such changes to address the overall design of the Company's Customer Choice Program, as well as the impact to the reliability of the overall gas resource portfolio and the appropriate allocation of costs among all customers. The proposed changes were accepted and went into effect on November 1, 2014. Since then, no other substantive changes have been made to the Customer Choice Program. However, as load on the distribution system continues to grow, the disconnect with how customers that have opted for Transportation service are actually served, as compared to how third-party marketers are obligated to serve them under the Customer Choice Program, continues to grow. This disconnect exists for all Transportation customers, including both those eligible for capacity assignment and those that are capacity exempt and, therefore, not eligible for capacity assignment. For example, under the Customer

Choice Program, a third-party marketer can elect to take assignment of a capacity path that delivers to the Algonquin-fed side of the distributions system on behalf of a customer that is physically served from the Tennessee-fed portion of the distribution system. Then, on a day-to-day basis, to serve that customer the marketer only has to deliver a minimum of 40 percent of the customer's supply on Tennessee, with the remainder delivered on Algonquin.[10] In these circumstances, the overall portfolio of assets, including on-system peaking, allow for the entire system to remain in-balance with the pipelines at the end of the day. Capacity-eligible customers share in the overall cost of the portfolio through mandatory capacity assignment; Capacity Exempt customers do not. This disconnect between where loads are and how they are served was exacerbated with the decommissioning of the Company's Cumberland LNG plant. The Company no longer has the on-system resource to balance loads in that "pocket" of the distribution system and has to rely on pipeline deliveries from third parties that do not all have primary point capacity to the Company's city gates in Rhode Island. This is not sustainable for the long-term reliability of the distribution system, especially given the capacity constraints that exist on the interstate pipelines serving New England, specifically Algonquin and Tennessee. The Company is in the initial stages of its analysis and will present its findings and recommendations once completed.

In the Company's 2019 Long-Range Plan filing, the Company provided the results of its initial analysis, looking at the total hourly supply/demand balance at each gate station on both Algonquin and Tennessee[11]. As part of total load, the Company included the load associated with all FT-1 customers, whether the Company plans on their behalf or whether or third-party marketer provides deliveries. This FT-1 load was mapped to the gate station each of the customers is served from and the total volumes third-party marketers are expected to deliver was mapped to the gate stations to which they deliver. The results of this analysis showed an hourly imbalance at several of the Company's gate stations on both Algonquin and Tennessee. To meet the forecasted peak hour requirements for 2019/20 winter season, the Company contracted for additional resources. The results of the analysis using updated forecasted information are presented in Exhibit 2.

IV.E.3. Future Changes to the Customer Choice Program

The impact of the Customer Choice Program on portfolio planning coupled with the capacity constraints that exist on the interstate pipelines serving New England, specifically Algonquin and Tennessee, have impelled the Company to re-examine its Customer Choice Program. In the Company's 2019 Long-Range Plan filing, the Company committed to considering the overall framework of the program and where appropriate seek to implement modifications to better align the program to support portfolio planning needs. Further, the review would consider several aspects of the Customer Choice Program including but not limited to; impact of customer load for which the Company is not responsible to plan for[12], capacity exempt

[10] Marketers are required to deliver a minimum of 40 percent on each pipeline and the remaining 20 percent on either or both pipelines.

[11] The analysis was performed using the June 2018 forecast for the 2019/20 through 2023/24 gas years.

[12] This load includes Capacity Exempt Customers as well as the storage and peaking load of the capacity eligible FT-1 Customers.

eligibility criteria, alignment of mandatory capacity release with customer location, nomination and pooling flexibilities and balancing and cashouts. The Company committed to presenting its recommendations once the review was completed. Further, the Company's 2019/20 GCR Docket No. 4963 approved the Division's recommendation for the Company to work with the Division to evaluate the Company's current cost allocation procedures for interstate pipeline firm transportation capacity assigned to firm transportation customers and to reflect modifications to the current approach, which addresses the allocation of fixed gas supply reservation charges, and to present those modifications in next year's GCR filing.

The Company plans to submit a filing, shortly after submission of this Long-Range Plan, detailing its proposal for modifications to the current Customer Choice Program. The Company's proposal will address the cost allocation procedures for interstate pipeline firm transportation capacity assigned to firm transportation customers as well as the allocation of fixed gas supply reservation charges associated with hourly peaking assets [13].

In summary, the modifications to the Customer Choice Program, proposed to be effective for this upcoming November (2020) include making available all significant capacity paths on Algonquin and Tennessee available to Marketers, whereby all Marketers would receive a pro-rata share of each capacity path based on the Company portfolio, thereby eliminating the current "pick a path" approach to capacity release, as well as the related commodity adjustment since Marketer will have access to largely the same assets as the Company. Exhibit 22 provides a summary of proposed releases to Marketers. The Company has compared the unitized fixed costs of its transportation contracts with the fixed costs of its proposed releases to marketers. On a unitized basis, the costs compare well; as shown in Exhibit 22, the average fixed cost of the Company's transportation portfolio is $0.838 per dekatherm per day while the average fixed cost of the proposed releases is $0.849 per dekatherm per day. The Company will explore minor adjustments to its allocation methodology to decrease the difference between these rates. The proposed changes will also allow the Company to better align receipts and deliveries, therefore assisting the Company to better manage pipeline balancing requirements, including gate station-specific operational flow orders.

As part of its review of the Customer Choice Program, the Company also considered changes to the Capacity Exempt criteria currently contained in the tariff, specifically the ability of Capacity Exempt customer to become Capacity Eligible. Because on the complexities, including operational feasibility, of such changes, the Company has bifurcated the issues and will file for the implementation of program modifications that can be implemented sooner rather than later, while continuing to pursue options for Capacity Exempt changes.

V. Fulfilment of the Joint Memorandum of the Company and the Division Regarding the Long-Range Plan

.

[13] The Company plans to include the proposal for the allocation of fixed gas supply reservation charges associated with hourly peaking assets in the Company's Distribution Adjustment Clause filing in August 2020.

The Joint Memorandum between the Company and the Division states that the annual Long-Range Plan filings will include certain information[14]. This listing of information is provided in the table below along with the referenced exhibit provided for in this filing.

[14] Pursuant to discussions with the Division, the Company and the Division have refined the list of information to be provided pursuant to the Joint Memorandum as part of the annual Long-Range Plan filings.

Item	Description	Reference
1	Retail volume forecast by rate group for normal weather	Exhibit 1 Exhibit 4
2	Retail meter count forecast by rate group for normal weather	Exhibit 5 Exhibit 6
3	Rhode Island Economic Forecast variables for normal weather	Exhibit 3
4	Wholesale volume forecast by rate group for normal and design weather EXCEL ONLY FOR 2020	Exhibit 7
5	SENDOUT forecasts (normal and design weather) for capacity planning purposes for volumes and costs.	Exhibit 7
6	Updated portfolio information showing all changes to the portfolio (capacity/supply/LNG), including: • Updated Exhibit 12 (schematic) if any changes have occurred; • Updated Exhibit 13 (a description of the contracts within the portfolio, including expiration date and evergreen provisions); • Updated Exhibit 8 (table showing the daily and the hourly contract quantities at each city gate for each transportation contract that delivers to the Company's city gates in Rhode Island on both Tennessee and Algonquin, in the Company's resource portfolio)	Exhibit 8 Exhibit 12 Exhibit 13
7	Detailed information on needs for upcoming winter season, including SENDOUT analysis showing derivation of need.	Exhibit 15
8	Discussion of subsequent four-years and associated need and what the Company is pursuing with potential suppliers and pipelines to meet customer requirements, as well as expected costs of options.	Exhibit 15 Exhibit 16
9	Provide historic (5-10 years) and projected (out 5 years) annual wholesale load duration curves showing the following: • Stack existing supply resources (by path) against the daily wholesale load duration curve for historic period; • Stack proposed supply resources (by path) against the daily wholesale load duration curves for the projected periods; • Stack existing supply resources (by path) against the daily wholesale load duration curves for the historic November-March period; • Stack proposed supply resources (by path) against the wholesale load duration curves for the projected November-March periods; and • The Company will endeavor to develop equivalent hourly wholesale load duration curves	Exhibit 17
10	For individually metered high load factor Transportation customers, the Company will develop aggregated annual historic (5-10 years) and projected (out 5 years) load duration curves. For those customers with hourly metering, the Company will endeavor to provide the historic (5 years) aggregated hourly load duration curve	Exhibit 9 Exhibit 10 Exhibit 11
11	The Company will provide fixed cost of existing and proposed supply resources on a dollar per dekatherm (Dth) per day basis (annualized). Once individualized, then the Company will provide the same annualized information by path.	Exhibit 18 through Exhibit 21
12	For each existing and proposed supply resource (by path), the Company will provide an estimated <u>effective</u> Fixed Cost (on a Dth per day basis) (i.e., taking into account load factor utilization) for the current period and forecasted time periods for both its normal and design weather scenario, which is the basis of the Company's decision-making.	Exhibit 18 through Exhibit 21

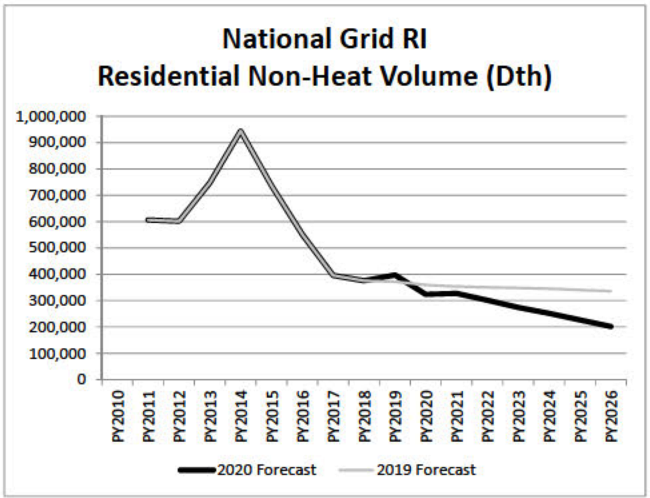
VI. Exhibits

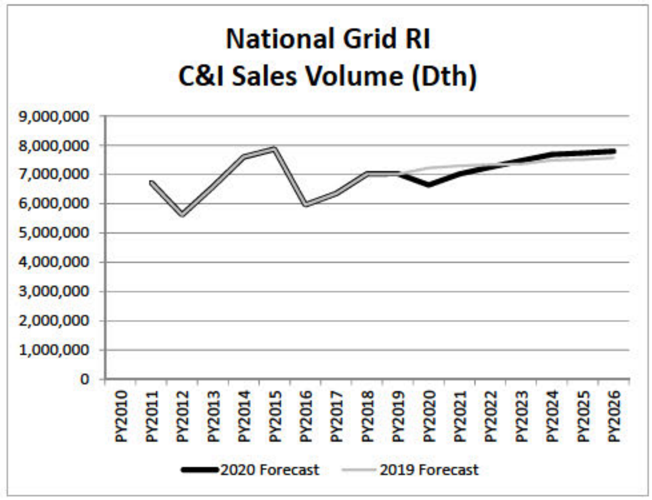
2020 National Grid RI Volume Forecast (Dth)
Planning Year (Nov-Oct)

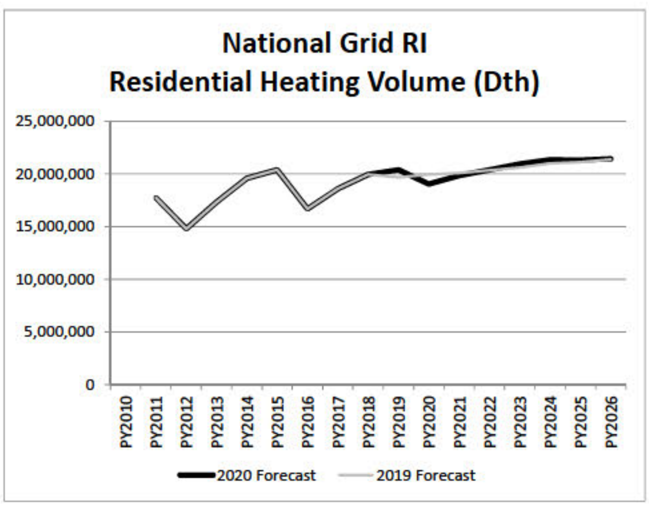
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,726,982	7,680,544	2,569,158	35,321,323	2,267,651	37,588,973
PY2012	601,399	14,783,757	5,621,832	7,610,425	2,333,884	30,951,297	2,195,914	33,147,211
PY2013	746,890	17,315,788	6,583,721	8,278,483	3,049,869	35,974,752	2,014,144	37,988,895
PY2014	944,174	19,573,872	7,599,237	8,563,673	3,548,382	40,229,338	1,793,702	42,023,040
PY2015	736,952	20,389,772	7,870,336	9,416,525	3,680,836	42,094,420	1,828,764	43,923,185
PY2016	551,336	16,675,372	5,959,428	8,656,943	3,569,930	35,413,008	1,865,144	37,278,152
PY2017	395,749	18,594,264	6,348,282	8,698,747	3,950,370	37,987,412	1,860,594	39,848,006
PY2018	375,500	19,943,386	7,021,056	9,022,578	4,205,501	40,568,021	1,938,339	42,506,360
PY2019	397,642	20,381,686	7,030,001	8,770,816	4,479,693	41,059,838	2,012,039	43,071,878
PY2020	323,837	19,039,603	6,639,392	8,251,676	4,300,551	38,555,058	1,890,633	40,445,691
PY2021	327,328	19,842,428	7,014,708	8,051,014	4,235,312	39,470,789	1,799,964	41,270,753
PY2022	301,598	20,377,128	7,254,018	8,426,323	4,388,407	40,747,475	1,880,060	42,627,535
PY2023	274,203	20,948,766	7,472,223	8,866,659	4,529,798	42,091,649	1,941,674	44,033,323
PY2024	251,856	21,339,906	7,686,813	8,908,249	4,589,397	42,776,222	1,936,813	44,713,035
PY2025	226,569	21,313,493	7,731,019	8,749,950	4,573,365	42,594,397	1,904,790	44,499,187
PY2026	201,699	21,431,465	7,791,207	8,647,306	4,584,956	42,656,633	1,884,881	44,541,514
PY2027	176,056	21,553,988	7,849,419	8,550,507	4,596,793	42,726,763	1,866,108	44,592,871
PY25/PY20	-6.9%	2 3%	3.1%	1.2%	1.2%	2.0%	0.1%	1 9%

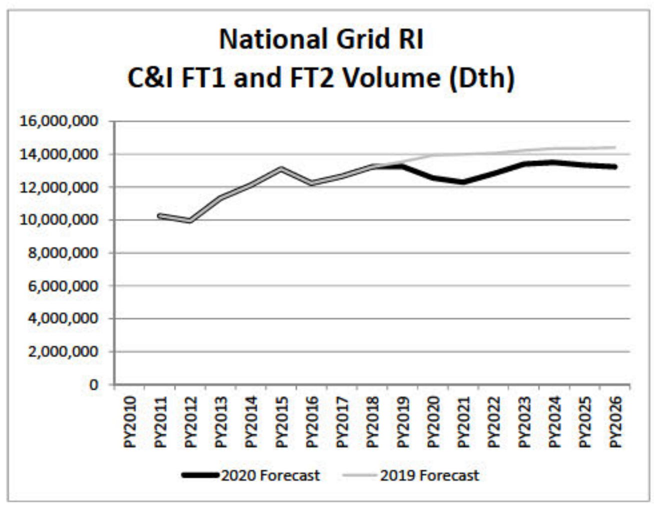
2019 National Grid RI Volume Forecast (Dth)
Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,723,757	7,680,544	2,569,158	35,318,097	2,267,651	37,585,748
PY2012	601,399	14,783,757	5,621,627	7,610,425	2,333,884	30,951,092	2,195,266	33,146,358
PY2013	746,890	17,315,788	6,580,974	8,278,483	3,049,869	35,972,004	2,014,144	37,986,148
PY2014	944,174	19,573,872	7,602,085	8,563,673	3,548,382	40,232,186	1,793,702	42,025,888
PY2015	736,952	20,389,772	7,870,135	9,416,525	3,680,836	42,094,220	1,828,764	43,922,984
PY2016	551,336	16,675,346	5,959,177	8,656,943	3,569,930	35,412,731	1,865,144	37,277,875
PY2017	395,746	18,594,052	6,347,744	8,698,747	3,948,471	37,984,761	1,860,594	39,845,355
PY2018	375,420	19,942,385	7,018,663	9,022,578	4,201,189	40,560,235	1,938,339	42,498,574
PY2019	371,670	19,674,485	7,013,029	9,100,758	4,433,548	40,593,490	2,049,221	42,642,712
PY2020	359,772	19,941,015	7,226,025	9,391,677	4,536,424	41,454,912	2,088,084	43,542,996
PY2021	354,474	20,078,627	7,298,114	9,450,501	4,536,318	41,718,034	2,090,170	43,808,204
PY2022	350,941	20,337,068	7,337,210	9,495,708	4,550,765	42,071,692	2,097,325	44,169,017
PY2023	347,655	20,593,684	7,358,498	9,663,594	4,560,920	42,524,350	2,104,822	44,629,172
PY2024	345,785	20,992,308	7,485,748	9,758,175	4,585,433	43,167,450	2,115,301	45,282,750
PY2025	340,294	21,113,260	7,517,371	9,763,110	4,584,920	43,318,954	2,118,836	45,437,790
PY2026	335,883	21,368,315	7,568,475	9,791,351	4,609,744	43,673,768	2,128,652	45,802,420
PY2027	331,273	21,621,960	7,623,323	9,822,601	4,637,127	44,036,284	2,139,102	46,175,385
PY25/PY20	-1.1%	1.1%	0.8%	0.8%	0.2%	0.9%	0.3%	0 9%


National Grid RI
Residential Non-Heat Volume (Dth)
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026
2020 Forecast
2019 Forecast


National Grid RI
C&I Sales Volume (Dth)
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026
2020 Forecast
2019 Forecast


National Grid RI
Residential Heating Volume (Dth)
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026
2020 Forecast
2019 Forecast


National Grid RI
C&I FT1 and FT2 Volume (Dth)
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026
2020 Forecast
2019 Forecast

RESULTS FOR WINTER 2020/21 THROUGH WINTER 2024/25
Design Peak Hour Table

				2020/21		
Pipeline/LNG	**Lateral**	**Take Station**	**Meter No.**	**Total Supply Deliveries Company & Marketers (Dth/hr)**	**Total Firm Peak Hour Model Flow (DTH/hr)**	**Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)**
AGT	G	Barrington	00064	0	0	0
AGT	G	Warren	00012	811	756	55
AGT		Burrillville	00044	0	28	-28
AGT	G	Crary St	00842	0	3,493	-3,493
AGT	G	Dey St	00004	5,388	2,070	3,318
AGT	G	Cumberland	00083	42	49	-8
AGT	G	Portsmouth	00013	1,045	1,045	0
AGT	G	Tiverton	00033	56	65	-10
AGT	G	E Providence	00010	1,698	1,095	603
AGT	E	Westerly	00008	144	124	20
AGT		Montville	00059	208	216	-7
TGP	Cranston	Cranston	420750	3,399	2,105	1,294
TGP	Cranston	Lincoln	420758	1,283	1,310	-27
TGP	Cranston	Smithfield	420910	450	1,572	-1,122
TGP		Cumberland	420135	1,343	1,343	0
PORTABLE LNG		Portsmouth		650	106	544
LNG		Exeter		1,000	1,000	0
LNG (incl. KLNG)		Providence		3,958	3,958	0
PORTABLE LNG		Cumberland		750	750	0
			Total:	22,226	21,085	1,141

Notes

1) Flows reflect a managed system for Northern Rhode Island.

2) Flows reflect 2019 hydraulic model with a global adjustment to have demand match sendout for Capacity Exempt, FT-1 and rest of customers (SFT2) for the June 2020 forecast.

RESULTS FOR WINTER 2020/21 THROUGH WINTER
Design Peak Hour Table

				2021/22		
Pipeline/LNG	Lateral	Take Station	Meter No.	Total Supply Deliveries Company & Marketers (Dth/hr)	Total Firm Peak Hour Model Flow (DTH/hr)	Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)
AGT	G	Barrington	00064	0	0	0
AGT	G	Warren	00012	811	769	43
AGT		Burrillville	00044	0	28	-28
AGT	G	Crary St	00842	0	3,554	-3,554
AGT	G	Dey St	00004	5,401	2,112	3,289
AGT	G	Cumberland	00083	42	49	-8
AGT	G	Portsmouth	00013	1,045	1,045	0
AGT	G	Tiverton	00033	56	67	-11
AGT	G	E Providence	00010	1,698	1,180	518
AGT	E	Westerly	00008	144	125	19
AGT		Montville	00059	208	221	-13
TGP	Cranston	Cranston	420750	3,419	2,243	1,176
TGP	Cranston	Lincoln	420758	1,283	1,364	-81
TGP	Cranston	Smithfield	420910	450	1,599	-1,149
TGP		Cumberland	420135	1,343	1,343	0
PORTABLE LNG		Portsmouth		650	120	530
LNG		Exeter		1,000	1,000	0
LNG (incl. KLNG)		Providence		3,958	3,958	0
PORTABLE LNG		Cumberland		750	750	0
			Total:	22,259	21,528	731

Notes

1) Flows reflect a managed system for Northern Rhode Island.

2) Flows reflect 2019 hydraulic model with a global adjustment to have demand match sendout for Capacity Exempt, FT-1 and rest of customers (SFT2) for the June 2020 forecast.

RESULTS FOR WINTER 2020/21 THROUGH WINTEF
Design Peak Hour Table

				2022/23		
Pipeline/LNG	Lateral	Take Station	Meter No.	Total Supply Deliveries Company & Marketers (Dth/hr)	Total Firm Peak Hour Model Flow (DTH/hr)	Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)
AGT	G	Barrington	00064	0	0	0
AGT	G	Warren	00012	811	790	22
AGT		Burrillville	00044	0	29	-29
AGT	G	Crary St	00842	0	3,658	-3,658
AGT	G	Dey St	00004	5,444	2,181	3,264
AGT	G	Cumberland	00083	42	49	-8
AGT	G	Portsmouth	00013	1,045	1,045	0
AGT	G	Tiverton	00033	56	69	-13
AGT	G	E Providence	00010	1,698	1,320	378
AGT	E	Westerly	00008	144	128	16
AGT		Montville	00059	208	230	-22
TGP	Cranston	Cranston	420750	3,484	2,443	1,041
TGP	Cranston	Lincoln	420758	1,283	1,457	-173
TGP	Cranston	Smithfield	420910	450	1,641	-1,191
TGP		Cumberland	420135	1,343	1,343	0
PORTABLE LNG		Portsmouth		650	146	504
LNG		Exeter		1,000	1,000	0
LNG (incl. KLNG)		Providence		3,958	3,958	0
PORTABLE LNG		Cumberland		750	750	0
			Total:	22,367	22,237	130

Notes

1) Flows reflect a managed system for Northern Rhode Island.

2) Flows reflect 2019 hydraulic model with a global adjustment to have demand match sendout for Capacity Exempt, FT-1 and rest of customers (SFT2) for the June 2020 forecast.

RESULTS FOR WINTER 2020/21 THROUGH WINTER
Design Peak Hour Table

				2023/24		
Pipeline/LNG	**Lateral**	**Take Station**	**Meter No.**	**Total Supply Deliveries Company & Marketers (Dth/hr)**	**Total Firm Peak Hour Model Flow (DTH/hr)**	**Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)**
AGT	G	Barrington	00064	0	0	0
AGT	G	Warren	00012	770	816	-46
AGT		Burrillville	00044	0	30	-30
AGT	G	Crary St	00842	0	3,763	-3,763
AGT	G	Dey St	00004	5,474	2,242	3,232
AGT	G	Cumberland	00083	42	49	-8
AGT	G	Portsmouth	00013	1,045	1,045	0
AGT	G	Tiverton	00033	56	70	-15
AGT	G	E Providence	00010	1,698	1,457	240
AGT	E	Westerly	00008	144	130	14
AGT		Montville	00059	208	237	-29
TGP	Cranston	Cranston	420750	3,736	2,487	1,249
TGP	Cranston	Lincoln	420758	1,283	1,529	-246
TGP	Cranston	Smithfield	420910	450	1,689	-1,239
TGP		Cumberland	420135	1,343	1,343	0
PORTABLE LNG		Portsmouth		650	180	470
LNG		Exeter		1,000	1,000	0
LNG (incl. KLNG)		Providence		3,958	3,958	0
PORTABLE LNG		Cumberland		750	750	0
			Total:	22,607	22,775	-168

Notes

1) Flows reflect a managed system for Northern Rhode Island.

2) Flows reflect 2019 hydraulic model with a global adjustment to have demand match sendout for Capacity Exempt, FT-1 and rest of customers (SFT2) for the June 2020 forecast.

RESULTS FOR WINTER 2020/21 THROUGH WINTEF
Design Peak Hour Table

				2024/25		
Pipeline/LNG	**Lateral**	**Take Station**	**Meter No.**	**Total Supply Deliveries Company & Marketers (Dth/hr)**	**Total Firm Peak Hour Model Flow (DTH/hr)**	**Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)**
AGT	G	Barrington	00064	0	0	0
AGT	G	Warren	00012	770	802	-32
AGT		Burrillville	00044	0	29	-29
AGT	G	Crary St	00842	0	3,726	-3,726
AGT	G	Dey St	00004	5,461	2,229	3,233
AGT	G	Cumberland	00083	42	49	-8
AGT	G	Portsmouth	00013	1,045	1,045	0
AGT	G	Tiverton	00033	56	70	-15
AGT	G	E Providence	00010	1,698	1,413	285
AGT	E	Westerly	00008	144	129	15
AGT		Montville	00059	208	237	-29
TGP	Cranston	Cranston	420750	3,718	2,631	1,087
TGP	Cranston	Lincoln	420758	1,283	1,520	-237
TGP	Cranston	Smithfield	420910	450	1,672	-1,222
TGP		Cumberland	420135	1,343	1,343	0
PORTABLE LNG		Portsmouth		650	161	489
LNG		Exeter		1,000	1,000	0
LNG (incl. KLNG)		Providence		3,958	3,958	0
PORTABLE LNG		Cumberland		750	750	0
			Total:	22,576	22,765	-189

Notes

1) Flows reflect a managed system for Northern Rhode Island.

2) Flows reflect 2019 hydraulic model with a global adjustment to have demand match sendout for Capacity Exempt, FT-1 and rest of customers (SFT2) for the June 2020 forecast.

Exhibit 3

2020 National Grid RI Economic Data
(Prices in 2019 $/Dth)

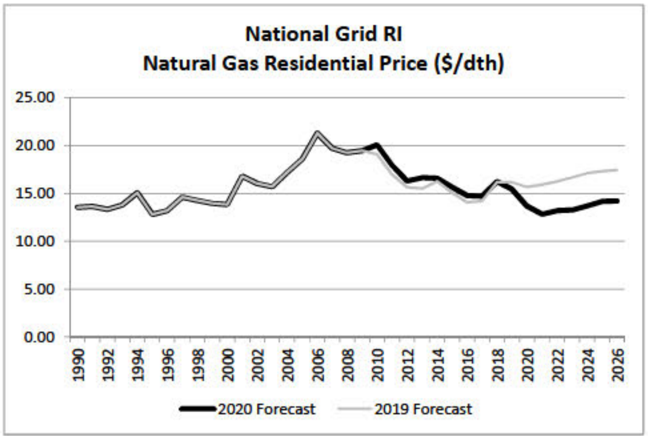
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR* *Residential Gas-to-Oil Price Ratio*	GDP GDP (2009 Millions of $)	HH Households (thousands)	EMPL Non-Farm Employment (thousands)
1990	*13.50*	*14.60*	*0.92*	*35616*	*377*	*454*
1991	*13.62*	*13.32*	*1.02*	*34372*	*381*	*424*
1992	*13.33*	*11.69*	*1.14*	*35063*	*384*	*424*
1993	*13.77*	*11.20*	*1.23*	*35716*	*387*	*430*
1994	*15.06*	*10.61*	*1.42*	*35826*	*391*	*434*
1995	*12.79*	*10.30*	*1.24*	*36505*	*395*	*439*
1996	*13.18*	*11.25*	*1.17*	*36926*	*401*	*441*
1997	*14.58*	*11.19*	*1.30*	*38989*	*406*	*450*
1998	*14.24*	*9.70*	*1.47*	*40360*	*411*	*458*
1999	*13.96*	*9.05*	*1.54*	*41651*	*411*	*466*
2000	*13.82*	*12.91*	*1.07*	43474	410	477
2001	*16.81*	*12.61*	*1.33*	44386	407	479
2002	*16.03*	*11.17*	*1.43*	45877	410	479
2003	*15.68*	*13.33*	*1.18*	47804	411	484
2004	*17.18*	*14.12*	*1.22*	49762	412	488
2005	*18.56*	*18.01*	*1.03*	50378	411	491
2006	*21.29*	*21.17*	*1.01*	51304	411	493
2007	*19.70*	*22.08*	*0.89*	49843	411	492
2008	*19.25*	*27.64*	*0.70*	48263	414	481
2009	*19.45*	*19.50*	*1.00*	47708	414	459
2010	20.06	25.04	*0.80*	51466	415	458
2011	17.92	31.03	*0.58*	51270	417	461
2012	16.28	33.04	*0.49*	51641	421	465
2013	16.62	32.45	*0.51*	52085	425	471
2014	16.57	31.26	*0.53*	52133	428	479
2015	15.61	21.83	*0.72*	53095	428	485
2016	14.74	17.32	*0.85*	53091	427	490
2017	14.69	19.96	*0.74*	52989	426	493
2018	16.23	22.12	*0.73*	53622	426	496
2019	15.42	21.07	*0.73*	54464	429	501
2020	13.64	17.38	*0.78*	53470	431	495
2021	12 82	17.73	*0.72*	54933	432	496
2022	13.19	18.32	*0.72*	57588	434	506
2023	13 26	18.73	*0.71*	59640	436	513
2024	13.68	19.34	*0.71*	61109	438	515
2025	14.13	19.75	*0.72*	62449	440	517
2026	14.19	20.08	*0.71*	63820	442	519
2027	14 30	20.14	*0.71*	65280	443	520
PY25/PY20	-0.02	-0.02	-0.01	2.3%	0.4%	0.5%

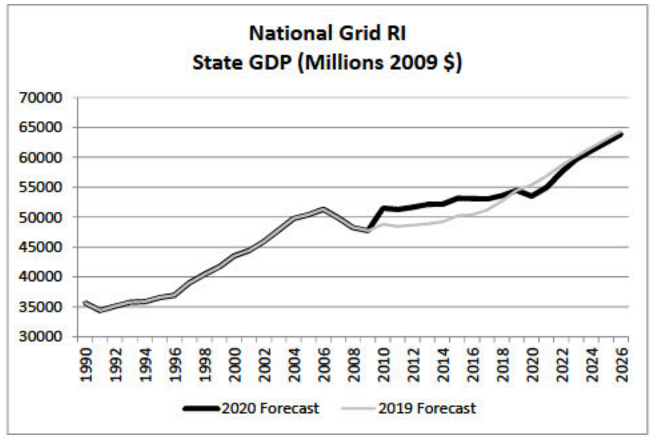
Exhibit 3

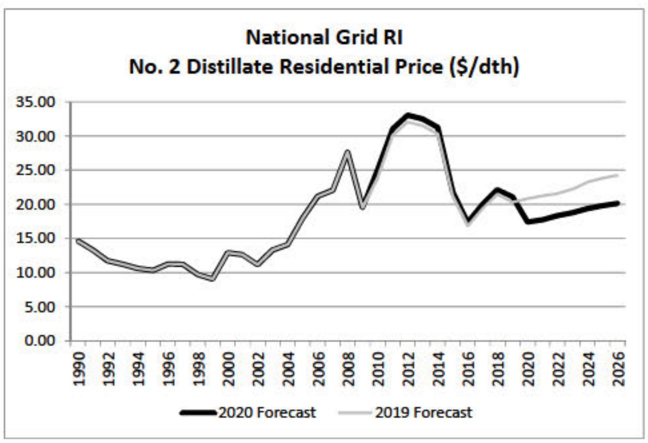
2019 National Grid RI Economic Data
(Prices in 2019 $/Dth)

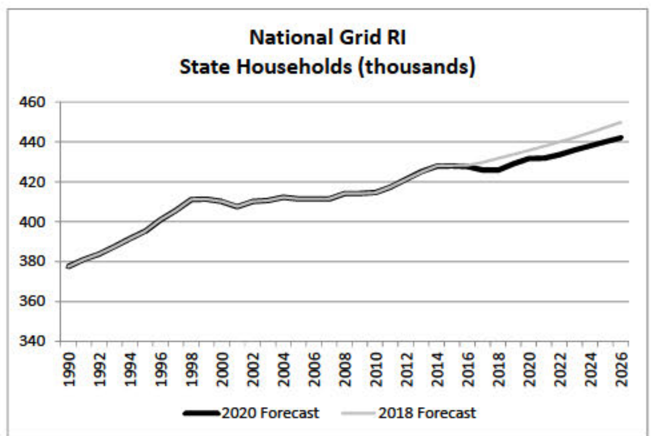
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR*	GDP (2005 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	13.50	14.60	*0.92*	35616	377	454
1991	13.62	13.32	*1.02*	34372	381	424
1992	13.33	11.69	*1.14*	35063	384	424
1993	13.77	11.20	*1.23*	35716	387	430
1994	15.06	10.61	*1.42*	35826	391	434
1995	12.79	10.30	*1.24*	36505	395	439
1996	13.18	11.25	*1.17*	36926	401	441
1997	14.58	11.19	*1.30*	38989	406	450
1998	14.24	9.70	*1.47*	40360	411	458
1999	13.96	9.05	*1.54*	41651	411	466
2000	13.82	12.91	*1.07*	43476	410	477
2001	16.81	12.61	*1.33*	44388	407	479
2002	16.03	11.17	*1.43*	45881	410	479
2003	15.68	13.33	*1.18*	47804	411	484
2004	17.18	14.12	*1.22*	49763	412	488
2005	18.56	18.01	*1.03*	50380	411	491
2006	21.29	21.17	*1.01*	51304	411	493
2007	19.70	22.08	*0.89*	49838	411	492
2008	19.25	27.64	*0.70*	48262	414	481
2009	19.45	19.50	*1.00*	47709	414	459
2010	19.07	23.82	*0.80*	48801	414	458
2011	16.97	30.08	*0.56*	48425	417	461
2012	15.62	32.03	*0.49*	48630	421	465
2013	15.48	31.46	*0.49*	48815	425	472
2014	16.24	30.31	*0.54*	49217	428	479
2015	15.04	21.17	*0.71*	50174	428	485
2016	14.05	16.80	*0.84*	50406	427	490
2017	14.18	19.36	*0.73*	51192	426	494
2018	16.16	21.44	*0.75*	52719	422	501
2019	16.17	20.28	*0.80*	54456	424	507
2020	15.66	20.82	*0.75*	55401	426	510
2021	15.90	21.24	*0.75*	56891	428	509
2022	16.23	21.56	*0.75*	58647	429	512
2023	16.65	22.20	*0.75*	60158	431	515
2024	17.11	23.23	*0.74*	61647	432	518
2025	17.29	23.81	*0.73*	63013	434	520
2026	17.42	24.21	*0.72*	64358	435	522
2027	17 50	24.86	*0.70*	65762	436	524
PY24/PY19	0.01	0.03	-0.02	2.5%	0.4%	0.4%

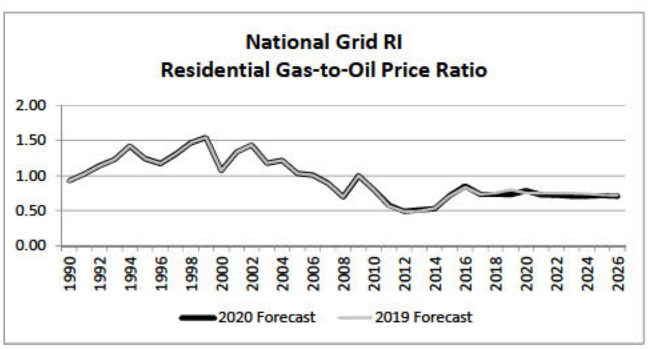
Exhibit 3

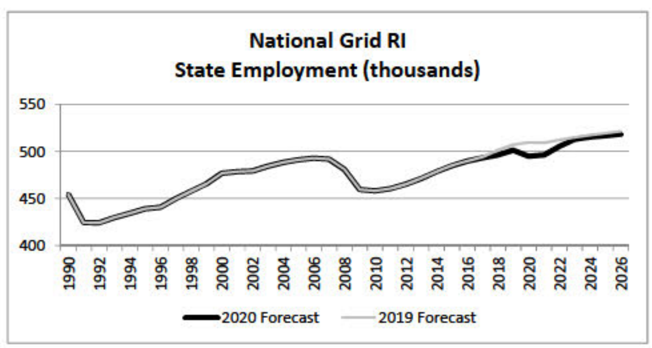

National Grid RI
Natural Gas Residential Price ($/dth)
2020 Forecast
2019 Forecast


National Grid RI
State GDP (Millions 2009 $)
2020 Forecast
2019 Forecast

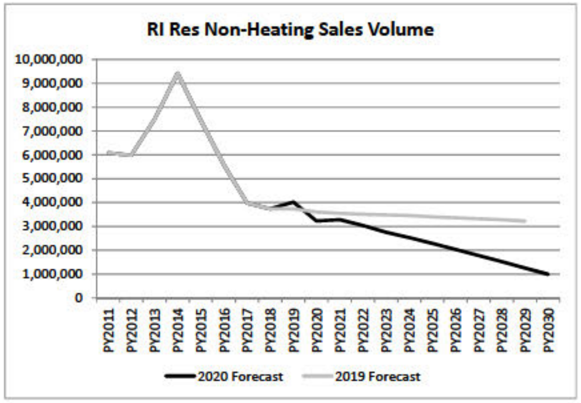

National Grid RI
No. 2 Distillate Residential Price ($/dth)
2020 Forecast
2019 Forecast

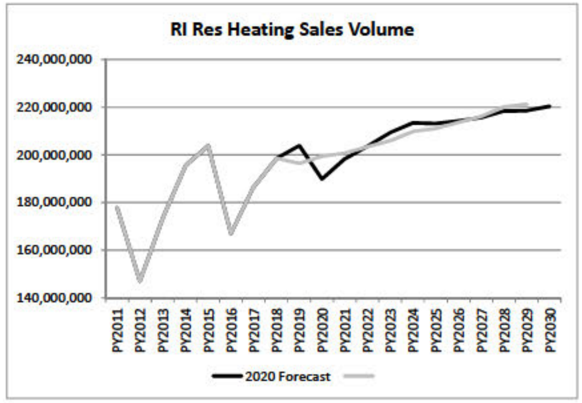

National Grid RI
State Households (thousands)
2020 Forecast
2018 Forecast

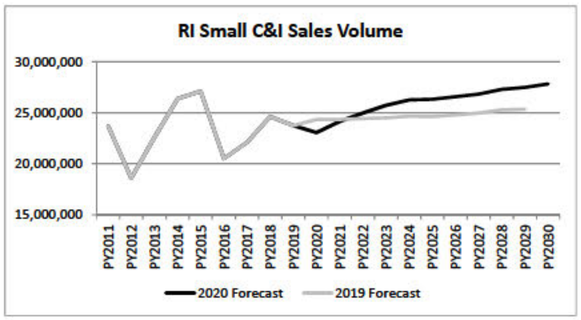

National Grid RI
Residential Gas-to-Oil Price Ratio
2020 Forecast
2019 Forecast

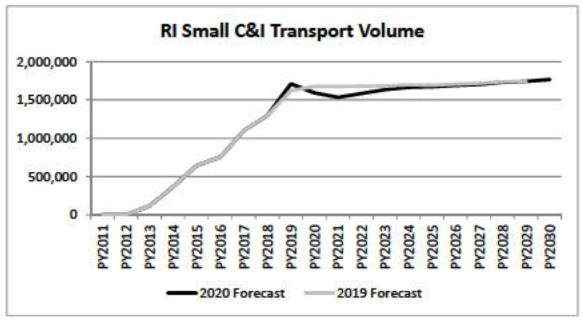

National Grid RI
State Employment (thousands)
2020 Forecast
2019 Forecast

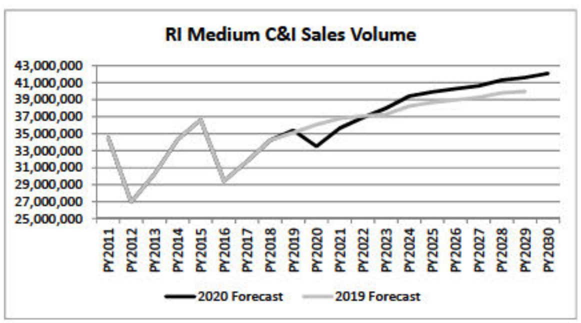
2020 and 2019 Volume Forecasts by Rate Class
(Therms; Planning Year)

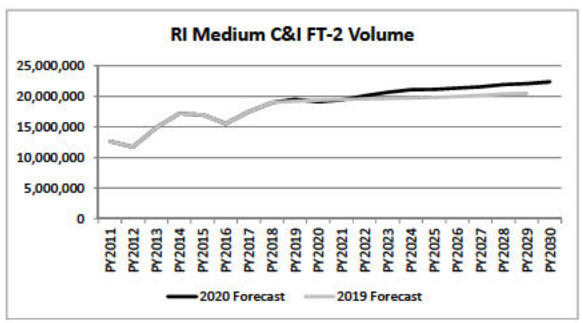


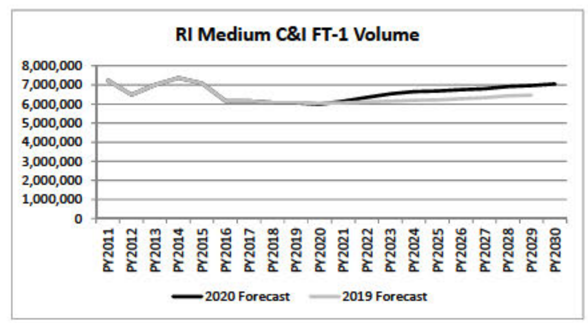




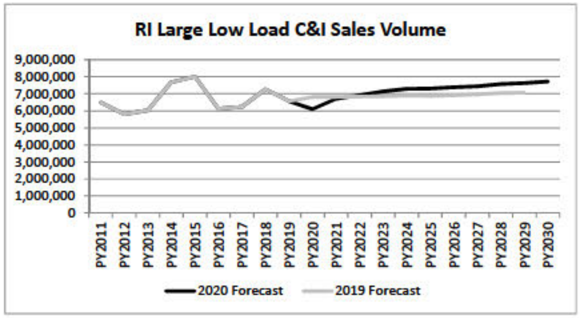


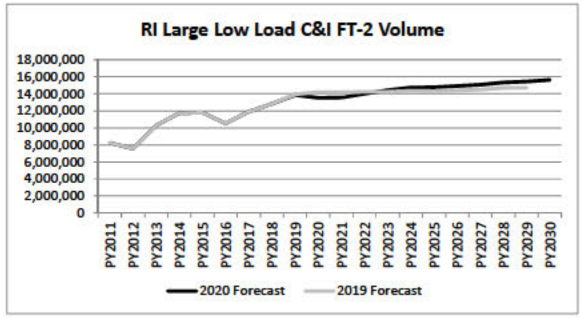


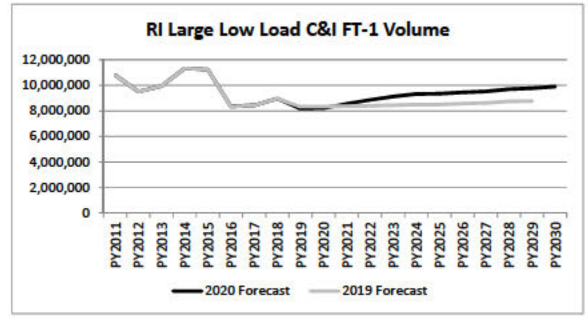


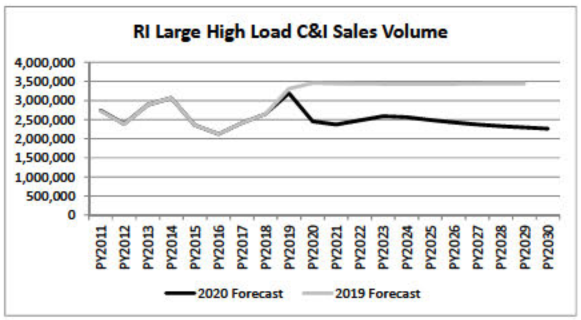


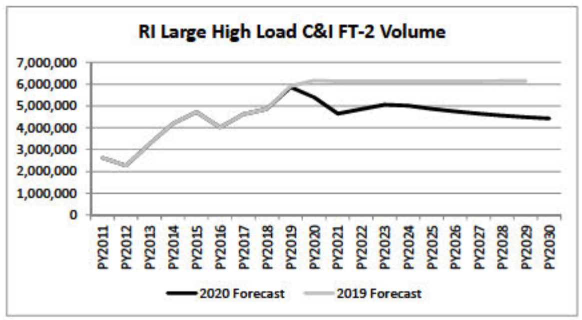
2020 and 2019 Volume Forecasts by Rate Class
(Therms; Planning Year)

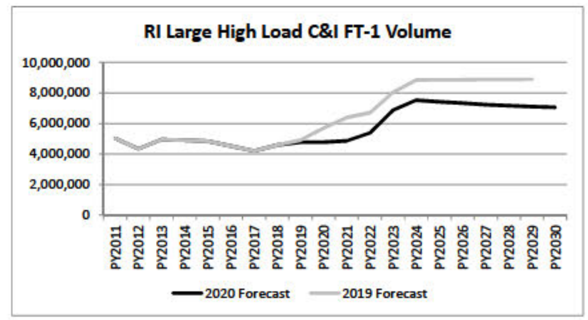


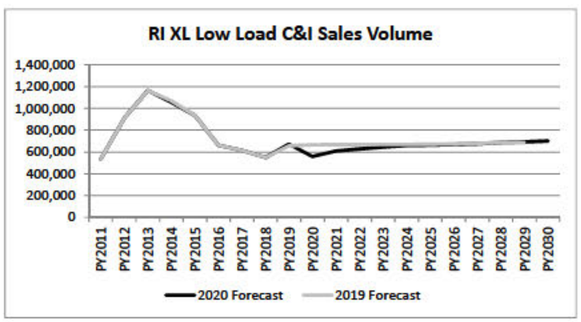


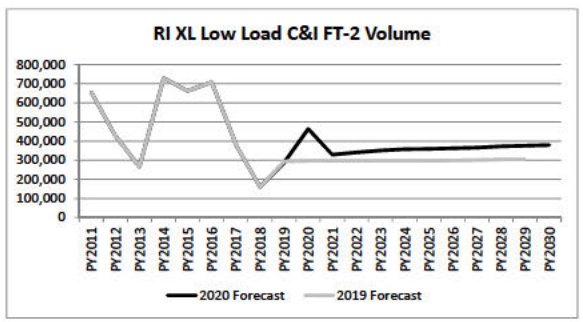


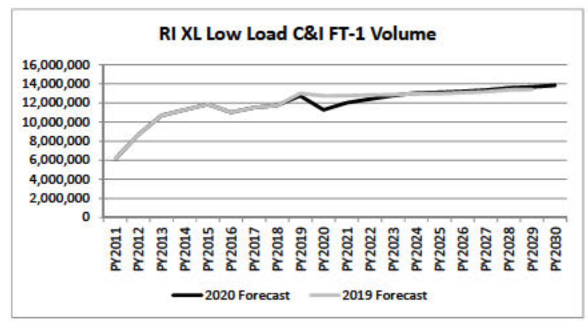




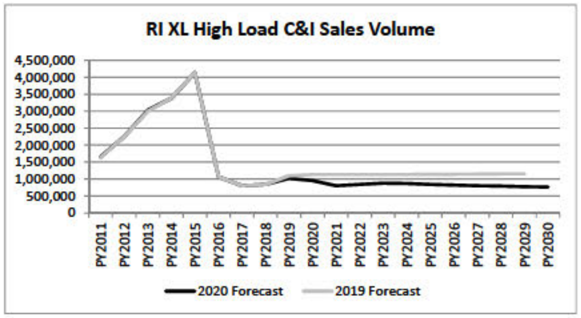


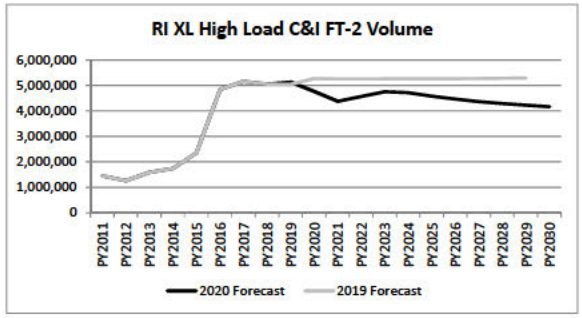


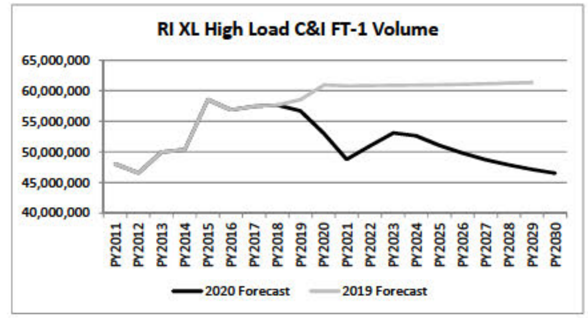


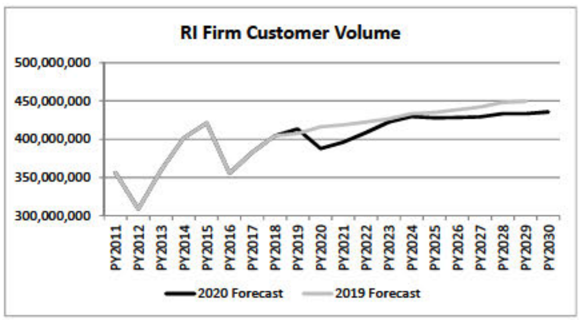


2020 and 2019 Volume Forecasts by Rate Class
(Therms; Planning Year)







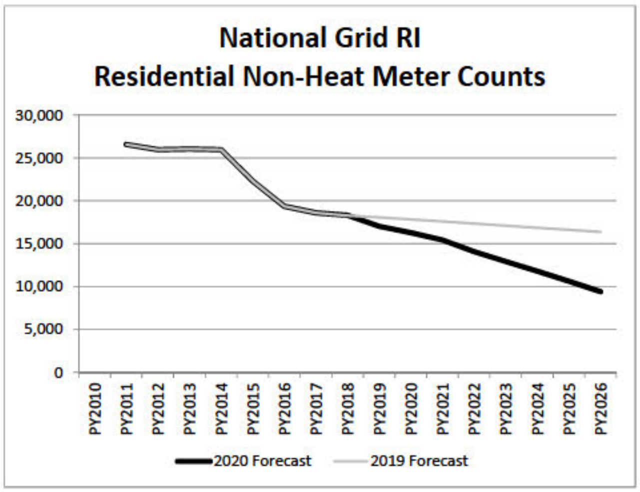


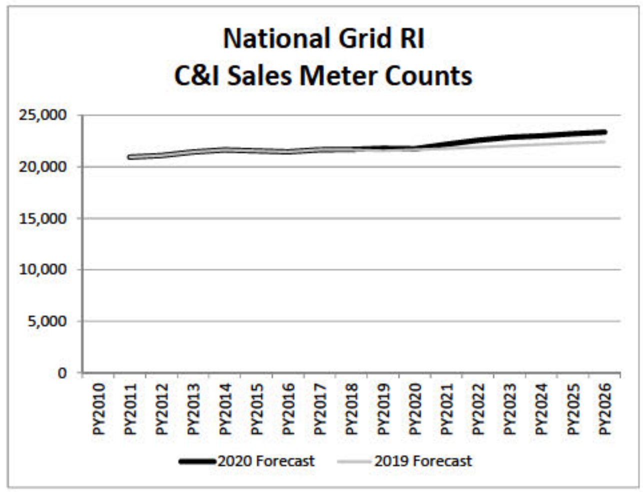
2020 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

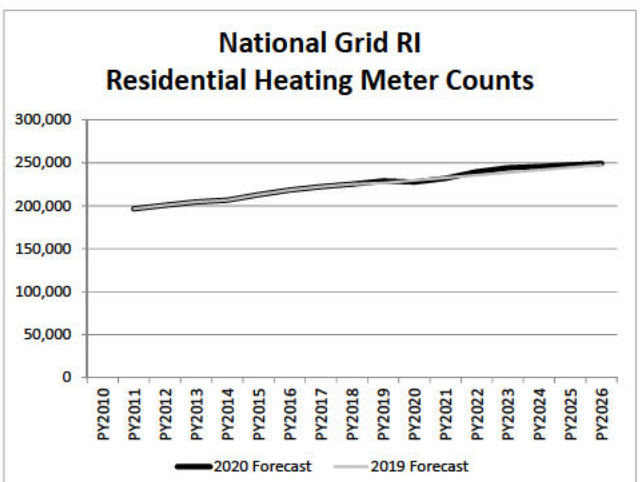
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,950	747	1,244	245,925	54	245,979
PY2012	25,955	200,463	21,105	734	1,399	249,656	65	249,721
PY2013	26,042	204,521	21,451	721	1,499	254,234	159	254,393
PY2014	25,958	206,568	21,651	699	1,486	256,362	178	256,540
PY2015	22,313	212,900	21,567	684	1,552	259,016	326	259,342
PY2016	19,351	218,313	21,467	674	1,680	261,485	488	261,973
PY2017	18,590	222,122	21,672	636	1,758	264,778	577	265,355
PY2018	18,304	225,228	21,702	624	1,776	267,634	637	268,271
PY2019	17,012	228,896	21,804	609	1,888	270,209	816	271,025
PY2020	16,272	227,624	21,758	588	1,861	268,103	845	268,948
PY2021	15,436	231,871	22,202	603	1,899	272,011	862	272,873
PY2022	14,078	239,512	22,592	616	1,936	278,734	877	279,611
PY2023	12,912	244,122	22,881	629	1,964	282,508	887	283,395
PY2024	11,787	245,713	23,024	636	1,976	283,136	893	284,029
PY2025	10,613	247,442	23,223	641	1,991	283,910	900	284,810
PY2026	9,396	249,132	23,379	643	2,005	284,555	906	285,461
PY2027	8,125	250,853	23,565	649	2,021	285,213	914	286,127
PY24/PY19	-8.2%	1.7%	1.3%	1.7%	1.4%	1.2%	1.3%	1.2%

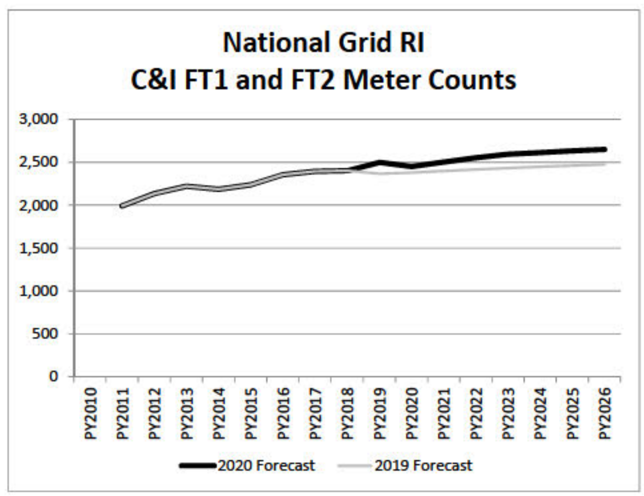
2019 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,950	747	1,244	245,925	54	245,979
PY2012	25,955	200,463	21,105	734	1,399	249,656	65	249,721
PY2013	26,042	204,520	21,451	721	1,499	254,233	159	254,392
PY2014	25,958	206,567	21,650	699	1,486	256,360	178	256,538
PY2015	22,313	212,899	21,565	684	1,552	259,013	326	259,339
PY2016	19,351	218,312	21,465	674	1,680	261,482	488	261,970
PY2017	18,589	222,114	21,666	636	1,758	264,763	577	265,340
PY2018	18,280	225,136	21,676	624	1,776	267,492	637	268,129
PY2019	18,059	226,499	21,555	601	1,765	268,479	741	269,220
PY2020	17,816	229,543	21,662	606	1,773	271,400	745	272,145
PY2021	17,574	232,610	21,780	613	1,784	274,361	748	275,109
PY2022	17,332	235,549	21,917	619	1,796	277,213	753	277,966
PY2023	17,090	238,549	22,049	624	1,807	280,119	757	280,876
PY2024	16,847	241,525	22,181	630	1,818	283,001	761	283,762
PY2025	16,605	244,499	22,310	633	1,828	285,875	766	286,641
PY2026	16,363	247,462	22,430	635	1,838	288,728	770	289,498
PY2027	16,120	250,404	22,546	639	1,849	291,558	774	292,332
PY25/PY20	-1.4%	1 3%	0.6%	0 9%	0.6%	1.0%	0.6%	1.0%

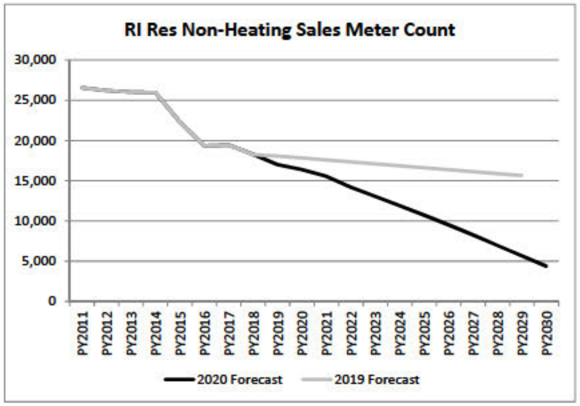

National Grid RI
Residential Non-Heat Meter Counts
30,000
25,000
20,000
15,000
10,000
5,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2020 Forecast
2019 Forecast

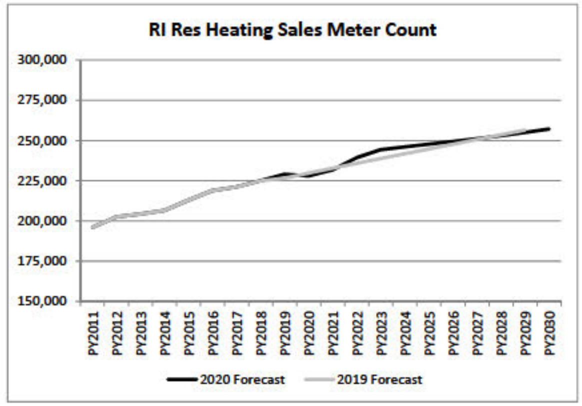

National Grid RI
C&I Sales Meter Counts
25,000
20,000
15,000
10,000
5,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2020 Forecast
2019 Forecast

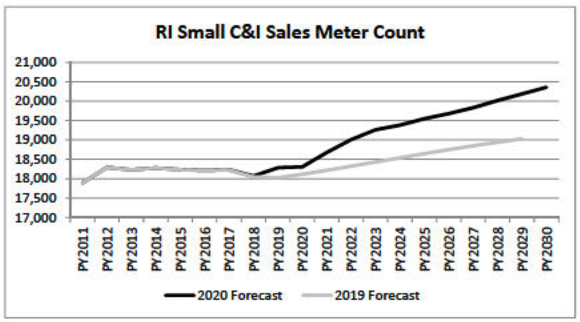

National Grid RI
Residential Heating Meter Counts
300,000
250,000
200,000
150,000
100,000
50,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2020 Forecast
2019 Forecast

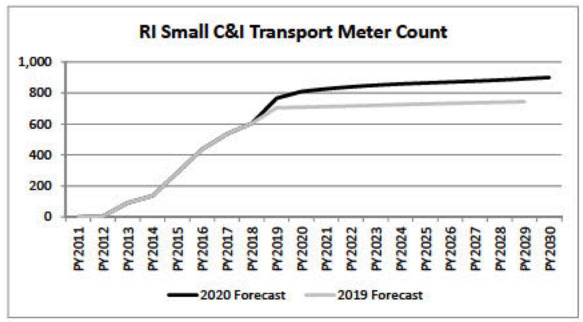

National Grid RI
C&I FT1 and FT2 Meter Counts
3,000
2,500
2,000
1,500
1,000
500
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2020 Forecast
2019 Forecast

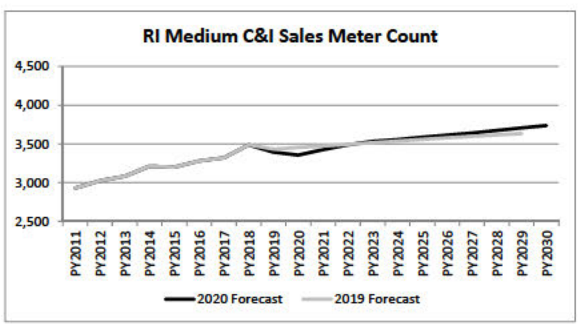
2020 and 2019 Meter Count Forecasts by Rate Class
(end of Planning Year)

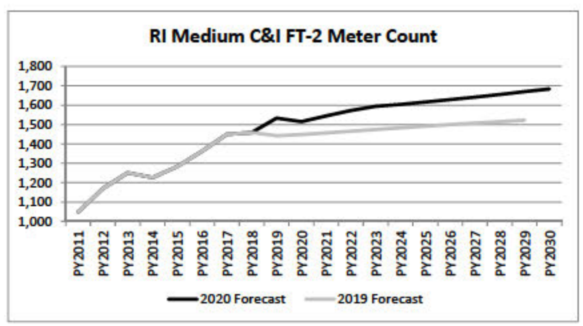


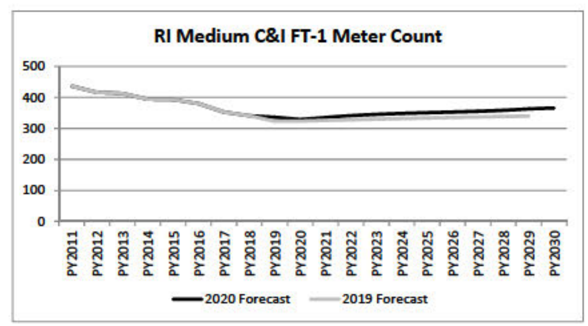




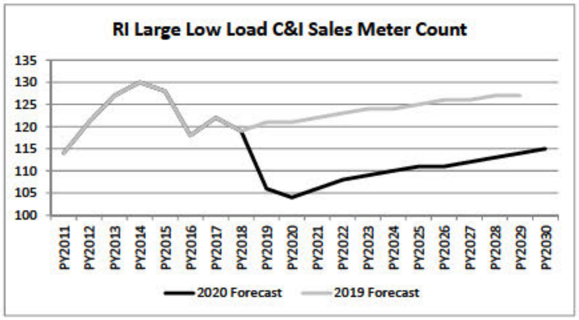


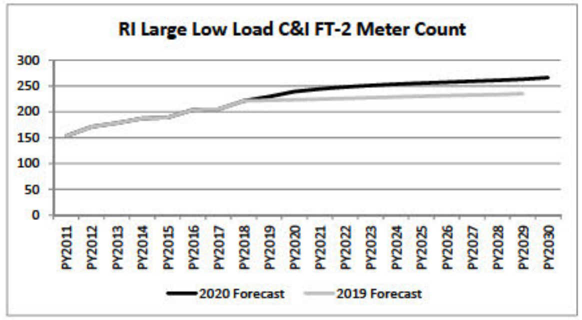


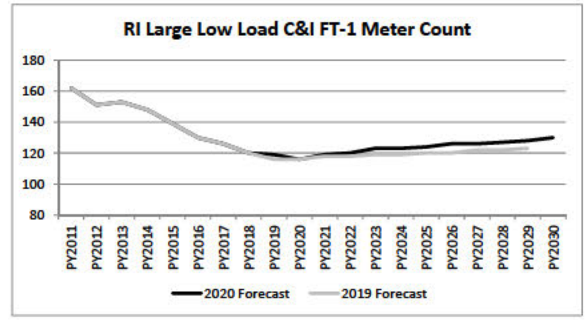


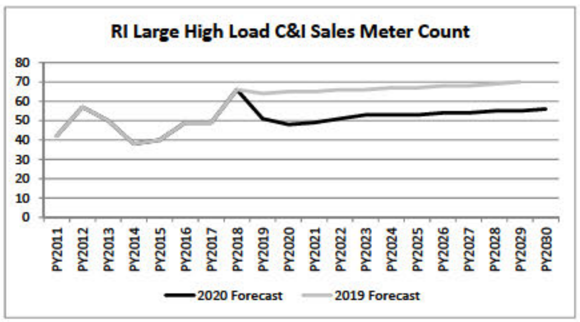


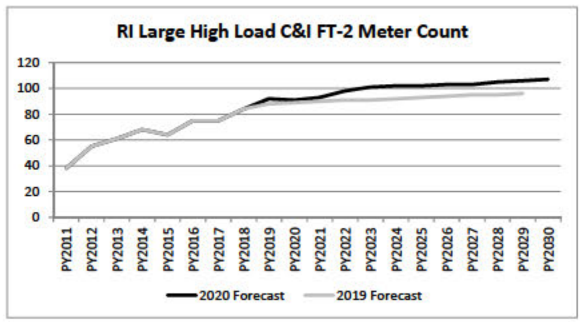
2020 and 2019 Meter Count Forecasts by Rate Class
(end of Planning Year)

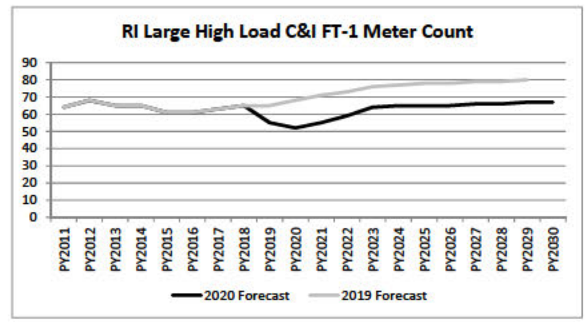


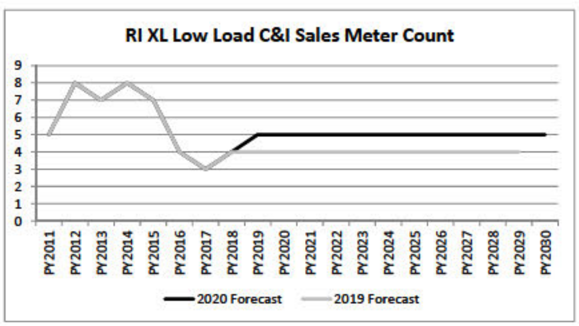


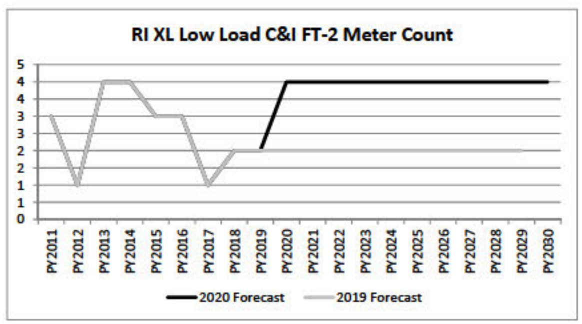


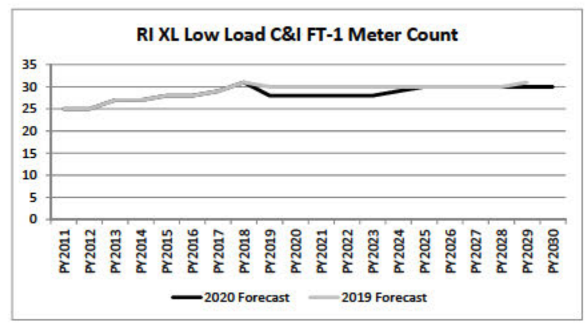




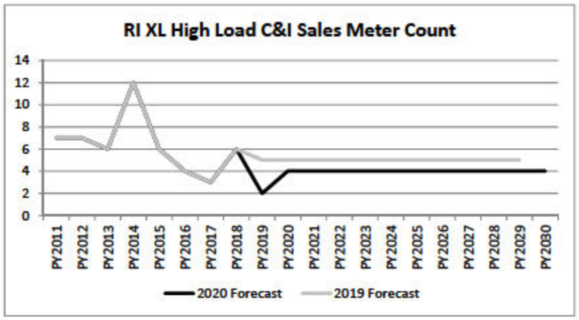


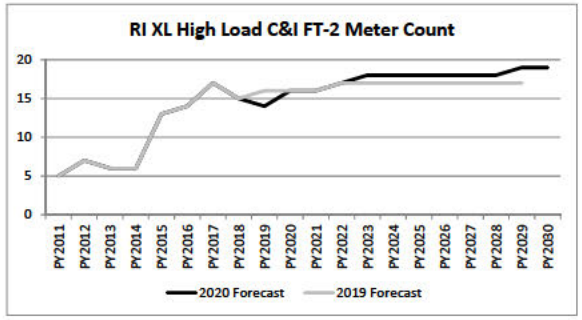


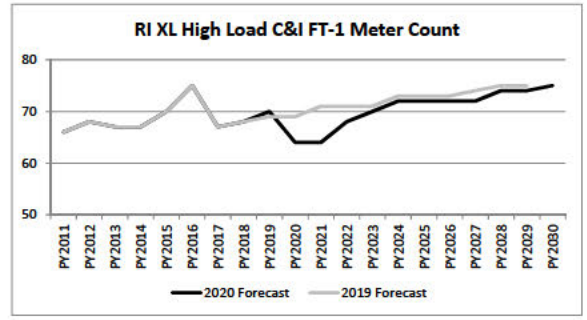


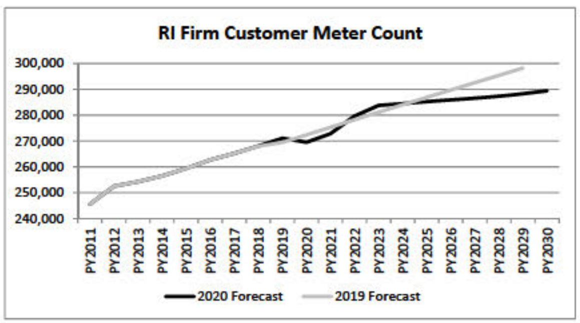


2020 and 2019 Meter Count Forecasts by Rate Class
(end of Planning Year)









Please see the attached excel document for the Company Wholesale Forecast by Rate.

The Narragansett Electric Company -Take Station Contract Quantities (MMBtu)

* = Peak MDQ
^ = Not incremental city gate capacity

ALGONQUIN	9001	90106	* 90107	933005	* 93001ESC	* 93011E	93401S	96004SC	* 9B105	* 9S100S	* 9W009E	510801	Constellation CG Supply NSB19_ 24-42-20	^ 510985	Total
1/24th or 6% Hourly:	1/24th	1/24th	6%	1/24th	6%	6%	1/24th	1/24th	1/24th	1/24th	6%	1/24th	1/24th	1/24th	
Contract MDTQ:	11,063	19,465	26,129	2,061	2,384	56,035	335	1,695	8,539	187	6,812	18,000	14,100	96,000	166,805
Dey St. (#00004)	11,063	9,223	19,514	---	---	25,137	---	---	4,258	---	6,234	---	13,100	---	88,529
Westerly (#00008)	---	474	---	248	---	1,221	---	---	79	---	273	500	---	---	2,795
Wampanoag Trail [E. Prov] (#00010)	---	4,092	6,615	---	---	*18,837*	---	---	---	---	---	---	---	---	29,544
Portsmouth (#00013)	---	5,078	---	---	---	6,504	---	---	4,202	---	305	6,000	---	---	22,089
Tiverton (#00033)	---	598	---	---	---	163	---	---	---	---	---	500	---	---	1,261
Burrillville (#00044)	---	---	---	---	---	---	---	---	---	---	---	---	---	---	0
Barrington (#00064)	---	---	---	---	---	---	---	---	---	---	---	---	---	---	0
Bristol/Warren (#00012)	---	---	---	813	2,384	4,173	335	1,695	---	187	---	6,000	1,000	---	16,587
Cumberland (#00083)	---	---	---	1,000	---	---	---	---	---	---	---	---	---	---	1,000
Crary St. (#00842)	---	---	---	---	---	---	---	---	---	---	---	---	---	96,000	96,000
Montville (#00059)[Yankee Gas]	---	---	---	---	---	---	---	---	---	---	---	5,000	---	---	5,000

Take Station Total: 262,805

ALGONQUIN	9001	90106	90107	933005	93001ESC	93011E	93401S	96004SC	9B105	9S100S	9W009E	510801	Constellation CG Supply NSB19_ 24-42-20	510985	Total
1/24th or 6% Hourly:	1/24th	1/24th	6%	1/24th	6%	6%	1/24th	1/24th	1/24th	1/24th	6%	1/24th	1/24th	1/24th	
Contract MDTQ:	461	811	1,568	86	143	3,362	14	71	356	8	409	750	588	4,000	8,625
Dey St. (#00004)	461	384	1,171	---	---	1,508	---	---	177	---	374	---	546	---	4,622
Westerly (#00008)	---	20	---	10	---	73	---	---	3	---	16	21	---	---	144
Wampanoag Trail [E. Prov] (#00010)	---	171	397	---	---	1,130	---	---	---	---	---	---	---	---	1,698
Portsmouth (#00013)	---	212	---	---	---	390	---	---	175	---	18	250	---	---	1,045
Tiverton (#00033)	---	25	---	---	---	10	---	---	---	---	---	21	---	---	56
Burrillville (#00044)	---	---	---	---	---	---	---	---	---	---	---	---	---	---	0
Barrington (#00064)	---	---	---	---	---	---	---	---	---	---	---	---	---	---	0
Bristol/Warren (#00012)	---	---	---	34	143	250	14	71	---	8	---	250	42	---	811
Cumberland (#00083)	---	---	---	42	---	---	---	---	---	---	---	---	---	---	42
Crary St. (#00842)	---	---	---	---	---	---	---	---	---	---	---	---	---	4,000	4,000
Montville (#00059)[Yankee Gas]	---	---	---	---	---	---	---	---	---	---	---	208	---	---	208

Take Station Total: 12,625

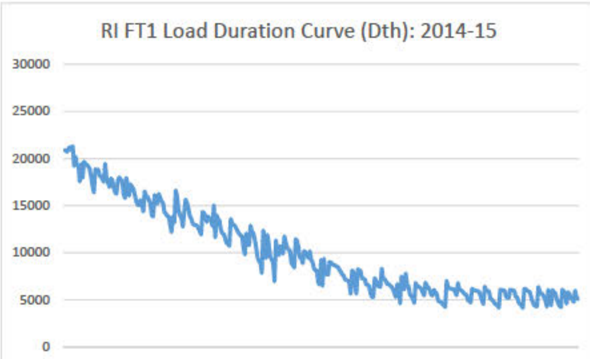
TENNESSEE	10807	95345	39173	62930	1597	64025	64026	330580	330581	349449	Total
All 1/24th:	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	
Contract MDTQ:	10,836	1,000	1,067	15,000	29,335	5,220	6,380	24,000	15,000	20,000	127,838
Cranston (#420750)	---	---	---	9,000	10,000	---	---	---	15,000	20,000	54,000
Smithfield (#420910)	---	---	---	---	5,000	2,610	3,190	---	---	---	10,800
Pawtucket (#420135)	10,836	---	1,067	6,000	14,335	---	---	---	---	---	32,238
Lincoln (#420758)	---	1,000	---	---	---	2,610	3,190	24,000	---	---	30,800

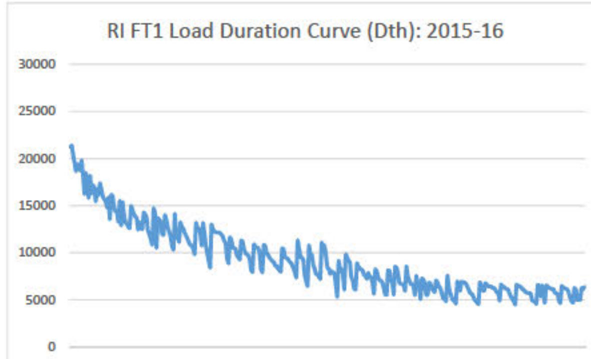
Take Station Total: 127,838

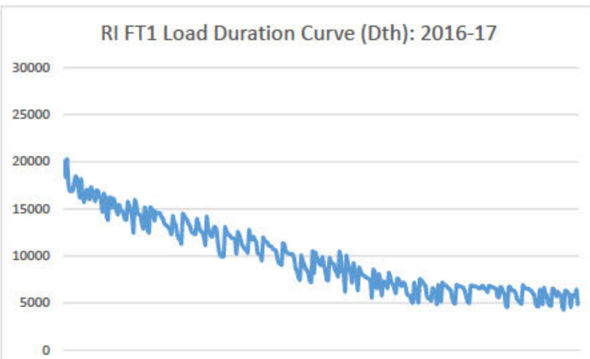
TENNESSEE	10807	95345	39173	62930	1597	64025	64026	330580	330581	349449	Total
All 1/24th:	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	1/24th	
Contract MDTQ:	452	42	44	625	1,222	218	266	1,000	625	833	5,327
Cranston (#420750)	---	---	---	375	417	---	---	---	625	833	2,250
Smithfield (#420910)	---	---	---	---	208	109	133	---	---	---	450
Pawtucket (#420135)	452	---	44	250	597	---	---	---	---	---	1,343
Lincoln (#420758)	---	42	---	---	---	109	133	1,000	---	---	1,283

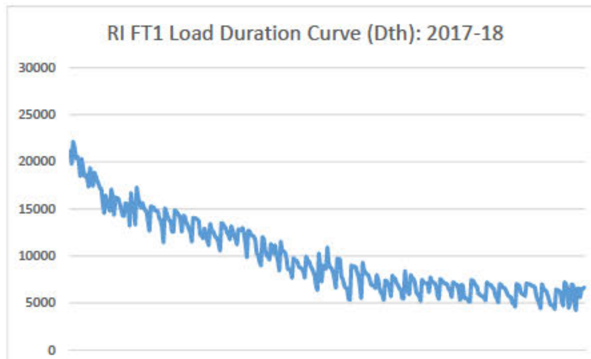
Take Station Total: 5,327

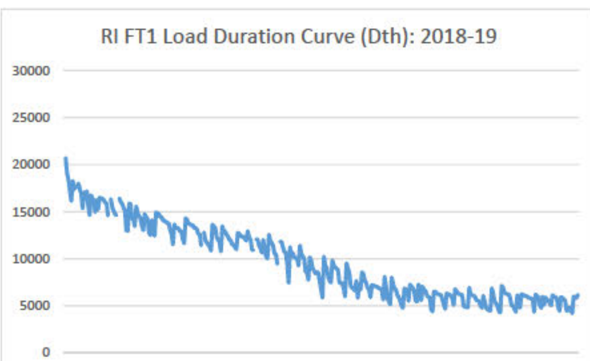
Load Duration Curves for FT1 Customers
Historical Actuals and Forecasted Design Weather

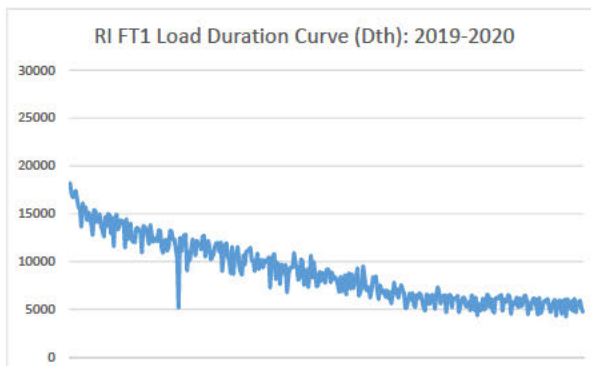




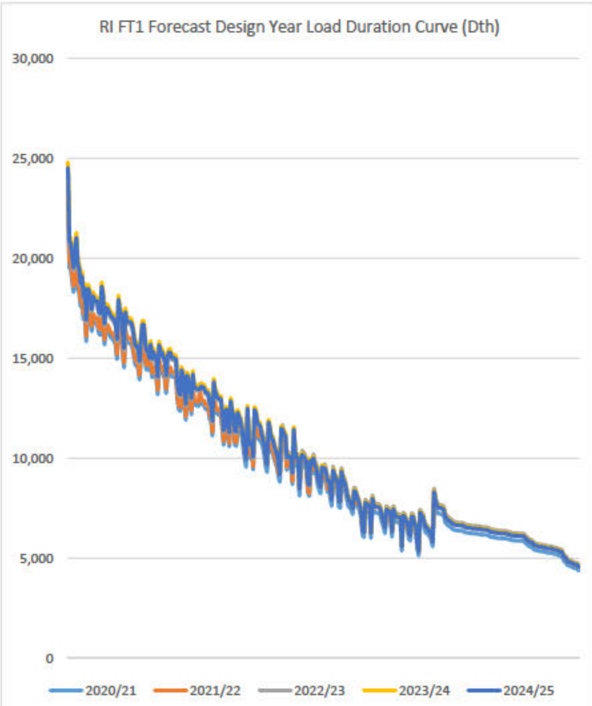




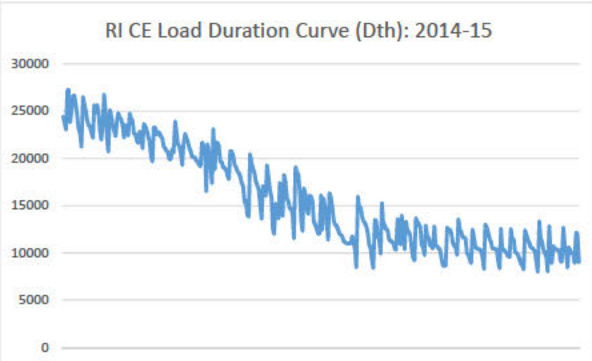


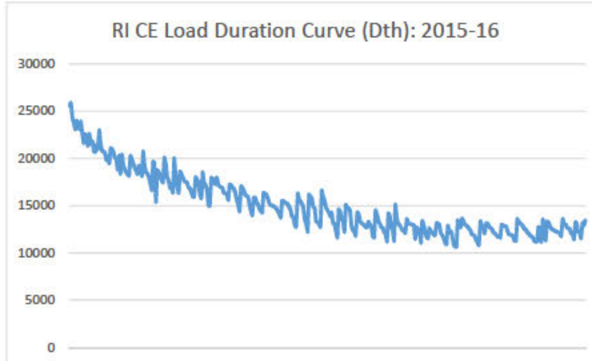


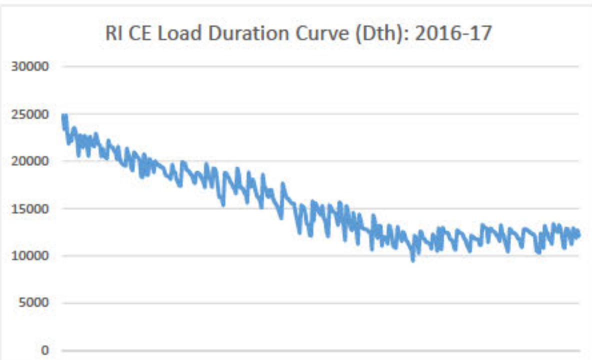
Load Duration Curves for FT1 Customers
Historical Actuals and Forecasted Design Weather

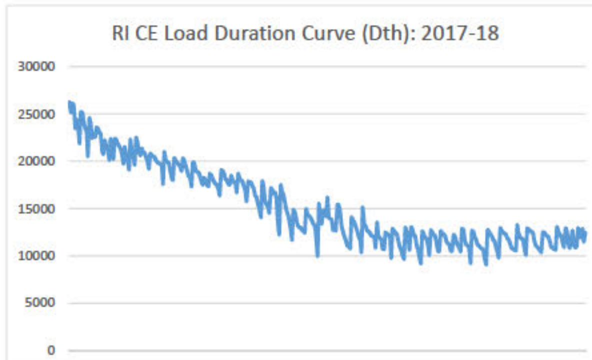


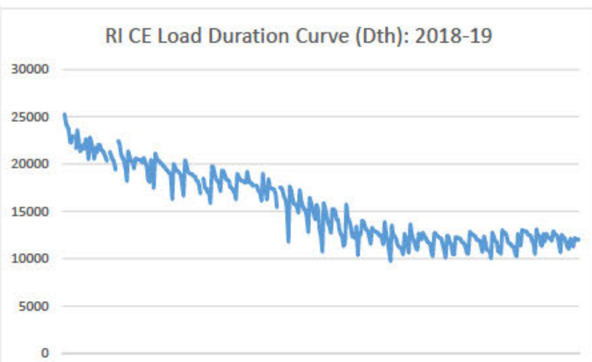
Load Duration Curves for Capacity Exempt Customers
Historical Actuals and Forecasted Design Weather

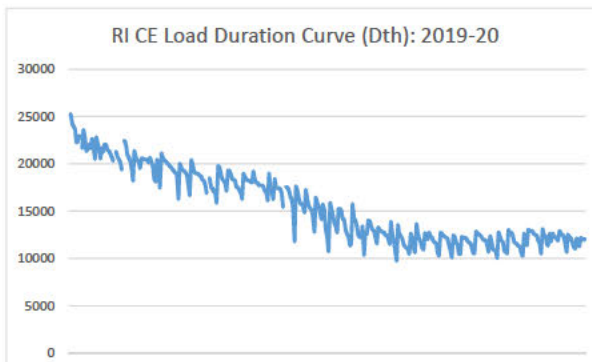




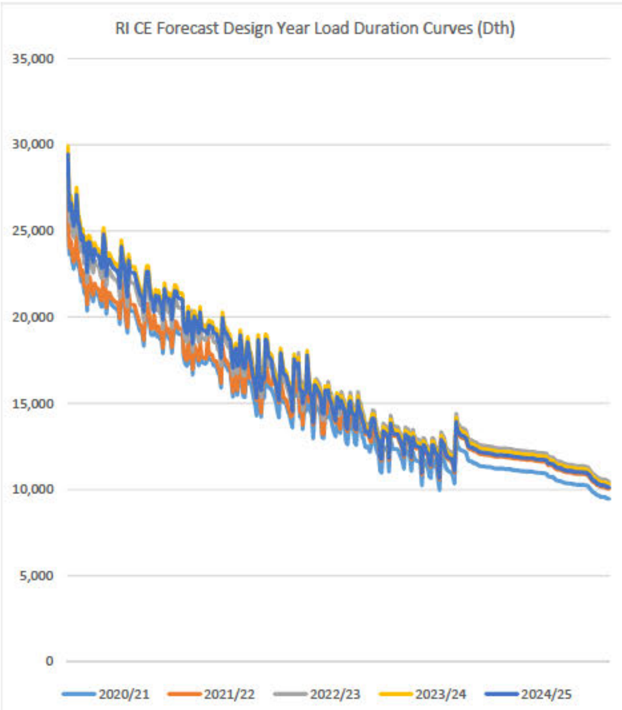




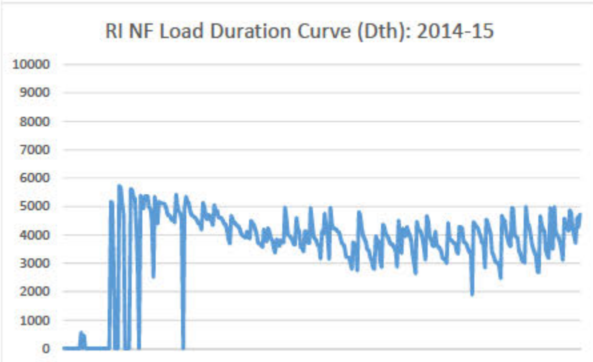


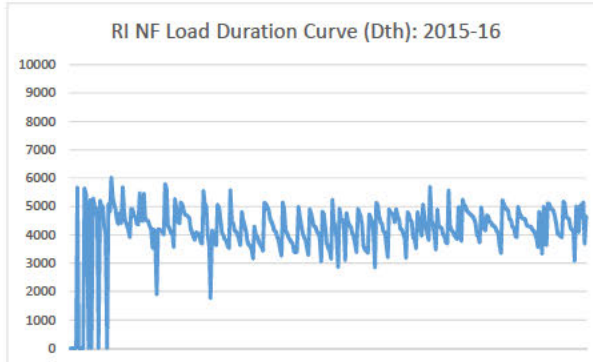


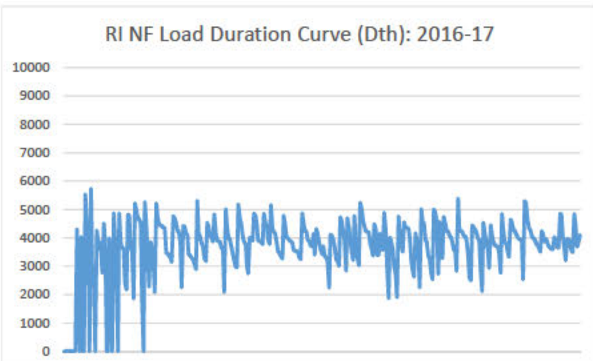
Load Duration Curves for Capacity Exempt Customers
Historical Actuals and Forecasted Design Weather

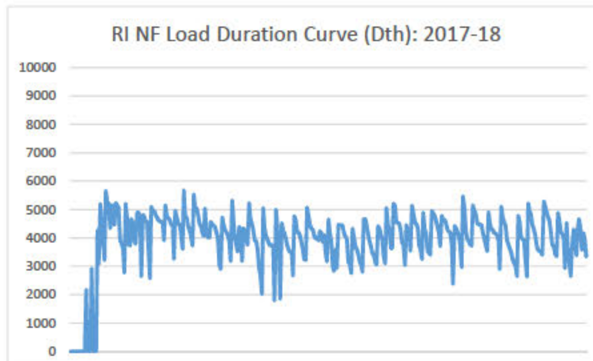


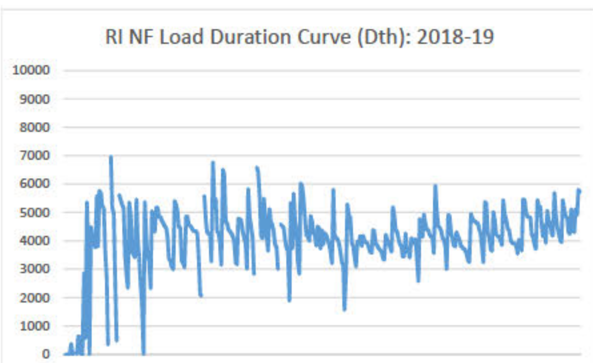
Load Duration Curves for Non-Firm Customers
Historical Actuals and Forecasted Design Weather

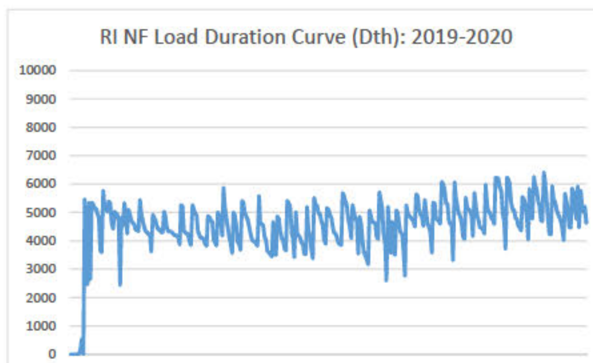












Load Duration Curves for Non-Firm Customers
Historical Actuals and Forecasted Design Weather

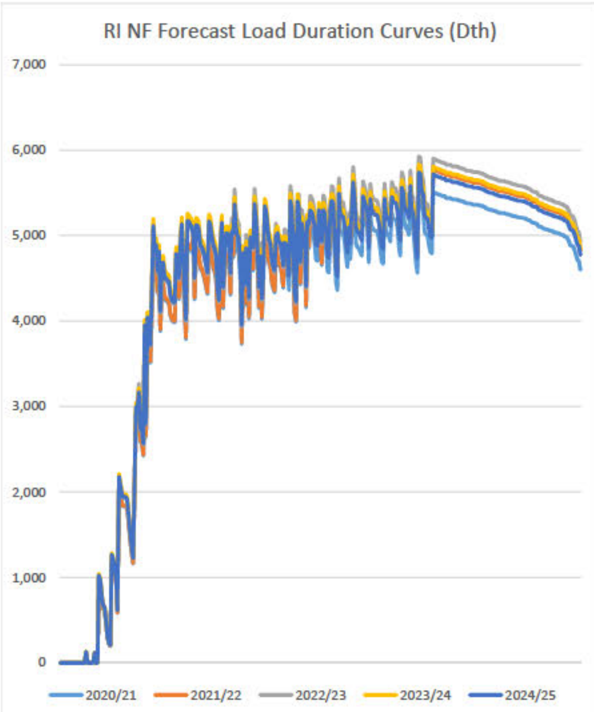
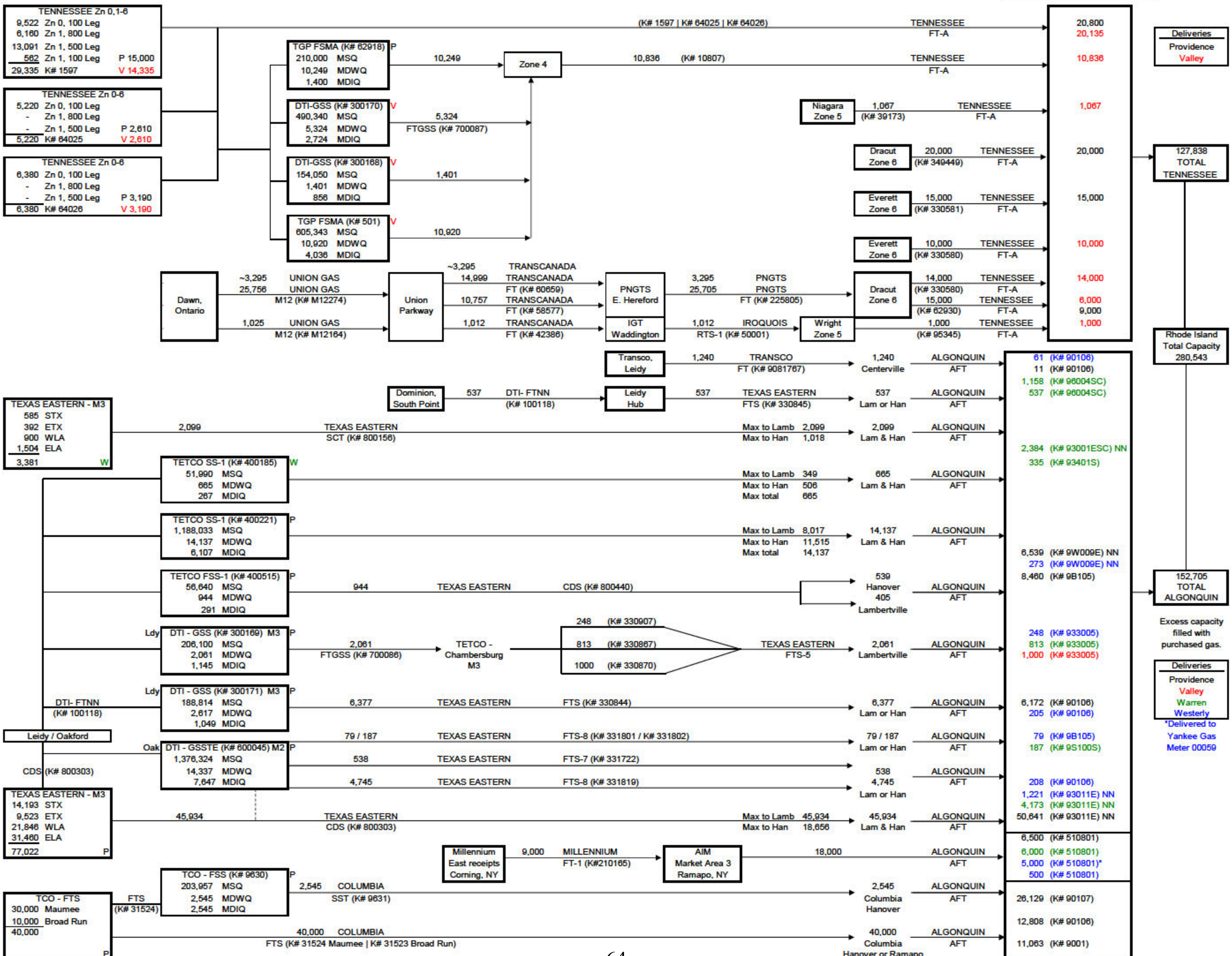


Exhibit 12

RHODE ISLAND COMPANIES - CONSOLIDATED PORTFOLIO SCHEMATIC

Peak Season Volumes

As of November 1, 2020



NATIONAL GRID - RHODE ISLAND ASSETS
Transportation Contracts

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
Narragansett Electric Co.	Algonquin	9001	AFT1FT3	11,063	4,037,995	12/31/2021	No	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).
Narragansett Electric Co.	Algonquin	90106	AFT-14	19,465	7,104,725	10/31/2021	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).
Narragansett Electric Co.	Algonquin	90107	AFT-1W	26,129	3,945,479	10/31/2021	Yes	Part-284 service with a seasonally adjusted MDQ of (26,129 MMBtu), used to transport gas from Ramapo, NY (7,455 MMBtu) or the Columbia interconnect at Hanover (18,674 MMBtu), NJ to National Grid - Dey St (19,514 MMBtu) and National Grid - E. Providence (6,615 MMBtu).
Narragansett Electric Co.	Algonquin	933005	AFT-1P	2,061	752,265	3/31/2021	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), National Grid - Westerly (248 MMBtu), and National Grid - Warren (813 MMBtu).
Narragansett Electric Co.	Algonquin	93001ESC	AFT-ES1	2,384	771,904	10/31/2021	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).
Narragansett Electric Co.	Algonquin	93011E	AFT-E1	56,035	19,446,885	10/31/2021	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).
Narragansett Electric Co.	Algonquin	93401S	AFT-1S4	335	122,275	10/31/2021	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).
Narragansett Electric Co.	Algonquin	96004SC	AFT-1S3	1,695	618,675	10/31/2021	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).
Narragansett Electric Co.	Algonquin	9B105	AFT-1B	8,539	1,813,145	10/31/2021	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).
Narragansett Electric Co.	Algonquin	9S100S	AFT-1SX	187	39,737	10/31/2021	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).
Narragansett Electric Co.	Algonquin	9W009E	AFT-EW	6,812	1,446,384	10/31/2021	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).
Narragansett Electric Co.	Algonquin	510801	AFT1AIM	18,000	6,570,000	1/6/2032	No	Part-284 transportation service used to transport gas from Ramapo, NY (18,000 MMBtu) to National Grid - Westerly (500 MMBtu), National Grid - Warren (6,000 MMBtu), National Grid - Portsmouth (6,000 MMBtu), National Grid - Tiverton (500 MMBtu), and Yankee Gas - Montville (5,000 MMBtu).
Narragansett Electric Co.	Algonquin	510985	AFTCLMS	96,000	35,040,000	7/16/2032	No	Part-284 transportation service used to transport gas from Manchester Street Lateral on the G-12 System (Meter No. 80070) to National Grid - Crary Street-Providence, RI (96,000 MMBtu).
Narragansett Electric Co.	Columbia	31523	FTS	10,000	3,650,000	10/31/2025	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).

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
Narragansett Electric Co.	Columbia	31524	FTS	30,000	10,950,000	10/31/2025	No	Part-284 transportation service used to transport gas from Maumee-1 (30,000 MMBtu) to Columbia interconnect at Hanover, NJ (30,000 MMBtu).
Narragansett Electric Co.	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.
Narragansett Electric Co.	Dominion	100118	FTNN	537	196,005	3/31/2022	No	Part-284 transportation service used to transport gas from the TETCO interconnect at Oakford (537 MMBtu) or Dominion South Point (537 MMBtu) to the Leidy Group Meter (537 MMBtu).
Narragansett Electric Co.	Dominion	700086	FTGSS	2,061	311,211	3/31/2022	No	Transportation contract used to transport gas from DTI-GSS #300169 (2,061MMBtu) to the TETCO interconnect at Chambersburg, PA (2,061 MMBtu).
Narragansett Electric Co.	Dominion	700087	FTGSS	5,324	803,924	3/31/2021	No	Transportation contract used to transport gas from DTI-GSS #300170 (5,324MMBtu) to Ellisburg, PA (5,324 MMBtu).
Narragansett Electric Co.	Iroquois	50001	RTS-1	1,012	369,380	11/1/2022	No	Transportation contract used to transport gas from Waddington (1,012 MMBtu) to the IGTS interconnect with TGP at Wright, NY.
Narragansett Electric Co.	Millennium	210165	FT-1	9,000	3,285,000	3/31/2034	No	Transportation service used to transport gas from Corning, NY to the interconnect with Algonquin Gas Transmission at Ramapo, NY (9,000 MMBtu).
Narragansett Electric Co.	PNGTS	225805	FT	29,000	9,382,325	10/31/2040	No	Transportation service used to transport gas from East Hereford to the interconnect with Tennessee Gas Pipeline at Dracut (25,705 MMBtu+ 3,295 MMBtu Phase III expected ISD November 1, 2020).
Narragansett Electric Co.	Tennessee	10807	FT-A	10,836	3,955,140	3/31/2022	No	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).
Narragansett Electric Co.	Tennessee	39173	FT-A	1,067	389,455	10/31/2024	No	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).
Narragansett Electric Co.	Tennessee	1597	FT-A	29,335	10,707,275	10/31/2024	No	Transportation service used to transport gas from Zn1 800 Leg (6,160 MMBtu), Zn1 500 Leg (13,091 MMBtu), Zn0 100 Leg (9,522 MMBtu), and Zn1 100 Leg (562 MMBtu) to National Grid city gates at Pawtucket, RI (14,335 MMBtu), Cranston (10,000 MMBtu), and Smithfield (5,000 MMBtu).
Narragansett Electric Co.	Tennessee	62930	FT-A	15,000	5,475,000	8/31/2022	No	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).
Narragansett Electric Co.	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). If volumes transported to points other than primary points as listed on the contract, maximum commodity rate per TGP's tariff apply.
Narragansett Electric Co.	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). If volumes transported to points other than primary points as listed on the contract, maximum commodity rate per TGP's tariff apply.
Narragansett Electric Co.	Tennessee	95345	FT-A	1,000	365,000	10/31/2022	No	Transportation service used to transport gas from interconnect at Wright, NY (1,000 MMBtu) to National Grid city gates at Lincoln (1,000 MMBtu).
Narragansett Electric Co.	Tennessee	330580	FT-A	24,000	8,760,000	10/31/2038	No	Transportstion service used to transport gas from the interconnects at Dracut (14,000 MMBtu) and at Distrigas (10,000 MMBtu) to National Grid city gate - Lincoln (24,000).
Narragansett Electric Co.	Tennessee	330581	FT-A	15,000	5,475,000	10/31/2038	No	Transportstion service used to transport gas from the interconnect at Distrigas (15,000 MMBtu) to National Grid city gate - Cranston (15,000).
Narragansett Electric Co.	Tennessee	349449	FT-A	20,000	7,300,000	10/31/2025	No	Transportstion service used to transport gas from the interconnect at Dracut (20,000 MMBtu) to National Grid city gate - Cranston (20,000).

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
Narragansett Electric Co.	Texas Eastern	330844	FTS	6,377	2,327,605	10/31/2021	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).
Narragansett Electric Co.	Texas Eastern	330845	FTS	537	196,005	10/31/2021	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).
Narragansett Electric Co.	Texas Eastern	330867	FTS-5	813	296,745	3/31/2022	Yes	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (813 MMBtu) to Lambertville, NJ (813 MMBtu).
Narragansett Electric Co.	Texas Eastern	330870	FTS-5	1,000	365,000	3/31/2022	Yes	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (1,000 MMBtu) to Lambertville, NJ (1,000 MMBtu).
Narragansett Electric Co.	Texas Eastern	330907	FTS-5	248	90,520	3/31/2022	Yes	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (248 MMBtu) to Lambertville, NJ (248 MMBtu).
Narragansett Electric Co.	Texas Eastern	331722	FTS-7	538	196,370	3/31/2022	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).
Narragansett Electric Co.	Texas Eastern	331801	FTS-8	79	28,835	3/31/2022	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.
Narragansett Electric Co.	Texas Eastern	331802	FTS-8	187	68,255	3/31/2022	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.
Narragansett Electric Co.	Texas Eastern	331819	FTS-8	4,745	1,731,925	3/31/2022	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).
Narragansett Electric Co.	Texas Eastern	800156	SCT	2,099	766,135	10/31/2021	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).
Narragansett Electric Co.	Texas Eastern	800303	CDS	45,934	16,765,910	10/31/2021	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).
Narragansett Electric Co.	Texas Eastern	800440	CDS	944	344,560	10/31/2021	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).
Narragansett Electric Co.	TransCanada	42386	FT	1,012	369,380	10/31/2024	No	Transportation service used to transport gas from the Union Gas interconnect at Parkway to the interconnect with Iroquois Gas Transmission at Waddington (1,012 MMBtu).
Narragansett Electric Co.	TransCanada	58577	FT	10,757	3,926,305	10/31/2040	No	Transportation service used to transport gas from the Union Gas interconnect at Parkway to the interconnect with Portland Natural Gas Transmission System at East Hereforf (10,757 MMBtu).
Narragansett Electric Co.	TransCanada	60659	FT	18,294	5,474,635	10/31/2040	No	Transportation service used to transport gas from the Union Gas interconnect at Parkway to the interconnect with Portland Natural Gas Transmission System at East Hereford (14,999 MMBtu+approximately 3,295 MMBtu).
Narragansett Electric Co.	Transco	9081767	FT	1,240	452,600	3/31/2021	Yes	Part-284 transportation service used to transport gas from Transco Leidy (1,240 MMBtu) to the Algonquin interconnect at Centerville, NJ (1,240 MMBtu).
Narragansett Electric Co.	Union Gas	M12164	M12	1,025	374,125	10/31/2021	No	Transportation service used to transport gas from Dawn, Ontario to the interconnect with TransCanada Pipeline at Parkway (1,025 MMBtu).
Narragansett Electric Co.	Union Gas	M12274	M12	29,051	9,400,940	10/31/2040	No	Transportation service used to transport gas from Dawn, Ontario to the interconnect with TransCanada Pipeline at Parkway (25,756 MMBtu+approx 3,295 MMBtu).

NATIONAL GRID - RHODE ISLAND ASSETS
Storage Contracts

Shipper	Company	Contract No.	Rate Schedule	MDWQ	Annual Quantity	Expiration Date	Currently In Evergreen	Notes
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.
Narragansett Electric	Dominion	300168	GSS	1,401	154,050	3/31/2022	No	Part-284 storage service that provides storage capacity with an injection rate of 856 MMBtu/day.
Narragansett Electric	Dominion	300169	GSS	2,061	206,100	3/31/2022	No	Part-284 storage service that provides storage capacity with an injection rate of 1,145 MMBtu/day.
Narragansett Electric	Dominion	300170	GSS	5,324	490,340	3/31/2022	No	Part-284 storage service that provides storage capacity with an injection rate of 2,724 MMBtu/day.
Narragansett Electric	Dominion	300171	GSS	2,617	188,814	3/31/2022	No	Part-284 storage service that provides storage capacity with an injection rate of 1,049 MMBtu/day.
Narragansett Electric	Dominion	600045	GSS-TE	14,337	1,376,324	3/31/2022	No	Part-157 (7C) storage service that provides storage capacity with an injection rate of 7,647 MMBtu/day.
Narragansett Electric	Tennessee	501	FSMA	10,920	605,343	10/31/2025	No	Storage service that provides storage capacity at an injection rate of 4,036 MMBtu/day.
Narragansett Electric	Tennessee	62918	FSMA	10,249	210,000	10/31/2025	No	Storage service that provides storage capacity at an injection rate of 1,400 MMBtu/day.
Narragansett Electric	Texas Eastern	400185	SS-1	665	51,990	4/30/2022	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).]
Narragansett Electric	Texas Eastern	400221	SS-1	14,137	1,188,033	4/30/2022	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).]
Narragansett Electric	Texas Eastern	400515	FSS-1	944	56,640	4/30/2022	Yes	Part-284 storage service that provides storage capacity with an injection rate of 291 MMBtu/day.
Narragansett Electric	NGLNG	LNG003	FST-LG	95,000	600,000	10/31/2020	Yes	LNG Service Provider

National Grid Rhode Island
Contract Path Mapping

Contract Name	Path
TGP 1597	TGP Long Haul
TGP 64025	TGP ConneXion
TGP 64026	TGP ConneXion
TGP 10807	Storage Delivery
TGP 39173	Niagara
TGP 330580	Dawn via PNGTS
TGP 330580	Everett
TGP 330581	Everett
UN M12274	Dawn via PNGTS
TCPL 58577	Dawn via PNGTS
PNGTS 210203	Dawn via PNGTS
TGP 62930	Dawn via PNGTS
UN M12164	Dawn via Waddington
TCPL 42386	Dawn via Waddington
IGT 50001	Dawn via Waddington
TGP 95345	Dawn via Waddington
TRA 9081767	Transco
AGT 90106	Transco
AGT 96004SC	Transco
DETI 100118	Dominion
TET 330845	Dominion
AGT 96004SC	Dominion
AGT 90106	Storage Delivery
AGT 93401S	Storage Delivery
AGT 9W009E	Storage Delivery
TET 800440	Storage Delivery
AGT 9B105	Storage Delivery
TET 330907	Storage Delivery
TET 330867	Storage Delivery
TET 330870	Storage Delivery
AGT 933005	Storage Delivery
TET 330844	Storage Delivery
TET 331801	Storage Delivery
TET 331802	Storage Delivery
TET 331722	Storage Delivery
TET 331819	Storage Delivery
AGT 9S100S	Storage Delivery
AGT 93011E	TETCO CDS Long Haul
TET 800303	TETCO CDS Long Haul
MPL 214129	AIM
AGT 510801	AIM
TET 800156	TETCO SCT Long Haul
AGT 93001ESC	TETCO SCT Long Haul

National Grid Rhode Island
Contract Path Mapping

Contract Name	Path
TCO 31524	TCO (Pool)
TCO 31524	Storage Delivery
TCO 31523	TCO (Pool)
TCO 9631	Storage Delivery
AGT 90107	TCO (Pool)
AGT 90106	TCO (Pool)
AGT 9001	TCO (Pool)
LNG	LNG
DETI 700086	Storage Delivery
DETI 700087	Storage Delivery
Yankee Interconnect	Yankee Interconnect
Manchester Lateral	Manchester Lateral
TGP 349449	Dracut
AGT Citygate	Citygate Peaking
Summer Trucking	LNG
Winter Trucking	LNG
Constel 0416	Everett
TCO 9630	Storage
DETI 300168	Storage
DETI 300169	Storage
DETI 300170	Storage
DETI 300171	Storage
DETI 600045	Storage
TGP 501	Storage
TGP 62918	Storage
TET 400185	Storage
TET 400221	Storage
TET 400515	Storage
LNG_Prov	LNG
LNG_Exeter	LNG
Proposed Dracut Supply Deal	Dracut
Proposed Everett Supply Deal	Everett
Portable LNG	Portable LNG
AGT 93001ESC	AGT M3
AGT 93011E	AGT M3
Summer Liquid Refill	LNG
Proposed Summer Liquid	LNG
Proposed Summer Trucking	LNG

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

		Design Day with Existing Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	67	69	71	73	73
	Providence	298	305	314	321	322
	Warren	11	11	12	12	12
	Westerly	6	7	7	7	7
Fuel Reimbursement		6	6	37	445	473
Underground Storage Refill		0	0	0	0	0
LNG Refill		0	0	0	0	0
TOTAL		389	398	441	858	886
RESOURCES						
TGP	Dawn PNGTS	29	29	29	29	29
	Dawn Iroquois	1	1	1	1	1
	Niagara	1	1	1	1	1
	Zone 4	41	41	41	41	41
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	20	20	0	0	0
	Storage	11	11	11	11	11
TET/AGT	M2	49	49	49	49	49
	Dominion South Point	1	1	1	1	1
	TCO Appalachia	41	41	41	41	41
	Transco Leidy	1	1	1	1	1
	AIM (Ramapo)	8	9	9	9	9
	AIM (Millennium)	9	9	9	9	9
	M3	18	18	18	18	18
	AGT Citygate	14	14	14	0	0
	Storage	29	29	29	29	29
Liquid for Portables and Refill		0	6	0	0	0
LNG From Storage		116	119	76	95	119
Unserved	Valley	0	0	47	59	52
	Providence	0	0	64	461	472
	Warren	0	0	0	4	4
	Westerly	0	0	0	0	0
		0	0	111	523	528
TOTAL		389	398	441	858	886

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

Design Heating Season (Nov-Mar) with Existing Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	5,191	5,301	5,465	5,637	5,594
	Providence	22,952	23,439	24,166	24,925	24,736
	Warren	853	871	898	926	919
	Westerly	495	505	521	537	533
Fuel Reimbursement		714	722	726	738	728
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	192	192	0	0
TOTAL		30,397	31,029	31,969	32,763	32,510
RESOURCES						
TGP	Dawn PNGTS	2,511	2,497	2,537	2,669	2,638
	Dawn Iroquois	80	76	105	109	107
	Niagara	162	143	144	147	102
	Zone 4	5,724	5,628	5,892	6,030	6,204
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	651	651	0	0	0
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	7,158	7,140	7,177	7,214	7,025
	Dominion South Point	82	82	81	82	76
	TCO Appalachia	5,547	5,696	5,553	5,616	5,576
	Transco Leidy	160	148	137	155	164
	AIM (Ramapo)	351	377	429	466	461
	AIM (Millennium)	1,379	1,379	1,363	1,374	1,315
	M3	1,313	1,490	1,740	1,858	1,827
	AGT Citygate	497	508	508	0	0
	Storage	2,503	2,656	2,636	2,658	2,651
Liquid for Portables and Refill		192	197	192	0	0
LNG From Storage		542	565	757	753	752
Unserved	Valley	12	133	236	131	185
	Providence	197	329	1,146	2,163	2,088
	Warren	0	0	1	5	5
	Westerly	0	0	0	0	0
		209	462	1,384	2,299	2,279
TOTAL		30,397	31,029	31,969	32,763	32,510

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice) with Existing Resources
(BBtu)

		Design Non-Heating Season (Apr-Oct)				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	2,011	2,075	2,122	2,122	2,129
	Providence	8,892	9,174	9,383	9,381	9,413
	Warren	330	341	349	349	350
	Westerly	192	198	202	202	203
Fuel Reimbursement		314	372	404	318	343
Underground Storage Refill		3,838	3,995	3,975	3,996	3,989
LNG Refill		295	508	887	887	887
TOTAL		15,872	16,663	17,322	17,255	17,314
RESOURCES						
TGP	Dawn PNGTS	20	28	31	32	33
	Dawn Iroquois	57	7	1	1	1
	Niagara	59	64	2	2	2
	Zone 4	3,224	3,396	4,593	6,285	6,293
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	5,980	8,150	6,735	3,420	4,349
	Dominion South Point	16	17	15	0	0
	TCO Appalachia	396	893	896	336	319
	Transco Leidy	17	18	18	18	18
	AIM (Ramapo)	34	52	31	32	30
	AIM (Millennium)	1,123	930	723	230	438
	M3	4,515	2,969	4,136	6,759	5,689
	AGT Citygate	0	0	0	0	0
	Storage	1	5	4	4	4
Liquid for Portables and Refill		295	0	0	0	0
LNG From Storage		134	134	134	134	134
Unserved	Valley	0	0	0	0	0
	Providence	0	0	2	3	3
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	2	3	3
TOTAL		15,872	16,663	17,322	17,255	17,314

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

		Design Annual with Existing Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	7,202	7,376	7,587	7,759	7,723
	Providence	31,843	32,613	33,549	34,306	34,150
	Warren	1,184	1,212	1,247	1,275	1,269
	Westerly	686	703	723	739	736
Fuel Reimbursement		1,028	1,094	1,130	1,056	1,071
Underground Storage Refill		3,838	3,995	3,975	3,996	3,989
LNG Refill		488	699	1,079	887	887
TOTAL		46,269	47,692	49,290	50,018	49,824
RESOURCES						
TGP	Dawn PNGTS	2,532	2,525	2,568	2,701	2,671
	Dawn Iroquois	136	83	106	110	108
	Niagara	222	207	146	149	105
	Zone 4	8,948	9,024	10,485	12,314	12,497
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	651	651	0	0	0
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	13,138	15,290	13,912	10,633	11,373
	Dominion South Point	99	99	96	82	76
	TCO Appalachia	5,943	6,588	6,449	5,952	5,895
	Transco Leidy	178	166	156	173	181
	AIM (Ramapo)	385	428	460	497	490
	AIM (Millennium)	2,502	2,309	2,086	1,604	1,754
	M3	5,828	4,459	5,876	8,617	7,516
	AGT Citygate	497	508	508	0	0
	Storage	2,504	2,661	2,641	2,662	2,655
Liquid for Portables and Refill		488	197	192	0	0
LNG From Storage		676	699	891	887	886
Unserved	Valley	12	133	236	131	185
	Providence	197	329	1,148	2,166	2,091
	Warren	0	0	1	5	5
	Westerly	0	0	0	0	0
		209	462	1,386	2,302	2,282
TOTAL		46,269	47,692	49,290	50,018	49,824

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap (Sales and Customer Choice)
(BBtu)

Cold Snap Heating Season (Nov-Mar) with Existing Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	4,662	4,761	4,909	5,060	5,024
	Providence	20,873	21,315	21,978	22,656	22,495
	Warren	752	768	792	817	811
	Westerly	450	460	474	488	485
Fuel Reimbursement		666	676	687	699	682
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	197	192	0	0
TOTAL		27,595	28,177	29,032	29,720	29,496
RESOURCES						
TGP	Dawn PNGTS	1,808	1,842	1,998	2,136	2,102
	Dawn Iroquois	53	50	84	89	89
	Niagara	162	139	140	142	86
	Zone 4	5,078	5,041	5,387	5,569	5,986
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	639	651	0	0	0
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	6,976	6,967	7,141	7,119	6,712
	Dominion South Point	82	82	78	80	71
	TCO Appalachia	5,409	5,563	5,343	5,481	5,440
	Transco Leidy	143	117	115	134	155
	AIM (Ramapo)	141	177	287	314	314
	AIM (Millennium)	1,379	1,379	1,316	1,333	1,234
	M3	648	793	1,089	1,216	1,199
	AGT Citygate	231	256	409	0	0
	Storage	2,520	2,690	2,662	2,668	2,661
Liquid for Portables and Refill		192	197	192	0	0
LNG From Storage		542	570	757	753	753
Unserved	Valley	42	74	136	158	171
	Providence	214	255	560	1,187	1,182
	Warren	2	1	1	6	6
	Westerly	0	0	0	0	0
		258	331	697	1,351	1,359
TOTAL		27,595	28,177	29,032	29,720	29,496

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap (Sales and Customer Choice)
(BBtu)

Cold Snap Non-Heating Season (Apr-Oct) with Existing Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	1,856	1,916	1,959	1,959	1,965
	Providence	8,312	8,577	8,771	8,769	8,798
	Warren	300	309	316	316	317
	Westerly	179	185	189	189	190
Fuel Reimbursement		304	360	393	306	332
Underground Storage Refill		3,855	4,025	3,998	4,004	3,997
LNG Refill		295	508	887	887	887
TOTAL		15,101	15,879	16,514	16,430	16,485
RESOURCES						
TGP	Dawn PNGTS	4	10	16	16	17
	Dawn Iroquois	50	6	0	0	0
	Niagara	53	58	1	1	1
	Zone 4	2,998	3,180	4,401	6,124	6,133
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	5,956	8,129	6,733	3,399	4,305
	Dominion South Point	16	17	12	0	0
	TCO Appalachia	322	775	797	271	268
	Transco Leidy	16	17	17	17	17
	AIM (Ramapo)	16	22	8	8	8
	AIM (Millennium)	1,117	887	691	167	401
	M3	4,121	2,643	3,703	6,291	5,200
	AGT Citygate	0	0	0	0	0
	Storage	1	1	1	2	2
Liquid for Portables and Refill		295	0	0	0	0
LNG From Storage		134	134	134	134	134
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		15,101	15,879	16,514	16,430	16,485

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap (Sales and Customer Choice)
(BBtu)

		Cold Snap Annual with Existing Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	6,518	6,676	6,868	7,019	6,989
	Providence	29,185	29,892	30,749	31,425	31,293
	Warren	1,052	1,078	1,109	1,133	1,128
	Westerly	629	644	663	677	675
Fuel Reimbursement		969	1,036	1,079	1,005	1,014
Underground Storage Refill		3,855	4,025	3,998	4,004	3,997
LNG Refill		488	705	1,080	887	887
TOTAL		42,696	44,056	45,545	46,149	45,982
RESOURCES						
TGP	Dawn PNGTS	1,812	1,852	2,014	2,152	2,119
	Dawn Iroquois	103	56	84	89	89
	Niagara	216	197	141	143	87
	Zone 4	8,076	8,220	9,788	11,693	12,120
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	639	651	0	0	0
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	12,933	15,096	13,874	10,518	11,017
	Dominion South Point	98	99	90	80	71
	TCO Appalachia	5,731	6,338	6,140	5,752	5,708
	Transco Leidy	159	134	132	151	172
	AIM (Ramapo)	156	198	294	322	322
	AIM (Millennium)	2,496	2,266	2,007	1,500	1,635
	M3	4,769	3,436	4,793	7,508	6,400
	AGT Citygate	231	256	409	0	0
	Storage	2,521	2,691	2,664	2,669	2,662
Liquid for Portables and Refill		488	197	192	0	0
LNG From Storage		676	705	891	887	887
Unserved	Valley	42	74	136	158	171
	Providence	214	255	560	1,187	1,182
	Warren	2	1	1	6	6
	Westerly	0	0	0	0	0
		258	331	697	1,351	1,359
TOTAL		42,696	44,056	45,545	46,149	45,982

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

Design Day with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	67	69	71	73	73
	Providence	298	305	314	321	322
	Warren	11	11	12	12	12
	Westerly	6	7	7	7	7
Fuel Reimbursement		6	6	6	7	7
Underground Storage Refill		0	0	0	0	0
LNG Refill		0	0	0	0	0
TOTAL		389	398	410	420	421
RESOURCES						
TGP	Dawn PNGTS	29	29	29	29	29
	Dawn Iroquois	1	1	1	1	1
	Niagara	1	1	1	1	1
	Zone 4	41	41	41	41	41
	Dracut	20	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	20	20	0	0	0
	Everett Swing	5	5	25	30	30
	Storage	11	11	11	11	11
TET/AGT	M2	49	49	49	49	49
	Dominion South Point	1	1	1	1	1
	TCO Appalachia	41	41	41	41	41
	Transco Leidy	1	1	1	1	1
	AIM (Ramapo)	8	9	9	9	9
	AIM (Millennium)	9	9	9	9	9
	M3	18	18	18	18	18
	AGT Citygate	14	14	14	0	0
	Storage	29	29	29	29	29
Liquid for Portables and Refill		0	1	10	0	0
LNG From Storage		91	119	119	119	119
Unserved	Valley	0	0	0	9	9
	Providence	0	0	2	20	20
	Warren	0	0	0	4	4
	Westerly	0	0	0	0	0
		0	0	2	32	32
TOTAL		389	398	410	420	421

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

Design Heating Season (Nov-Mar) with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	5,191	5,301	5,465	5,637	5,594
	Providence	22,952	23,439	24,166	24,925	24,736
	Warren	853	871	898	926	919
	Westerly	495	505	521	537	533
Fuel Reimbursement		714	721	722	733	723
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	251	210	94	94
TOTAL		30,397	31,088	31,983	32,852	32,600
RESOURCES						
TGP	Dawn PNGTS	2,507	2,491	2,523	2,649	2,618
	Dawn Iroquois	79	76	104	108	107
	Niagara	162	143	144	147	102
	Zone 4	5,727	5,623	5,886	6,022	6,204
	Dracut	200	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	651	651	0	0	0
	Everett Swing	25	323	1,532	1,940	1,910
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	7,159	7,135	7,173	7,210	7,024
	Dominion South Point	82	82	81	82	76
	TCO Appalachia	5,547	5,696	5,551	5,616	5,576
	Transco Leidy	161	148	137	155	164
	AIM (Ramapo)	349	359	325	354	350
	AIM (Millennium)	1,379	1,379	1,361	1,373	1,310
	M3	1,303	1,434	1,524	1,602	1,570
	AGT Citygate	500	497	430	0	0
	Storage	2,514	2,679	2,670	2,668	2,658
Liquid for Portables and Refill		192	263	245	94	94
LNG From Storage		526	774	960	847	847
Unserved	Valley	0	0	0	32	29
	Providence	0	0	2	614	621
	Warren	0	0	0	5	5
	Westerly	0	0	0	0	0
		0	0	2	651	656
TOTAL		30,397	31,088	31,983	32,852	32,600

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

Design Non-Heating Season (Apr-Oct) with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	2,011	2,075	2,122	2,122	2,129
	Providence	8,892	9,174	9,383	9,381	9,413
	Warren	330	341	349	349	350
	Westerly	192	198	202	202	203
Fuel Reimbursement		314	373	405	318	343
Underground Storage Refill		3,849	4,017	4,007	4,006	3,996
LNG Refill		468	658	887	890	891
TOTAL		16,056	16,835	17,355	17,268	17,325
RESOURCES						
TGP	Dawn PNGTS	20	28	32	32	33
	Dawn Iroquois	57	7	1	1	1
	Niagara	59	64	2	2	2
	Zone 4	3,224	3,397	4,593	6,285	6,293
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Everett Swing	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	5,980	8,150	6,735	3,420	4,349
	Dominion South Point	16	17	15	0	0
	TCO Appalachia	406	915	929	346	326
	Transco Leidy	17	18	18	18	18
	AIM (Ramapo)	34	52	31	32	30
	AIM (Millennium)	1,123	930	723	230	438
	M3	4,516	2,969	4,136	6,759	5,689
	AGT Citygate	0	0	0	0	0
	Storage	1	4	3	3	4
Liquid for Portables and Refill		468	150	0	3	4
LNG From Storage		134	134	137	137	138
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		16,056	16,835	17,355	17,268	17,325

National Grid Rhode Island
Comparison of Resources and Requirements
Design Year (Sales and Customer Choice)
(BBtu)

		Design Annual with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	7,202	7,376	7,587	7,759	7,723
	Providence	31,843	32,613	33,549	34,306	34,150
	Warren	1,184	1,212	1,247	1,275	1,269
	Westerly	686	703	723	739	736
Fuel Reimbursement		1,028	1,094	1,127	1,052	1,066
Underground Storage Refill		3,849	4,017	4,007	4,006	3,996
LNG Refill		661	908	1,097	984	984
TOTAL		46,453	47,922	49,337	50,120	49,924
RESOURCES						
TGP	Dawn PNGTS	2,527	2,520	2,555	2,681	2,651
	Dawn Iroquois	135	83	105	109	108
	Niagara	222	207	146	149	105
	Zone 4	8,951	9,020	10,479	12,307	12,497
	Dracut	200	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	651	651	0	0	0
	Everett Swing	25	323	1,532	1,940	1,910
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	13,139	15,285	13,908	10,630	11,372
	Dominion South Point	99	99	96	82	76
	TCO Appalachia	5,953	6,610	6,480	5,962	5,902
	Transco Leidy	178	166	156	173	181
	AIM (Ramapo)	383	411	356	386	379
	AIM (Millennium)	2,502	2,309	2,084	1,603	1,749
	M3	5,819	4,403	5,659	8,361	7,259
	AGT Citygate	500	497	430	0	0
	Storage	2,515	2,683	2,673	2,672	2,662
Liquid for Portables and Refill		661	413	245	97	98
LNG From Storage		661	908	1,097	984	984
Unserved	Valley	0	0	0	32	29
	Providence	0	0	2	614	621
	Warren	0	0	0	5	5
	Westerly	0	0	0	0	0
		0	0	2	651	656
TOTAL		46,453	47,922	49,337	50,120	49,924

National Grid Rhode Island
Comparison of Resources and Requirements
Normal Year (Sales and Customer Choice)
(BBtu)

		Normal Heating Season (Nov-Mar) with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	4,447	4,541	4,683	4,829	4,793
	Providence	19,911	20,332	20,965	21,620	21,457
	Warren	718	733	756	779	774
	Westerly	429	438	452	466	463
Fuel Reimbursement		656	663	670	682	666
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	192	192	0	0
TOTAL		26,353	26,901	27,718	28,376	28,152
RESOURCES						
TGP	Dawn PNGTS	1,732	1,744	1,867	2,003	1,974
	Dawn Iroquois	49	47	81	84	84
	Niagara	162	139	140	142	83
	Zone 4	5,034	5,019	5,362	5,576	5,983
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	502	558	0	0	0
	Everett Swing	25	117	854	1,127	1,112
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	6,968	6,940	7,112	7,108	6,690
	Dominion South Point	82	82	78	80	71
	TCO Appalachia	5,409	5,563	5,353	5,481	5,440
	Transco Leidy	143	113	112	133	154
	AIM (Ramapo)	21	34	80	86	87
	AIM (Millennium)	1,379	1,379	1,313	1,336	1,256
	M3	448	451	534	542	542
	AGT Citygate	0	0	0	0	0
	Storage	2,520	2,690	2,679	2,695	2,690
Liquid for Portables and Refill		192	192	192	0	0
LNG From Storage		354	498	626	647	651
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		26,353	26,901	27,718	28,376	28,152

National Grid Rhode Island
Comparison of Resources and Requirements
Normal Year (Sales and Customer Choice)
(BBtu)

Normal Non-Heating Season (Apr-Oct) with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	1,856	1,916	1,959	1,959	1,965
	Providence	8,312	8,577	8,771	8,769	8,798
	Warren	300	309	316	316	317
	Westerly	179	185	189	189	190
Fuel Reimbursement		304	357	379	306	331
Underground Storage Refill		3,855	4,025	4,015	4,031	4,025
LNG Refill		295	440	568	781	785
TOTAL		15,101	15,809	16,197	16,350	16,411
RESOURCES						
TGP	Dawn PNGTS	4	10	15	16	17
	Dawn Iroquois	50	6	0	0	0
	Niagara	53	58	1	1	1
	Zone 4	2,998	3,178	4,397	6,124	6,133
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Everett Swing	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	5,956	8,077	6,638	3,399	4,305
	Dominion South Point	16	17	10	0	0
	TCO Appalachia	322	728	739	294	292
	Transco Leidy	16	16	17	17	17
	AIM (Ramapo)	16	19	5	5	5
	AIM (Millennium)	1,117	887	691	167	401
	M3	4,121	2,624	3,549	6,192	5,105
	AGT Citygate	0	0	0	0	0
	Storage	1	1	1	1	1
Liquid for Portables and Refill		295	51	0	0	0
LNG From Storage		134	134	134	134	134
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		15,101	15,809	16,197	16,350	16,411

National Grid Rhode Island
Comparison of Resources and Requirements
Normal Year (Sales and Customer Choice)
(BBtu)

		Normal Annual with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	6,304	6,457	6,642	6,787	6,758
	Providence	28,223	28,909	29,737	30,389	30,255
	Warren	1,017	1,042	1,072	1,096	1,091
	Westerly	608	623	641	655	652
Fuel Reimbursement		959	1,020	1,049	988	997
Underground Storage Refill		3,855	4,025	4,015	4,031	4,025
LNG Refill		488	632	760	781	785
TOTAL		41,454	42,709	43,916	44,726	44,563
RESOURCES						
TGP	Dawn PNGTS	1,736	1,754	1,882	2,019	1,990
	Dawn Iroquois	99	53	81	84	84
	Niagara	216	197	141	143	84
	Zone 4	8,032	8,197	9,759	11,701	12,117
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	502	558	0	0	0
	Everett Swing	25	117	854	1,127	1,112
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	12,924	15,017	13,751	10,507	10,995
	Dominion South Point	98	99	89	80	71
	TCO Appalachia	5,731	6,291	6,092	5,775	5,733
	Transco Leidy	159	130	129	150	171
	AIM (Ramapo)	37	53	85	91	92
	AIM (Millennium)	2,496	2,266	2,003	1,503	1,657
	M3	4,569	3,076	4,083	6,734	5,647
	AGT Citygate	0	0	0	0	0
	Storage	2,521	2,691	2,680	2,696	2,691
Liquid for Portables and Refill		488	244	192	0	0
LNG From Storage		488	632	760	781	785
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		41,454	42,709	43,916	44,726	44,563

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap (Sales and Customer Choice)
(BBtu)

		Cold Snap Heating Season (Nov-Mar) with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	4,662	4,761	4,909	5,060	5,024
	Providence	20,873	21,315	21,978	22,656	22,495
	Warren	753	768	792	817	811
	Westerly	450	460	474	488	485
Fuel Reimbursement		666	674	682	693	677
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	211	119	29	29
TOTAL		27,595	28,189	28,953	29,743	29,521
RESOURCES						
TGP	Dawn PNGTS	1,808	1,821	1,957	2,093	2,065
	Dawn Iroquois	53	50	83	86	86
	Niagara	162	139	140	142	86
	Zone 4	5,078	5,045	5,386	5,581	5,986
	Dracut	200	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	639	651	0	0	0
	Everett Swing	25	184	974	1,259	1,243
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	6,976	6,947	7,127	7,111	6,689
	Dominion South Point	82	82	78	80	71
	TCO Appalachia	5,409	5,563	5,351	5,481	5,440
	Transco Leidy	143	117	115	133	155
	AIM (Ramapo)	141	156	209	218	219
	AIM (Millennium)	1,379	1,379	1,312	1,336	1,256
	M3	648	768	870	898	899
	AGT Citygate	231	231	246	0	0
	Storage	2,520	2,690	2,679	2,695	2,690
Liquid for Portables and Refill		192	211	212	29	29
LNG From Storage		575	735	872	782	782
Unserved	Valley	0	35	0	11	41
	Providence	0	51	7	468	443
	Warren	0	1	0	6	6
	Westerly	0	0	0	0	0
		0	87	7	485	489
TOTAL		27,595	28,189	28,953	29,743	29,521

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap (Sales and Customer Choice)
(BBtu)

Cold Snap Non-Heating Season (Apr-Oct) with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	1,856	1,916	1,959	1,959	1,965
	Providence	8,312	8,577	8,771	8,769	8,798
	Warren	300	309	316	316	317
	Westerly	179	185	189	189	190
Fuel Reimbursement		304	360	393	307	332
Underground Storage Refill		3,855	4,025	4,015	4,031	4,025
LNG Refill		516	658	887	887	887
TOTAL		15,322	16,029	16,531	16,457	16,514
RESOURCES						
TGP	Dawn PNGTS	4	10	16	16	17
	Dawn Iroquois	50	6	0	0	0
	Niagara	53	58	1	1	1
	Zone 4	2,998	3,180	4,401	6,124	6,133
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Everett Swing	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	5,956	8,129	6,733	3,399	4,305
	Dominion South Point	16	17	12	0	0
	TCO Appalachia	322	775	815	299	297
	Transco Leidy	16	17	17	17	17
	AIM (Ramapo)	16	22	8	8	8
	AIM (Millennium)	1,117	887	691	167	401
	M3	4,121	2,643	3,703	6,291	5,200
	AGT Citygate	0	0	0	0	0
	Storage	1	1	1	1	1
Liquid for Portables and Refill		516	150	0	0	0
LNG From Storage		134	134	134	134	134
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		15,322	16,029	16,531	16,457	16,514

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap (Sales and Customer Choice)
(BBtu)

Cold Snap Annual with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	6,518	6,676	6,868	7,019	6,989
	Providence	29,185	29,892	30,749	31,425	31,293
	Warren	1,052	1,078	1,109	1,133	1,128
	Westerly	629	644	663	677	675
Fuel Reimbursement		969	1,034	1,075	1,000	1,009
Underground Storage Refill		3,855	4,025	4,015	4,031	4,025
LNG Refill		709	869	1,006	916	916
TOTAL		42,917	44,218	45,484	46,200	46,035
RESOURCES						
TGP	Dawn PNGTS	1,812	1,832	1,972	2,110	2,082
	Dawn Iroquois	103	56	83	86	86
	Niagara	216	197	141	143	87
	Zone 4	8,076	8,225	9,787	11,705	12,120
	Dracut	200	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	639	651	0	0	0
	Everett Swing	25	184	974	1,259	1,243
	Storage	1,334	1,334	1,334	1,334	1,334
TET/AGT	M2	12,933	15,076	13,860	10,510	10,994
	Dominion South Point	98	99	90	80	71
	TCO Appalachia	5,731	6,338	6,166	5,780	5,737
	Transco Leidy	159	134	132	150	172
	AIM (Ramapo)	156	177	217	226	227
	AIM (Millennium)	2,496	2,266	2,003	1,502	1,657
	M3	4,769	3,411	4,573	7,190	6,100
	AGT Citygate	231	231	246	0	0
	Storage	2,521	2,691	2,680	2,696	2,691
Liquid for Portables and Refill		709	361	212	29	29
LNG From Storage		709	869	1,006	916	916
Unserved	Valley	0	35	0	11	41
	Providence	0	51	7	468	443
	Warren	0	1	0	6	6
	Westerly	0	0	0	0	0
		0	87	7	485	489
TOTAL		42,917	44,218	45,484	46,200	46,035

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

		Design Day with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	58	59	60	62	62
	Providence	254	260	267	274	274
	Warren	9	10	10	10	10
	Westerly	5	6	6	6	6
Fuel Reimbursement		5	5	5	5	5
Underground Storage Refill		0	0	0	0	0
LNG Refill		0	0	0	0	0
TOTAL		332	339	349	357	357
RESOURCES						
TGP	Dawn PNGTS	24	24	24	24	24
	Dawn Iroquois	1	1	1	1	1
	Niagara	1	1	1	1	1
	Zone 4	33	33	33	33	33
	Dracut	17	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	20	20	0	0	0
	Everett Swing	4	5	25	30	30
	Storage	10	10	10	10	10
TET/AGT	M2	39	39	39	39	39
	Dominion South Point	1	1	1	1	1
	TCO Appalachia	33	33	33	33	33
	Transco Leidy	1	1	1	1	1
	AIM (Ramapo)	7	7	7	7	7
	AIM (Millennium)	7	7	7	7	7
	M3	29	29	29	29	29
	AGT Citygate	14	0	2	0	0
	Storage	25	25	25	25	25
Liquid for Portables and Refill		0	2	10	0	0
LNG From Storage		67	101	101	101	101
Unserved	Valley	0	0	0	3	3
	Providence	0	0	0	11	12
	Warren	0	0	0	1	1
	Westerly	0	0	0	0	0
		0	0	0	15	16
TOTAL		332	339	349	357	357

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

Design Heating Season (Nov-Mar) with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	4,290	4,378	4,508	4,653	4,622
	Providence	18,970	19,359	19,933	20,573	20,435
	Warren	705	720	741	765	760
	Westerly	409	417	430	443	440
Fuel Reimbursement		577	580	582	590	582
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	185	172	94	94
TOTAL		25,143	25,640	26,366	27,117	26,933
RESOURCES						
TGP	Dawn PNGTS	2,268	2,081	2,130	2,200	2,179
	Dawn Iroquois	66	66	97	101	100
	Niagara	162	143	144	145	96
	Zone 4	4,619	4,489	4,757	4,778	4,976
	Dracut	105	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	651	651	0	0	0
	Everett Swing	25	347	1,418	1,882	1,865
	Storage	1,172	1,258	1,172	1,258	1,172
TET/AGT	M2	5,815	5,798	5,806	5,844	5,722
	Dominion South Point	82	82	82	83	78
	TCO Appalachia	4,459	4,607	4,505	4,554	4,523
	Transco Leidy	166	151	134	159	166
	AIM (Ramapo)	154	169	202	214	215
	AIM (Millennium)	1,113	1,113	1,108	1,115	1,078
	M3	1,882	2,157	2,166	2,227	2,193
	AGT Citygate	229	95	43	0	0
	Storage	1,611	1,611	1,611	1,582	1,581
Liquid for Portables and Refill		192	197	192	94	94
LNG From Storage		371	626	798	719	719
Unserved	Valley	0	0	0	3	5
	Providence	0	0	0	160	169
	Warren	0	0	0	1	1
	Westerly	0	0	0	0	0
		0	0	0	164	174
TOTAL		25,143	25,640	26,366	27,117	26,933

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

Design Non-Heating Season (Apr-Oct) with Proposed Resources

		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	1,477	1,520	1,554	1,560	1,570
	Providence	6,532	6,720	6,871	6,896	6,941
	Warren	243	250	255	256	258
	Westerly	141	145	148	149	150
Fuel Reimbursement		224	274	304	240	260
Underground Storage Refill		2,784	2,869	2,784	2,841	2,755
LNG Refill		295	557	742	742	742
TOTAL		11,696	12,335	12,659	12,684	12,675
RESOURCES						
TGP	Dawn PNGTS	4	10	14	14	15
	Dawn Iroquois	42	2	0	0	0
	Niagara	42	49	2	2	2
	Zone 4	2,480	2,731	3,661	5,186	5,107
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Everett Swing	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	4,049	5,858	4,875	2,170	2,948
	Dominion South Point	16	14	15	0	0
	TCO Appalachia	302	787	777	255	246
	Transco Leidy	16	17	16	16	16
	AIM (Ramapo)	25	34	16	13	13
	AIM (Millennium)	907	745	529	141	339
	M3	3,401	1,922	2,636	4,768	3,871
	AGT Citygate	0	0	0	0	0
	Storage	1	1	1	2	2
Liquid for Portables and Refill		295	50	0	0	0
LNG From Storage		117	117	117	117	117
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		11,696	12,335	12,659	12,684	12,675

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

		Design Annual with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	5,768	5,898	6,062	6,212	6,191
	Providence	25,502	26,080	26,805	27,469	27,377
	Warren	948	969	996	1,021	1,018
	Westerly	550	562	578	592	590
Fuel Reimbursement		800	854	886	831	842
Underground Storage Refill		2,784	2,869	2,784	2,841	2,755
LNG Refill		488	742	914	835	836
TOTAL		36,839	37,975	39,025	39,801	39,608
RESOURCES						
TGP	Dawn PNGTS	2,272	2,091	2,144	2,214	2,195
	Dawn Iroquois	108	68	97	101	100
	Niagara	205	192	146	148	98
	Zone 4	7,099	7,220	8,418	9,964	10,083
	Dracut	105	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	651	651	0	0	0
	Everett Swing	25	347	1,418	1,882	1,865
	Storage	1,172	1,258	1,172	1,258	1,172
TET/AGT	M2	9,864	11,656	10,681	8,014	8,670
	Dominion South Point	98	96	97	83	78
	TCO Appalachia	4,761	5,394	5,282	4,809	4,768
	Transco Leidy	182	168	150	175	182
	AIM (Ramapo)	179	202	219	227	229
	AIM (Millennium)	2,019	1,858	1,637	1,256	1,417
	M3	5,283	4,079	4,801	6,995	6,065
	AGT Citygate	229	95	43	0	0
	Storage	1,612	1,612	1,612	1,584	1,582
Liquid for Portables and Refill		488	247	192	94	94
LNG From Storage		488	742	914	835	836
Unserved	Valley	0	0	0	3	5
	Providence	0	0	0	160	169
	Warren	0	0	0	1	1
	Westerly	0	0	0	0	0
		0	0	0	164	174
TOTAL		36,839	37,975	39,025	39,801	39,608

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

		Normal Heating Season (Nov-Mar) with Proposed Resources				
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	3,646	3,721	3,831	3,953	3,927
	Providence	16,323	16,658	17,152	17,699	17,584
	Warren	588	601	618	638	634
	Westerly	352	359	370	382	379
Fuel Reimbursement		530	534	537	549	536
Underground Storage Refill		0	0	0	0	0
LNG Refill		192	192	192	0	0
TOTAL		21,631	22,064	22,700	23,221	23,060
RESOURCES						
TGP	Dawn PNGTS	1,692	1,473	1,578	1,744	1,707
	Dawn Iroquois	36	36	72	78	77
	Niagara	162	138	139	141	80
	Zone 4	4,180	4,061	4,385	4,422	4,778
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	476	497	0	0	0
	Everett Swing	25	85	706	957	949
	Storage	1,172	1,258	1,172	1,258	1,172
TET/AGT	M2	5,704	5,685	5,769	5,783	5,540
	Dominion South Point	81	82	80	81	73
	TCO Appalachia	4,352	4,525	4,364	4,446	4,415
	Transco Leidy	149	134	118	145	156
	AIM (Ramapo)	12	15	45	49	49
	AIM (Millennium)	1,113	1,113	1,084	1,097	1,034
	M3	302	707	820	849	850
	AGT Citygate	0	0	0	0	0
	Storage	1,611	1,611	1,611	1,611	1,611
Liquid for Portables and Refill		192	192	192	0	0
LNG From Storage		371	452	564	560	567
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		21,631	22,064	22,700	23,221	23,060

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

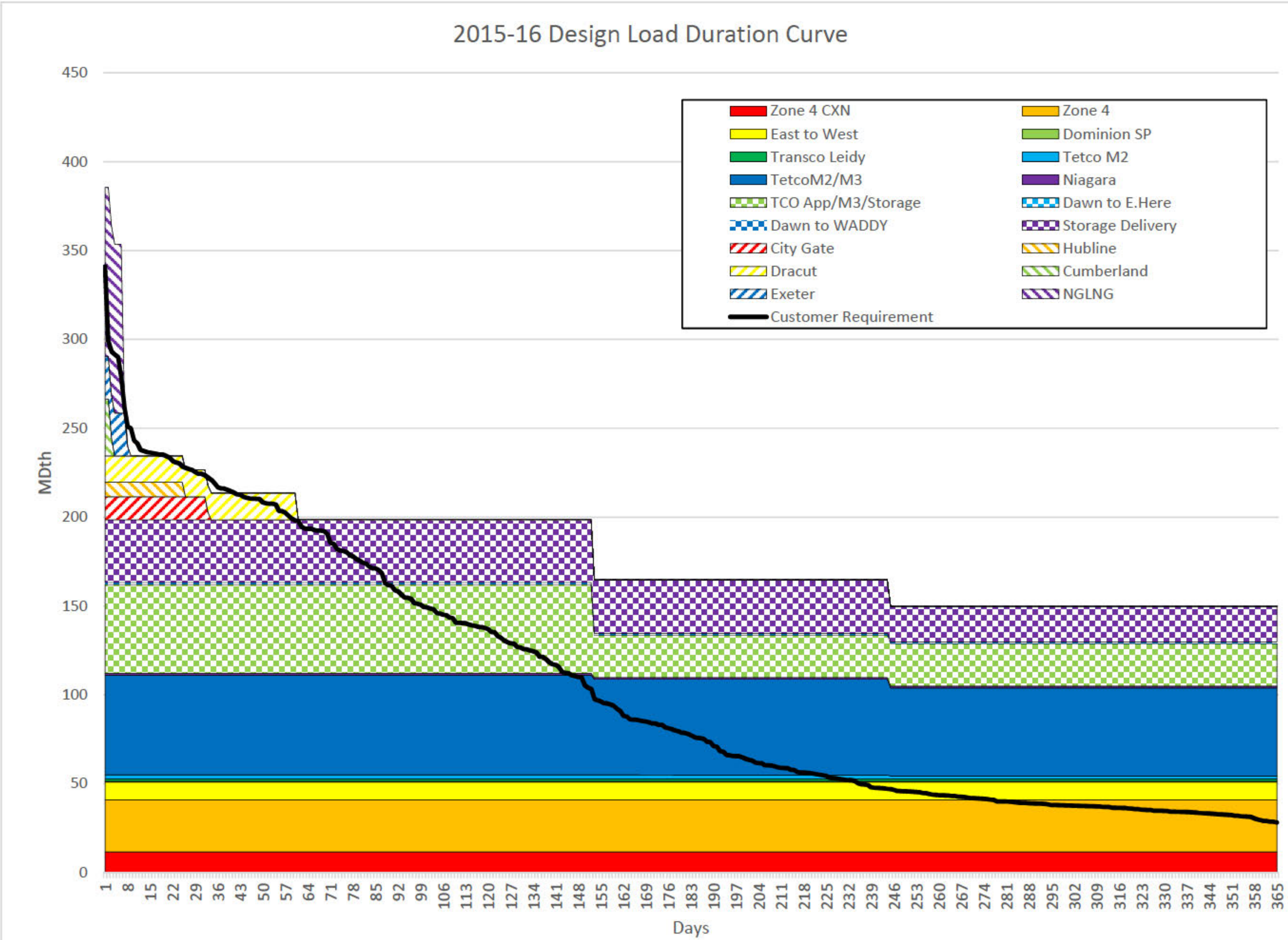
Normal Non-Heating Season (Apr-Oct) with Proposed Resources

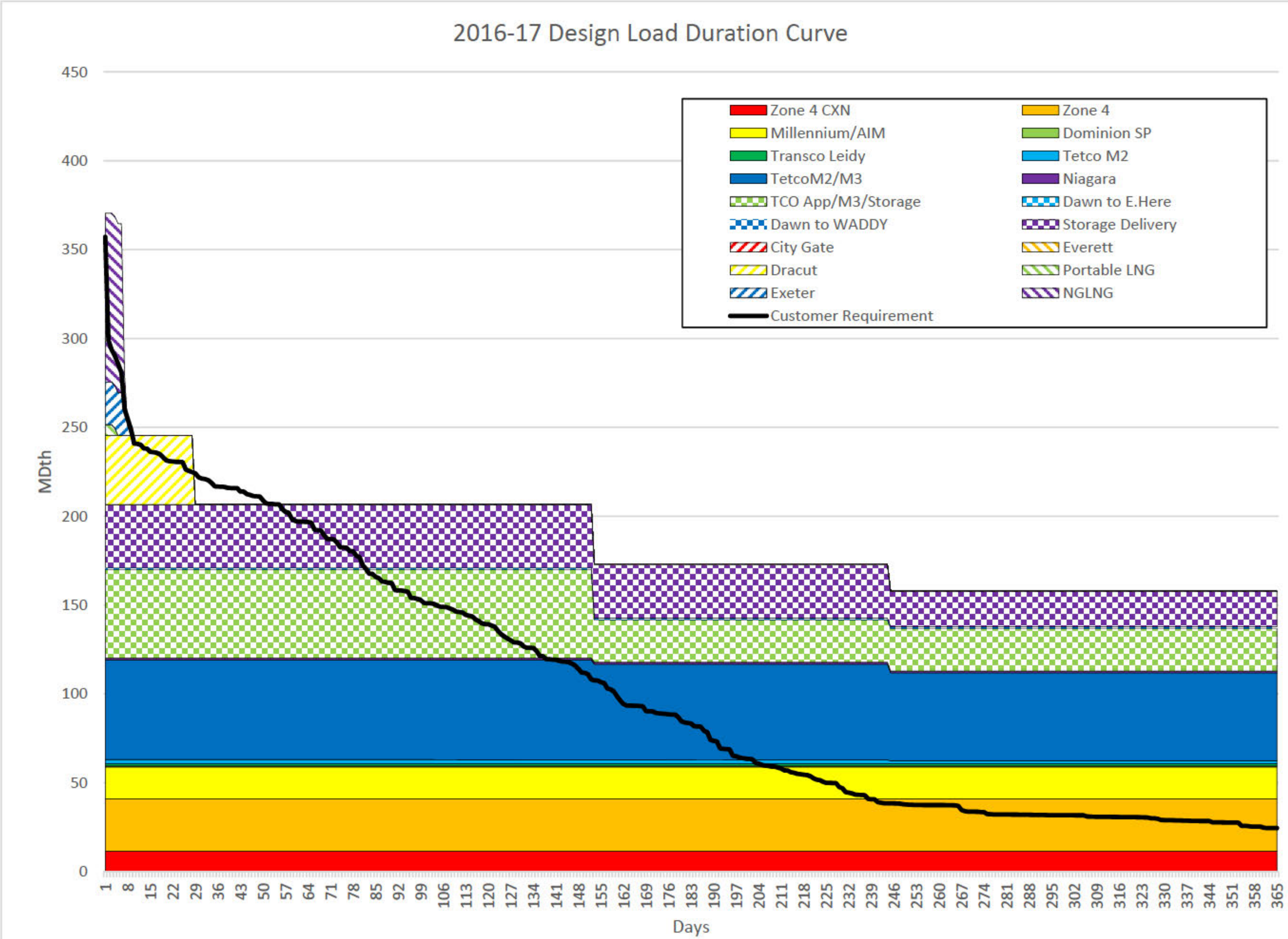
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	1,353	1,392	1,423	1,429	1,438
	Providence	6,059	6,233	6,373	6,397	6,439
	Warren	218	225	230	231	232
	Westerly	131	134	137	138	139
Fuel Reimbursement		215	259	281	231	250
Underground Storage Refill		2,783	2,868	2,783	2,868	2,783
LNG Refill		295	376	488	676	684
TOTAL		11,055	11,488	11,717	11,970	11,965
RESOURCES						
TGP	Dawn PNGTS	0	2	2	2	2
	Dawn Iroquois	39	1	0	0	0
	Niagara	40	45	1	1	1
	Zone 4	2,315	2,561	3,496	5,067	4,986
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	0	0	0	0	0
	Everett Swing	0	0	0	0	0
	Storage	0	0	0	0	0
TET/AGT	M2	4,018	5,690	4,744	2,126	2,860
	Dominion South Point	16	14	9	0	0
	TCO Appalachia	255	664	683	246	242
	Transco Leidy	16	16	16	16	16
	AIM (Ramapo)	8	13	1	2	2
	AIM (Millennium)	899	710	429	101	307
	M3	3,037	1,605	2,219	4,294	3,432
	AGT Citygate	0	0	0	0	0
	Storage	0	0	0	0	0
Liquid for Portables and Refill		295	50	0	0	0
LNG From Storage		117	117	117	117	117
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		11,055	11,488	11,717	11,970	11,965

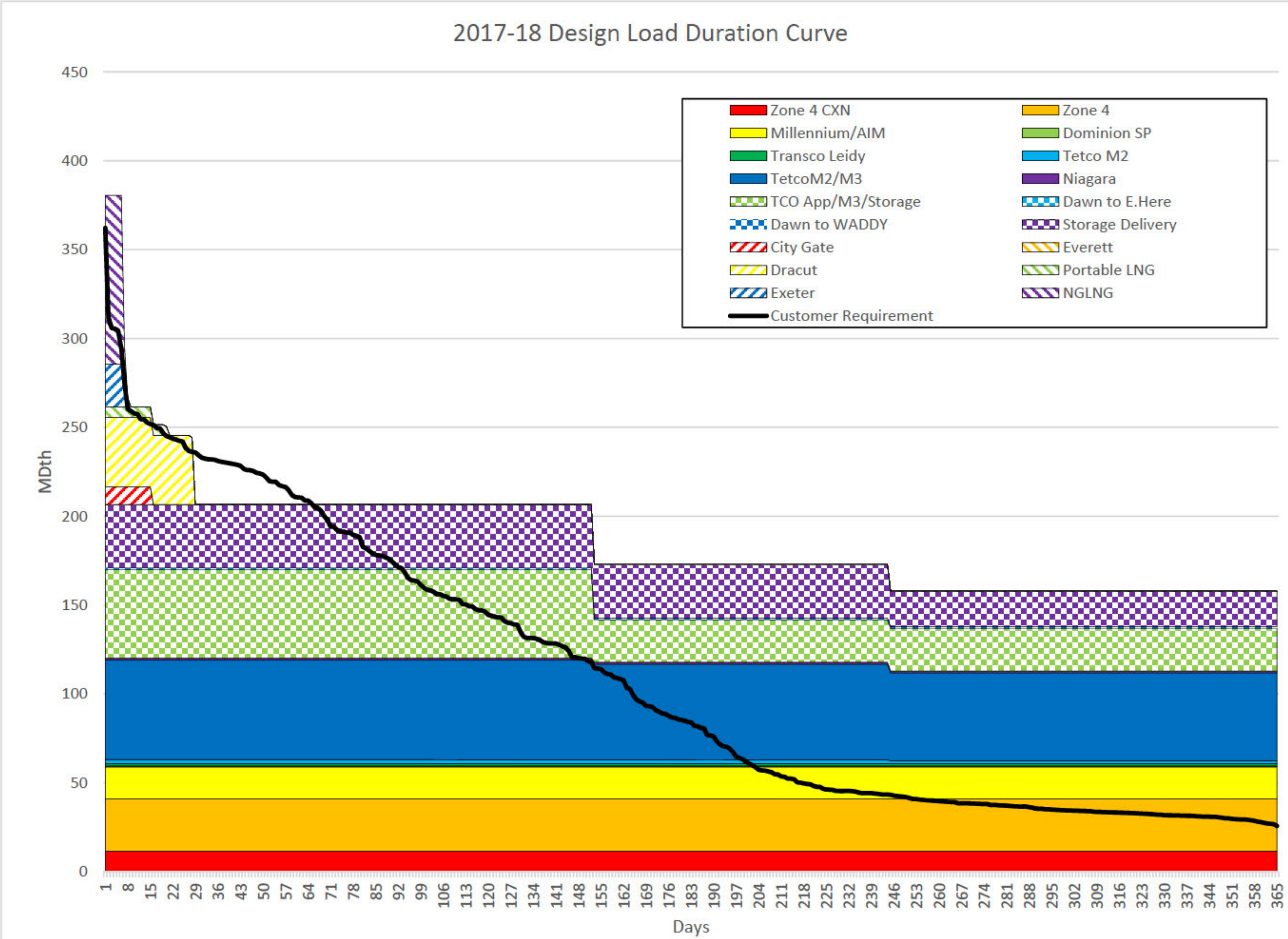
National Grid Rhode Island
Comparison of Resources and Requirements
Normal Year (Sales Only)
(BBtu)

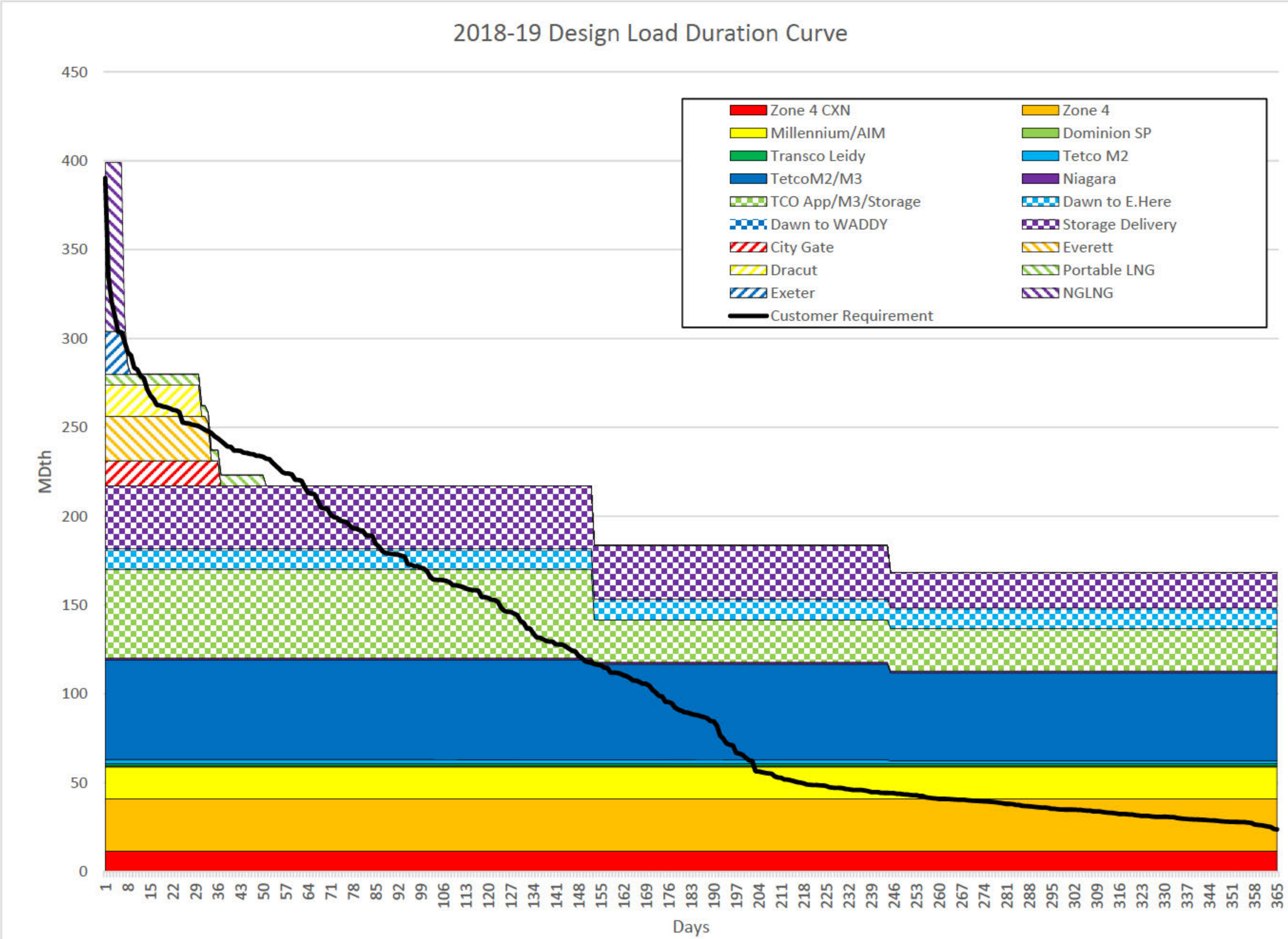
Normal Annual with Proposed Resources

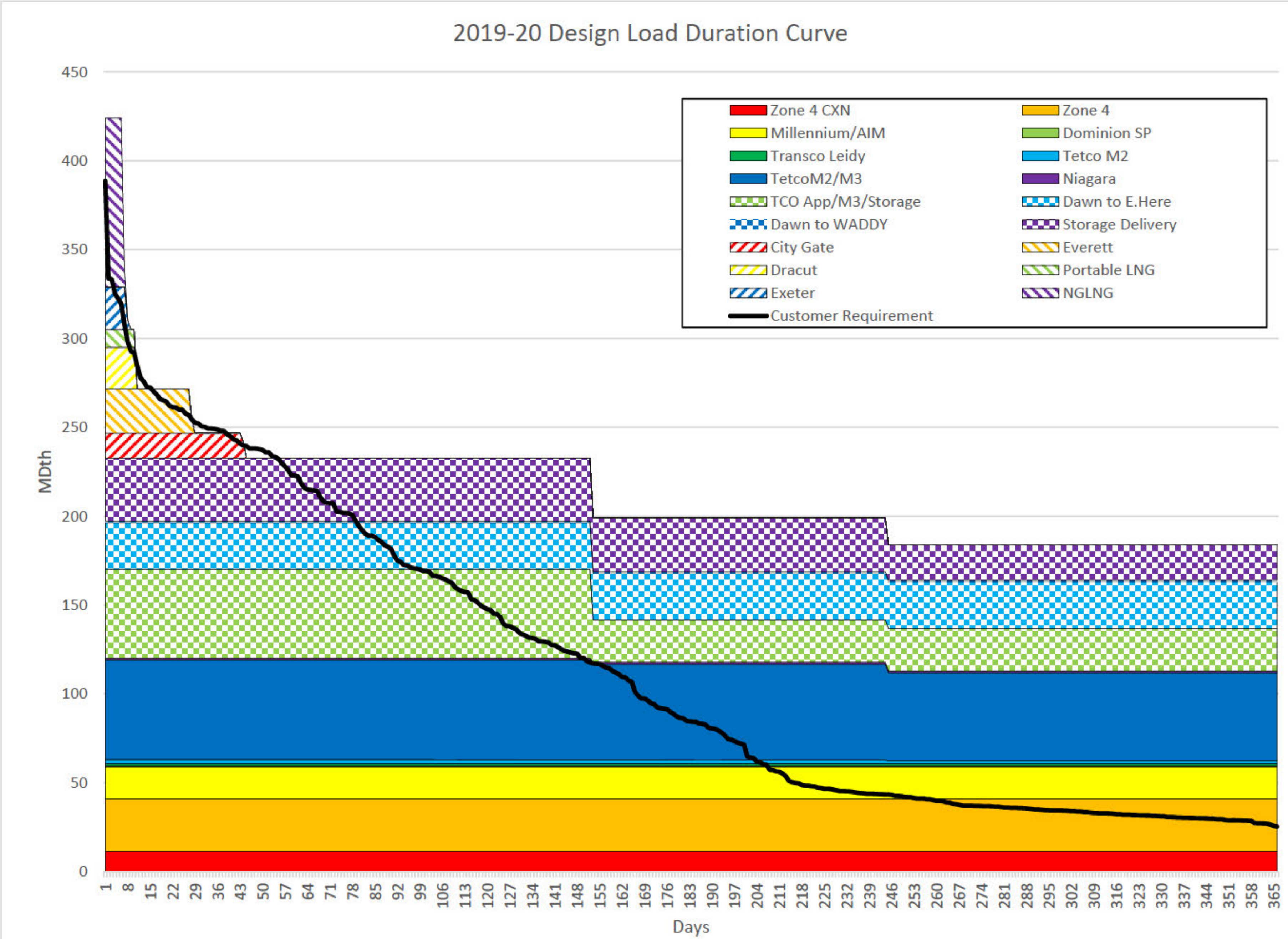
		2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
REQUIREMENTS						
Firm Sendout	Valley	4,999	5,113	5,254	5,382	5,365
	Providence	22,382	22,891	23,525	24,096	24,022
	Warren	807	825	848	869	866
	Westerly	483	494	507	519	518
Fuel Reimbursement		745	792	818	780	787
Underground Storage Refill		2,783	2,868	2,783	2,868	2,783
LNG Refill		488	568	681	676	684
TOTAL		32,686	33,552	34,417	35,191	35,026
RESOURCES						
TGP	Dawn PNGTS	1,692	1,474	1,580	1,747	1,710
	Dawn Iroquois	76	37	72	78	77
	Niagara	203	184	140	142	82
	Zone 4	6,494	6,622	7,881	9,489	9,764
	Dracut	0	0	0	0	0
	TGP Citygate	0	0	0	0	0
	Everett Multi Year	476	497	0	0	0
	Everett Swing	25	85	706	957	949
	Storage	1,172	1,258	1,172	1,258	1,172
TET/AGT	M2	9,722	11,375	10,513	7,909	8,400
	Dominion South Point	97	96	89	81	73
	TCO Appalachia	4,607	5,189	5,047	4,692	4,657
	Transco Leidy	164	150	134	160	172
	AIM (Ramapo)	20	29	46	51	52
	AIM (Millennium)	2,012	1,823	1,513	1,198	1,341
	M3	3,339	2,312	3,039	5,143	4,282
	AGT Citygate	0	0	0	0	0
	Storage	1,611	1,611	1,611	1,611	1,611
Liquid for Portables and Refill		488	242	192	0	0
LNG From Storage		488	568	681	676	684
Unserved	Valley	0	0	0	0	0
	Providence	0	0	0	0	0
	Warren	0	0	0	0	0
	Westerly	0	0	0	0	0
		0	0	0	0	0
TOTAL		32,686	33,552	34,417	35,191	35,026

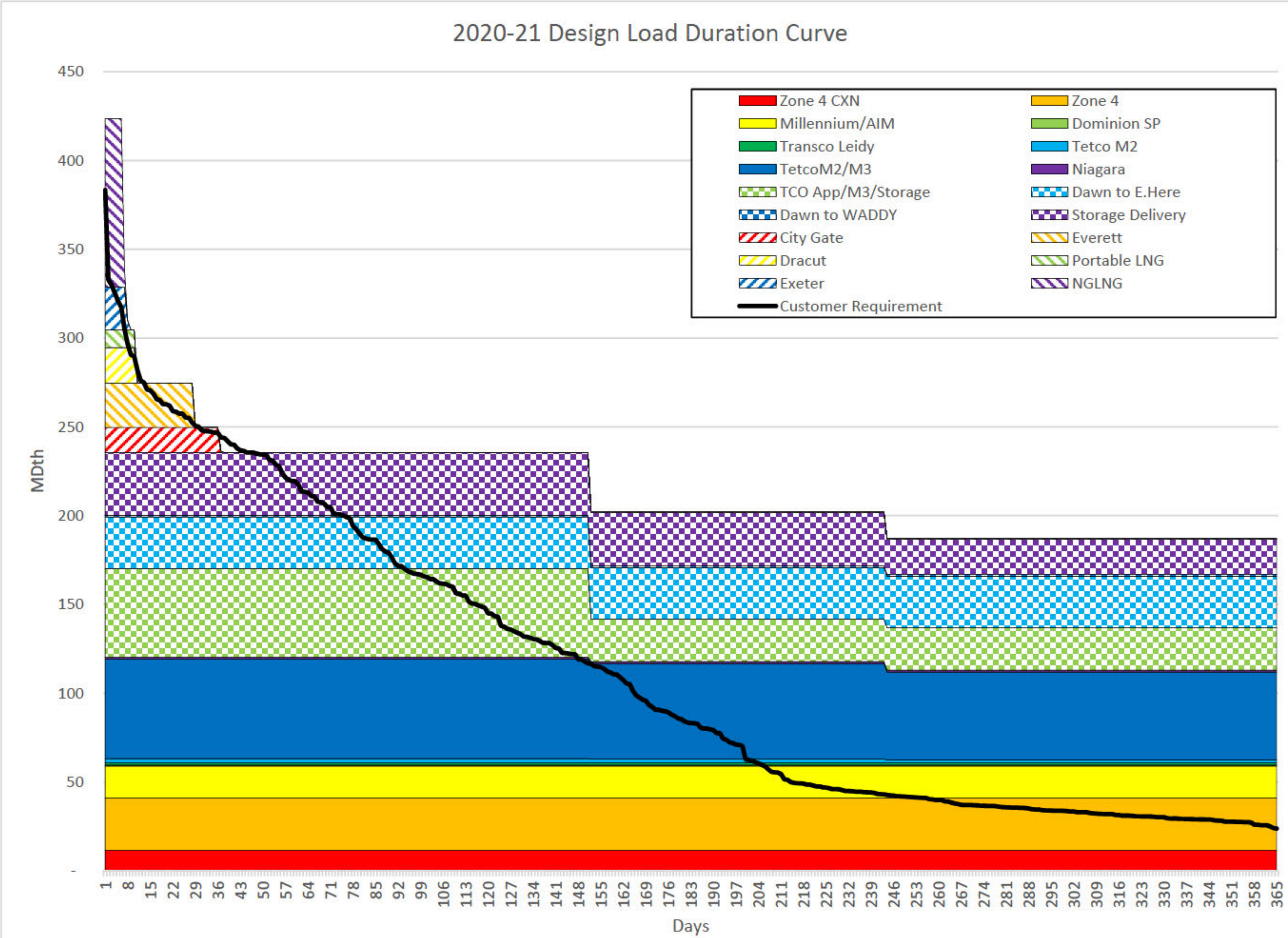

2015-16 Design Load Duration Curve
MDth
450
400
350
300
250
200
150
100
50
0
Days
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
169
176
183
190
197
204
211
218
225
232
239
246
253
260
267
274
281
288
295
302
309
316
323
330
337
344
351
358
365
Zone 4 CXN
Zone 4
East to West
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Hubline
Dracut
Cumberland
Exeter
NGLNG
Customer Requirement

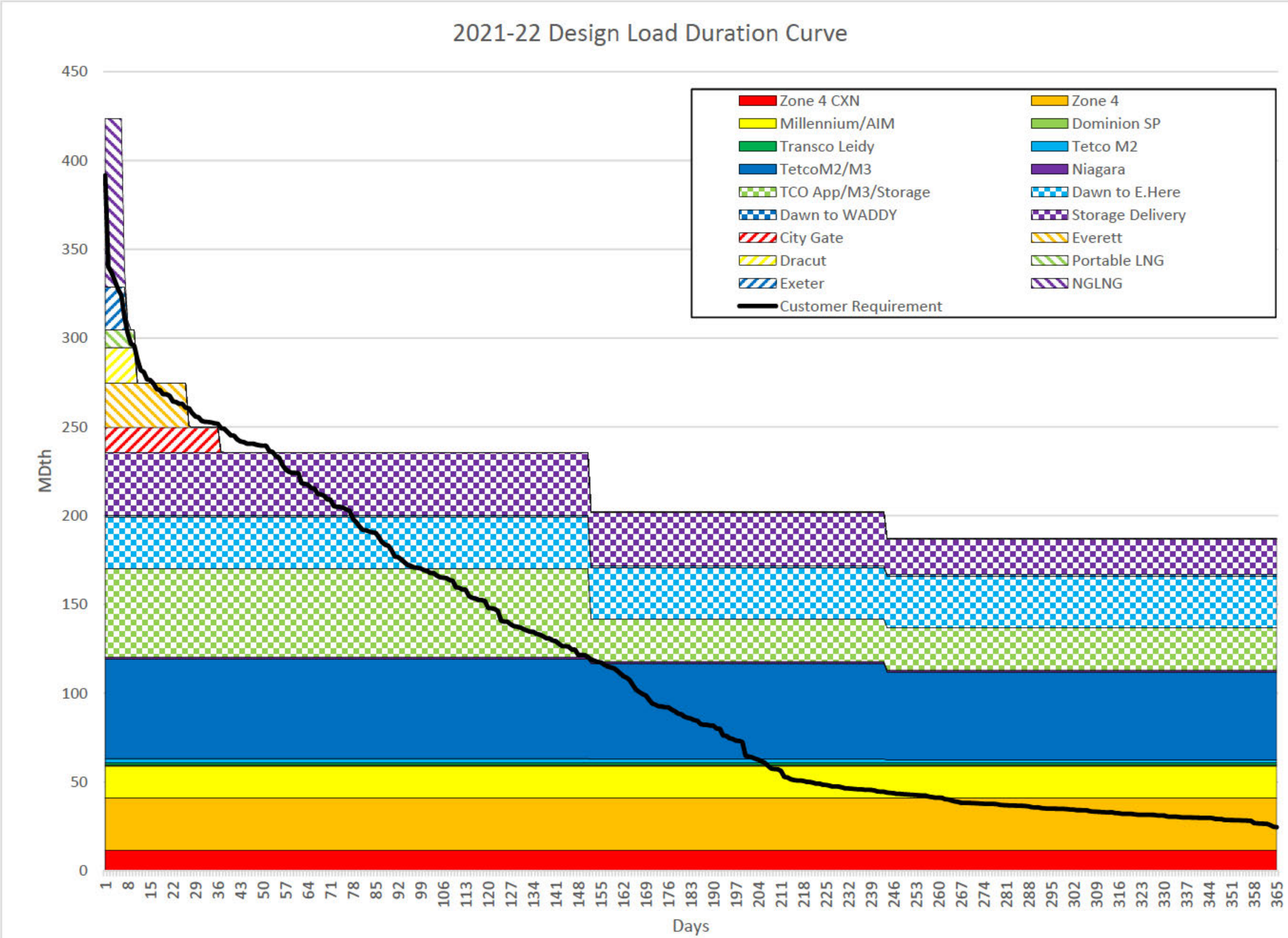

2016-17 Design Load Duration Curve
450
400
350
300
250
200
150
100
50
0
MDth
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162 169 176 183 190 197 204 211 218 225 232 239 246 253 260 267 274 281 288 295 302 309 316 323 330 337 344 351 358 365
Days

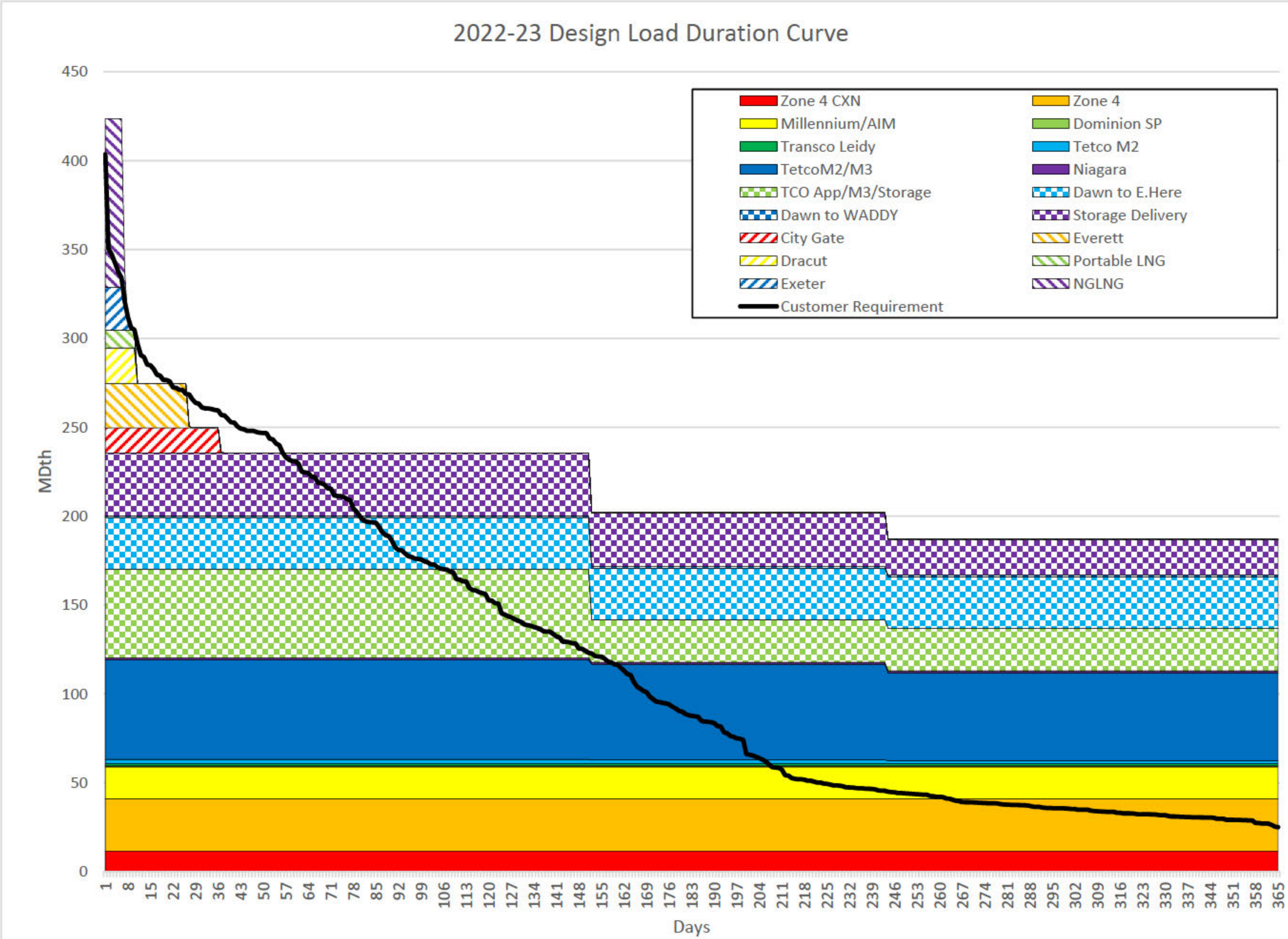

2017-18 Design Load Duration Curve
MDth
Days
0
50
100
150
200
250
300
350
400
450
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
169
176
183
190
197
204
211
218
225
232
239
246
253
260
267
274
281
288
295
302
309
316
323
330
337
344
351
358
365

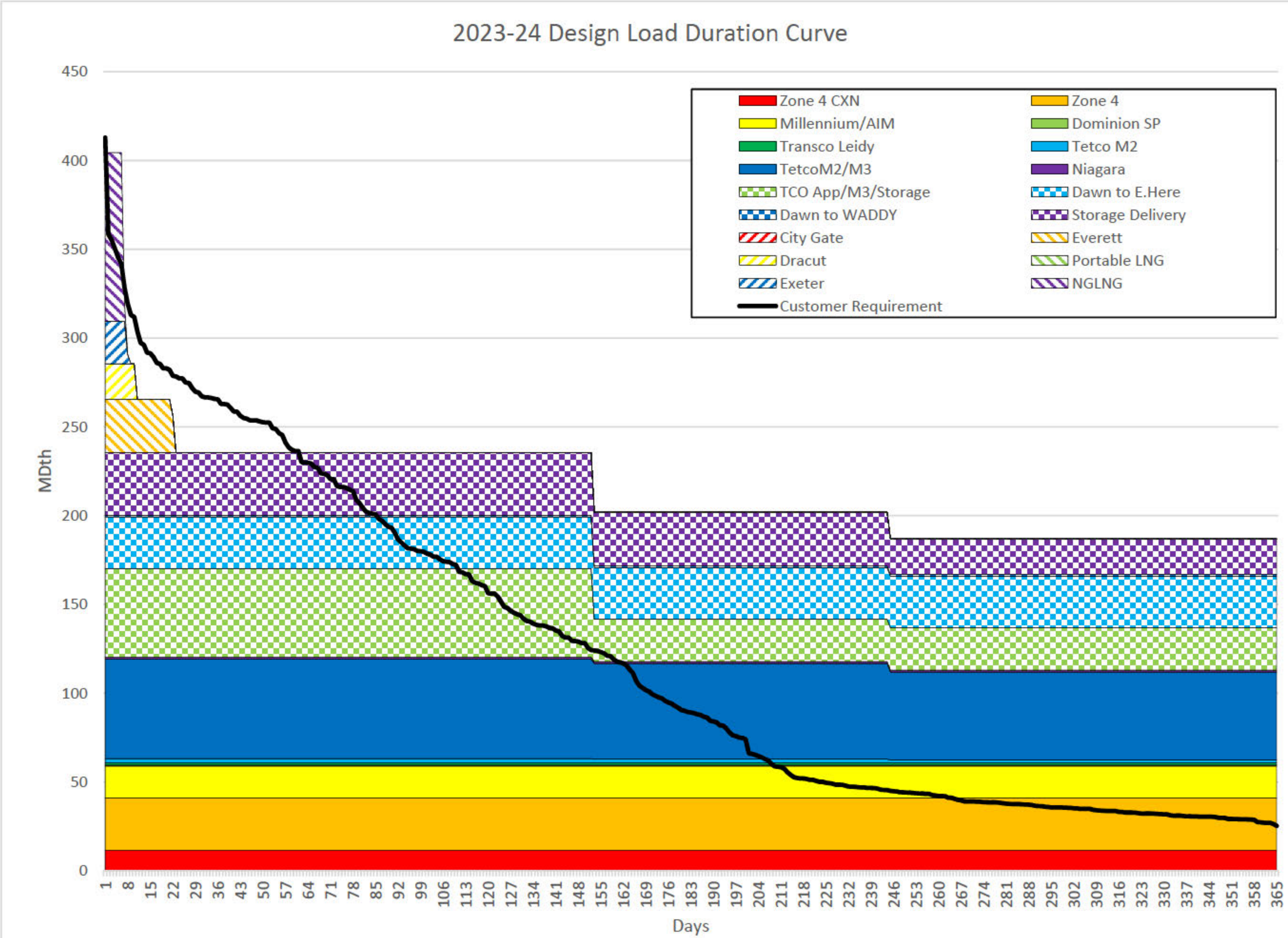

2018-19 Design Load Duration Curve
MDth
Days
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement

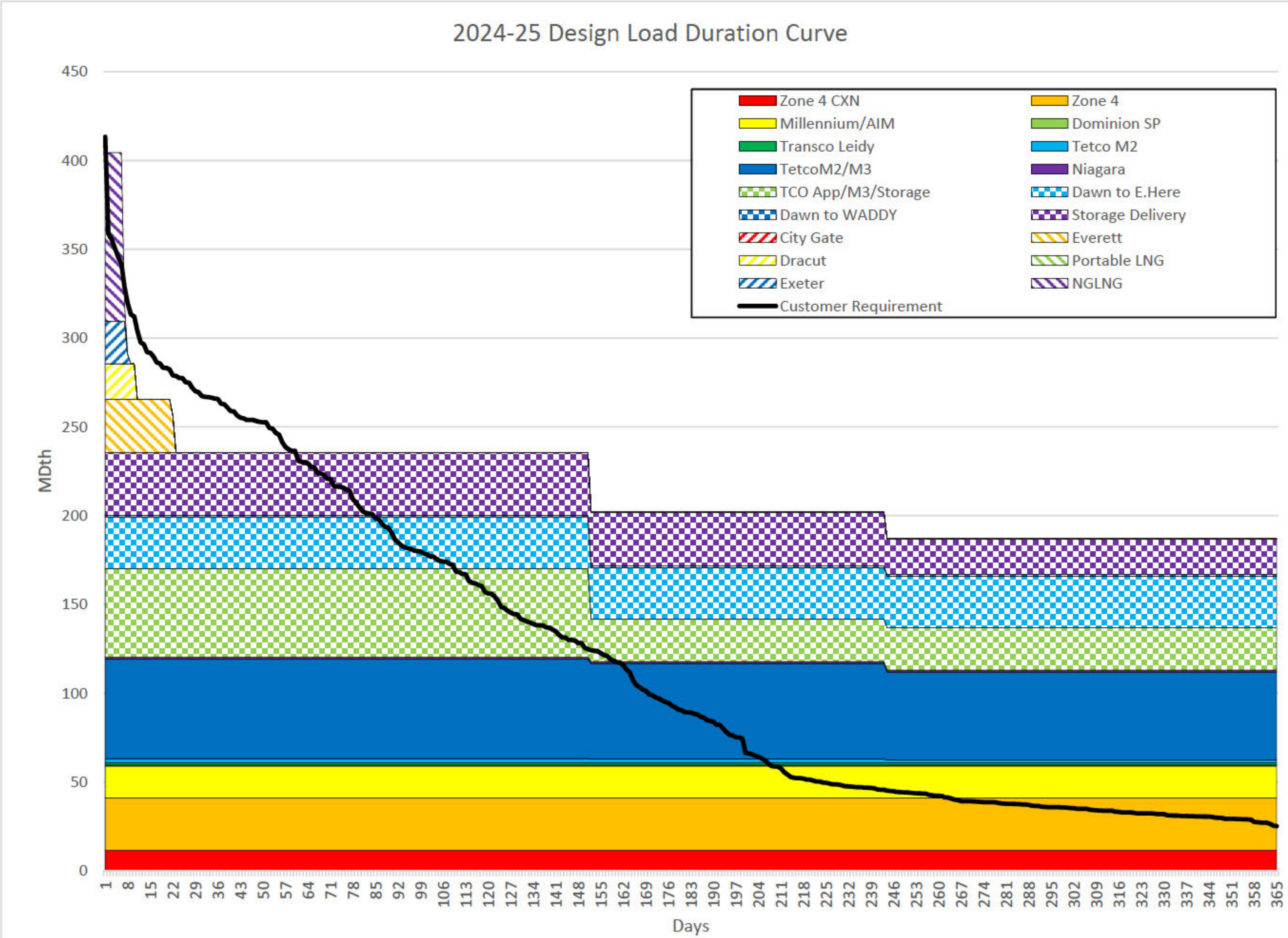

2019-20 Design Load Duration Curve
MDth
450
400
350
300
250
200
150
100
50
0
Days
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement


2020-21 Design Load Duration Curve
MDth
Days
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement


2021-22 Design Load Duration Curve
MDth
Days
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement


2022-23 Design Load Duration Curve
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement
MDth
Days


2023-24 Design Load Duration Curve
MDth
Days
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement


2024-25 Design Load Duration Curve
MDth
Days
Zone 4 CXN
Zone 4
Millennium/AIM
Dominion SP
Transco Leidy
Tetco M2
TetcoM2/M3
Niagara
TCO App/M3/Storage
Dawn to E.Here
Dawn to WADDY
Storage Delivery
City Gate
Everett
Dracut
Portable LNG
Exeter
NGLNG
Customer Requirement

National Grid Rhode Island **Gas Cost Recovery** **Cost of Gas ($000)**	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Design Weather Scenario - SCC Adj FT1													
FIXED COSTS													
Total Transportation Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Delivery Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Liquefaction Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Supplier Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LESS:													
AMA Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL FIXED COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 94,423.8
VARIABLE COSTS													
Commodity													
Commodity for Purchases to City Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity for Purchases to Injections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 104,495.4
Withdrawal													
Underground Storage Withdrawal Value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Storage Withdrawal Value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Withdrawal Value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 10,922.8
Transportation													
Variable Costs for Purchases to City Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Costs for Storage Withdrawal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Costs for Storage Injection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Transportation Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LESS:													
LNG Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Storage Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage and Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 11,415.0
TOTAL VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 108,590.8
TOTAL FIXED AND VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 203,014.6
NGPMP Credit	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 5,251.1
TOTAL GAS COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 197,763.5

Narragansett Electric Company
Volume & Cost Summary

Design Weather Scenario - SCC Adj FT1

Sendout Volumes (MDth)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Algonquin													
TETCO CDS Long Haul	1,343	1,390	1,396	1,261	1,375	1,338	479	378	764	1,046	434	1,373	12,577
TETCO SCT Long Haul	-	35	46	43	20	-	-	-	-	-	-	-	145
AIM	286	323	389	337	309	269	12	264	273	-	-	297	2,759
AGT M3	341	172	322	285	170	696	1,454	661	-	-	963	700	5,766
TCO Appalachia	616	1,226	1,226	1,108	1,226	199	54	49	-	45	32	18	5,798
Storage	7	438	656	554	421	1	-	-	-	-	-	-	2,078
Total Algonquin	2,593	3,585	4,036	3,589	3,522	2,503	2,000	1,351	1,037	1,091	1,429	2,388	29,123
Tennessee													
TGP Long Haul	845	780	868	771	665	305	87	75	-	-	75	343	4,815
TGP ConneXion	348	360	354	325	341	287	359	347	232	358	347	359	4,016
Storage	-	409	452	407	411	-	-	-	-	-	-	-	1,680
Total Tennessee	1,193	1,549	1,674	1,503	1,418	593	445	422	232	358	422	702	10,511
Other													
Dawn via PNGTS	100	588	712	693	358	20	-	-	-	-	-	-	2,472
Dracut	-	49	100	39	13	-	-	-	-	-	-	-	200
Dawn / Niagara / Waddington	36	50	56	53	43	60	47	7	0	-	-	-	353
Dominion / Transco Leidy	42	49	53	46	48	19	2	2	2	2	2	2	270
Everett	-	92	243	276	65	-	-	-	-	-	-	-	675
LNG Vapor	80	64	227	136	19	19	19	19	19	19	19	19	661
LNG Truck	-	-	-	-	192	107	127	136	9	5	65	19	661
City Gate	-	92	231	87	89	-	-	-	-	-	-	-	500
Total Other	259	983	1,622	1,330	828	226	196	164	31	26	86	41	5,791
Total Purchases	4,045	6,117	7,332	6,422	5,767	3,321	2,641	1,938	1,299	1,476	1,937	3,131	45,424
LESS:													
Liquefaction	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG Truck	-	-	-	-	192	107	127	136	9	5	65	19	661
AGT Storage Refill	-	-	-	-	-	64	529	427	267	309	466	453	2,515
TGP Storage Refill	-	-	-	-	-	45	201	264	101	224	248	251	1,334
Total	-	-	-	-	192	216	857	826	377	538	779	724	4,509
Total Sendout	4,045	6,117	7,332	6,422	5,574	3,105	1,784	1,111	922	938	1,157	2,407	40,915
Datacheck	4,045	6,117	7,332	6,422	5,574	3,105	1,784	1,111	922	938	1,157	2,407	40,915
Delta	-	-	-	-	-	-	-	-	-	-	-	-	-

Narragansett Electric Company
Volume & Cost Summary
Cost of Gas ($000)

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
DEMAND													
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 94,424
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 94,424
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COMMODITY													
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL COMMODITY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 120,006
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 120,006
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

TOTAL DC+CC	$ [redacted]												$ 214,430
LESS:													
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Liquefaction & Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 11,415
TOTAL GAS COST	[redacted]							[redacted]			[redacted]		$ 203,015
Commodity to Sendout	[redacted]	[redacted]				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	$ 108,591
Days/month	30	31	31	28	31	30	31	30	31	31	30	31	365
Unit Commodity Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2.654
NYMEX (06/08/20)	$2.376	$2.824	$2.961	$2.925	$2.809	$2.494	$2.461	$2.492	$2 530	$2.538	$2 521	$2.538	

National Grid Rhode Island Gas Cost Recovery Cost of Gas ($000)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Normal Weather Scenario - Sales Only													
FIXED COSTS													
Total Transportation Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Delivery Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Fixed Costs	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Liquefaction Fixed Costs	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Total Supplier Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 16,120.7
LESS:													
AMA Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL FIXED COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 80,442.1
VARIABLE COSTS													
Commodity													
Commodity for Purchases to City Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity for Purchases to Injections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Total Commodity Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 69,792.0
Withdrawal													
Underground Storage Withdrawal Value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
LNG Storage Withdrawal Value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Total Storage Withdrawal Value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,939.9
Transportation													
Variable Costs for Purchases to City Gate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Costs for Storage Withdrawa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Costs for Storage Injection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Transportation Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LESS:													
LNG Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Storage Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Liquefaction	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage and Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,884.7
TOTAL VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 73,160.5
TOTAL FIXED AND VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 153,602.6
NGPMP Credit	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] 5,251.1
TOTAL GAS COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 148,351.6

Narragansett Electric Company
Volume & Cost Summary
Sendout Volumes (MDth)

Normal Weather Scenario - Sales Only

Sendout Volumes (MDth)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Algonquin													
TETCO CDS Long Haul	1,080	1,098	1,127	1,017	1,090	1,062	205	198	505	745	198	995	9,320
TETCO SCT Long Haul	-	23	30	24	17	-	-	-	-	-	-	-	95
AIM	224	216	216	195	216	213	-	213	220	-	-	228	1,942
AGT M3	155	41	-	25	78	635	988	422	-	-	662	303	3,308
TCO Appalachia	373	990	990	894	990	51	50	49	-	49	32	18	4,487
Storage	-	222	502	424	169	-	-	-	-	-	-	-	1,317
Total Algonquin	1,833	2,591	2,865	2,580	2,560	1,961	1,244	882	725	794	892	1,544	20,469
Tennessee													
TGP Long Haul	562	513	670	596	419	161	27	84	-	-	76	224	3,333
TGP ConneXion	281	289	287	262	249	177	290	280	100	289	280	290	3,074
Storage	-	331	400	343	329	-	-	-	-	-	-	-	1,404
Total Tennessee	843	1,133	1,357	1,202	998	338	317	364	100	289	356	513	7,810
Other													
Dawn via PNGTS	43	377	474	491	269	-	-	-	-	-	-	-	1,655
Dracut	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn / Niagara / Waddington	34	38	48	39	37	55	24	0	-	-	-	-	276
Dominion / Transco Leidy	36	43	53	45	46	18	2	2	2	2	2	2	255
Everett	-	86	258	156	-	-	-	-	-	-	-	-	500
LNG Vapor	16	17	222	100	17	16	17	16	17	17	16	17	488
LNG Truck	-	-	-	-	192	71	74	71	5	5	53	17	488
City Gate	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	130	561	1,055	832	562	160	117	90	24	24	71	36	3,662
Total Purchases	2,806	4,285	5,277	4,614	4,120	2,459	1,677	1,336	849	1,107	1,320	2,093	31,941
LESS:													
Liquefaction	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG Truck	-	-	-	-	192	71	74	71	5	5	53	17	488
AGT Storage Refill	-	-	-	-	-	199	256	247	205	254	230	221	1,611
TGP Storage Refill	-	-	-	-	-	11	166	262	24	209	249	252	1,172
Total	-	-	-	-	192	281	495	581	233	467	532	490	3,271
Total Sendout	2,806	4,285	5,277	4,614	3,927	2,178	1,182	755	615	640	788	1,603	28,670
Datacheck	2,806	4,285	5,277	4,614	3,927	2,178	1,182	755	615	640	788	1,603	28,670
Delta	-	-	-	-	-	-	-	-	-	-	-	-	-

Narragansett Electric Company Volume & Cost Summary Cost of Gas ($000)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
DEMAND													
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 80,442
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 80,442
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COMMODITY													
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL COMMODITY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 81,045
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 81,045
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

TOTAL DC+CC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 161,487
LESS:													
Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AGT Storage Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TGP Storage Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Liquefaction & Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 7,885
TOTAL GAS COST	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 153,603
Commodity to Sendout	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 73,161
Days/month	30	31	31	28	31	30	31	30	31	31	30	31	365
Unit Commodity Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2.552
NYMEX (06/08/20)	$2.376	$2 824	$2.961	$2.925	$2.809	$2.494	$2.461	$2.492	$2.530	$2.538	$2.521	$2.538	

National Grid Rhode Island
Design Year
Fixed + Variable + Commodity Cost per Dth per Day by Path (100% Load Factor)
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Fixed + Variable + Commodity Cost per Dth per Day by Path (100% Load Factor)
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Fixed + Variable + Commodity Cost per Dth per Day by Path (100% Load Factor)
Sales
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Fixed + Variable + Commodity Cost per Dth per Day by Path (100% Load Factor)
Sales
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Effective Fixed + Variable + Commodity Cost per Dth per Day by Path
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Effective Fixed + Variable + Commodity Cost per Dth per Day by Path
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Effective Fixed + Variable + Commodity Cost per Dth per Day by Path
Sales
Existing and Proposed Assets

Dollars per Dth per Day

Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Effective Fixed + Variable + Commodity Cost per Dth per Day by Path
Sales
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Path					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
SCC Adj FT1
Fixed Cost per Dth per Day by Contract (100% Load Factor)
Existing and Proposed Assets

Gas Year Contract	Dollars per Dth per Day 2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
SCC Adj FT1
Fixed Cost per Dth per Day by Contract (100% Load Factor)
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Contract					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Sales
Fixed Cost per Dth per Day by Contract (100% Load Factor)
Existing and Proposed Assets

Gas Year	Dollars per Dth per Day				
Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Sales
Fixed Cost per Dth per Day by Contract (100% Load Factor)
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Effective Fixed Cost per Dth per Day by Contract
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Contract					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Effective Fixed Cost per Dth per Day by Contract
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Contract					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Effective Fixed Cost per Dth per Day by Contract
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Effective Fixed Cost per Dth per Day by Contract
SCC Adj FT1
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Effective Fixed Cost per Dth per Day by Contract
Sales
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Design Year
Effective Fixed Cost per Dth per Day by Contract
Sales
Existing and Proposed Assets

	Dollars per Dth per Day				
Gas Year Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Effective Fixed Cost per Dth per Day by Contract
Sales
Existing and Proposed Assets

Gas Year Contract	Dollars per Dth per Day 2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Normal Year
Effective Fixed Cost per Dth per Day by Contract
Sales
Existing and Proposed Assets

Gas Year	Dollars per Dth per Day				
Contract	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Customer Choice Capacity Allocation Proposal
2020/21

Paths	Peak Day City Gate MDQ (Dth/day)	City Gate Contracts	Upstream	Percent of Portfolio
TGP Long Haul	29,335	TGP 1597		7.1%
TGP ConneXion	11,600	TGP 64025, TGP 64026		2.8%
Dawn via PNGTS	29,000	TGP 62930, TGP 330580	Union M12274, TCPL 60659, TCPL 58577, PNGTS 210203	7.0%
AIM	18,000	AGT 510801	MPL 214129	4.4%
TETCO CDS Long Haul	45,934	AGT 93011E	TETCO 800303	11.1%
TCO Appalachia	40,000	AGT 90107, AGT 90106, AGT 9001	TCO 31524, TCO 31523	9.7%
TCO Hanover	-			0.0%
AGT M3	18,099	AGT 93011E, AGT 90106, AGT 93401S, AGT 90107, AGT 9001		4.4%
Dracut	20,000	TGP 349449		4.8%
TETCO SCT Long Haul	2,384	AGT 93001ESC	TETCO 800156	0.6%
Niagara	1,067	TGP 39173		0.3%
Dawn via Waddington	1,000	TGP 95345	Union M12164, TCPL 42386, IGTS 50001	0.2%
Transco	1,240	AGT 90106, AGT 96004SC	Transco 9081767	0.3%
Dominion	537	AGT 96004SC		0.1%
	218,196			52.7%
Storage	37,357	TGP 10807, AGT 9W009E, AGT 9B105, AGT 933005, AGT 90106, AGT 9B105, AGT 9S100S		9.0%
	37,357			9.0%
Peaking	158,100	TGP 330581; TGP 330580; NGLNG; Exeter; DOMAC		38.2%
	158,100			38.2%
TOTAL	413,653			100.0%

National Grid Rhode Island
Customer Choice Proposed Releases
2020/21

Paths	Peak Day City Gate MDQ (Dth/day)	Contract	Release % of Design Day Quantity	Release Volume (Dth/day)	City Gate Release (Dth/day)
TGP Long Haul	29,335	TGP 1597	7.1%	5,650	5,650
TGP ConneXion	11,600	TGP 64026	2.8%	2,234	2,234
Dawn via PNGTS	29,000	PNGTS 225805	7.0%	5,586	
		TCPL 60659	7.0%	5,597	
		Union M12274	7.0%	5,597	
		TGP349449	7.0%	5,586	5,586
AIM	18,000	MPL 210615	2.2%	1,734	
		AGT 510801	4.4%	3,467	3,467
TETCO CDS Long Haul	45,934	TETCO 800303	11.1%	8,848	
		AGT 93011E	11.1%	8,848	8,848
		AGT 510985	11.1%	8,848	
TCO Appalachia	40,000	TCO 31524	9.7%	7,705	
		AGT 90106	9.7%	7,705	7,705
		AGT 510985	9.7%	7,705	
AGT M3	18,099	AGT 93011E	2.6%	2,050	2,050
		AGT 510985	4.4%	3,486	
		AGT90106	1.8%	1,436	1,436
Dracut	20,000	TGP 349449	4.8%	3,852	3,852
TETCO SCT Long Haul	2,384	TETCO 800156	0.5%	404	
		AGT 93001ESC	0.6%	459	459

Customer Choice Design Day Requirement **79,677**

National Grid Rhode Island
Customer Choice Transportation Fixed Costs
2020/21

Sales & Customer Choice	
Annual Transportation Demand ($000)	$ 66,767
Managed Capacity (Dth/day)	3,844
Annual Managed Capacity Demand ($000)	$ 549
Design Day Transportation (Dth)	218,196
Daily Demand Per Design Day Dth	$ 0.838
Sales Only	
Annual Transportation Demand ($000)	$ 53,619
Managed Capacity (Dth/day)	3,104
Annual Managed Capacity Demand ($000)	$ 443
Design Day Transportation (Dth)	175,428
Daily Demand Per Design Day Dth	$ 0.836
Customer Choice	
Annual Transportation Demand ($000)	$ 13,148
Managed Capacity (Dth/day)	740
Annual Managed Capacity Demand ($000)	$ 106
Design Day Transportation (Dth)	42,027
Daily Demand Per Design Day Dth	$ 0.849