BEFORE THE

PUBLIC UTILITIES COMMISSION

OF THE

STATE OF RHODE ISLAND

IN THE MATTER OF	**)**	
THE NARRAGANSETT ELECTRIC	**)**	**DOCKET NO. 22-20-NG**
COMPANY D/B/A RHODE ISLAND ENERGY	**)**	
2022 GAS COST RECOVERY FILING	**)**	

DIRECT TESTIMONY
OF
JEROME D. MIERZWA

ON BEHALF OF

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

September 29, 2022

EXETER
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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York, in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFG Distribution") as a Management Trainee in the Research and Statistical Services Department ("RSS"). I was promoted to Supervisor RSS in January 1987. While employed with NFG Distribution, I conducted various financial and statistical analyses related to the Company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply") rate department where my responsibilities included utility cost of service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Purchase Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFG Distribution's state annual purchased gas cost review proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter Associates, Inc. ("Exeter"). In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1, 1996, I became a principal of Exeter. Since joining Exeter, my assignments have included gas, electric, and water utility class cost of service and rate design analysis, evaluating the gas purchasing practices and policies of natural gas utilities, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and the evaluation of customer choice natural gas transportation programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have provided testimony on more than 400 occasions in proceedings before the Federal Energy Regulatory Commission ("FERC"), utility regulatory commissions in Arkansas, Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Montana, Nevada, New Hampshire, New Jersey, Ohio, Pennsylvania, South Carolina, Texas, Utah, and Virginia, as well as before the Public Utilities Commission of Rhode Island ("Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Exeter was retained by the Division of Public Utilities and Carriers ("Division") to review the Annual Gas Cost Recovery ("GCR") filing of the Narragansett

Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or "the Company"). My testimony presents the results of my review.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I presented testimony on behalf of the Division in Rhode Island Energy's 2019 GCR proceeding at Docket No. 4963, 2020 GCR proceeding at Docket No. 5066, and 2021 GCR proceeding at Docket No. 5180. I have also previously testified before this Commission in the following water utility rate proceedings:

- City of Newport, Water Division Docket Nos. 2985, 4355, 4295, and 4933;
- Providence Water Supply Board Docket Nos. 2048, 3163, 3832, 4406, 4618 and 4994;
- Kent County Water Authority Docket Nos. 2555, 3311, and 4611;
- Pawtucket Water Supply Board Docket Nos. 2674 and 3945;
- Suez Water Rhode Island, Inc. Docket No. 4800; and
- Woonsocket Water Division Docket Nos. 4320 and 4879.

Q. WHAT IS YOUR EXPERIENCE WITH RESPECT TO EVALUATING THE GAS PROCUREMENT PRACTICES OF NATURAL GAS LOCAL DISTRIBUTION COMPANIES ("LDCs") LIKE RHODE ISLAND ENERGY?

A. Over the last 32 years, I have reviewed and assessed the gas procurement practices of approximately 40 different LDCs. For many of these LDCs, I have performed gas procurement reviews on an annual basis. In total, I estimate that I have performed approximately 220 such reviews. These assessments include review of an LDC's capacity and gas supply resource portfolios. An LDC's capacity resource portfolio would generally include those resources necessary to deliver gas supplies to the LDC's distribution system (citygate) such as firm interstate pipeline transportation service, and interstate pipeline storage service. An LDC's gas supply portfolio would generally include purchase arrangements that provide for the availability of gas at interstate pipeline receipt points which are then subsequently delivered to the LDC utilizing the LDC's capacity resource portfolio. Gas withdrawn from interstate pipeline storage facilities would generally be delivered to an LDC utilizing the LDC's capacity resource portfolio. Gas supply arrangements that provide for the delivery of gas directly to an LDC's citygate would be considered combined capacity and gas supply resources, as would an LDC's on-system storage facilities, including underground storage, LNG, and propane facilities.

Q. PLEASE SUMMARIZE RHODE ISLAND ENERGY'S CURRENT GCR RATES AND THE RATES PROPOSED IN THE COMPANY'S FILING.

A. The current High Load Factor GCR is $0.5413 per therm and the current Low Load factor GCR is $0.6137 per therm. The Company is proposing an increase in the High Load Factor GCR of $0.0902 per therm to $0.6315 per therm, or 16.7%. The Company is proposing an increase in the Low Load Factor GCR of $0.0872 per therm to $0.7009 per therm, or 14.2%. An average Residential Heating customer using 845 therms per year will experience a total bill increase of approximately $227.23, or 15.0%.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

- The current design day capacity planning standard of 68 heating degree days ("HDDs") utilized by Rhode Island Energy appears to be extremely conservative, and inconsistent with the observed practices of other LDCs. I recommend that Rhode Island Energy's re-evaluate its current design day standard to determine whether a standard more consistent with the practices of other LDCs should be adopted. The Company should present its re-evaluation in its next Gas Long-Range Resource and Requirements Plan which is scheduled to be filed by June 30, 2023.
- The gas costs Rhode Island Energy incurs to meet the design peak hour demands of its customers are currently removed from the GCR and recovered through the System Pressure Factor component of the Distribution Adjustment Charge ("DAC"). Although these costs have increased significantly since the Company's 2021 GCR proceeding, the design peak hour costs the Company has proposed to remove from the GCR and recover through the DAC in this proceeding are reasonable;
- The Company should track the actual incremental variable costs it incurs to meet hourly peak demands and report those costs in its 2023 GCR and DAC filings. Should those costs be significant, those costs should be included in the DAC reconciliation process next year and removed from the GCR reconciliation process;
- My review identified no concerns with the incentive awards calculated by the Company under the Natural Gas Portfolio Management Plan ("NGPMP") or Gas Procurement Incentive Plan ("GPIP");
- As directed in the order issued in the Company's 2021 GCR proceeding, the Division has continued to monitor the Company's advance hedge purchases under the GPIP and to evaluate whether

any changes are necessary to ensure the Company will accelerate purchases when prices are low. The Division's monitoring found that no changes were necessary; and

- The Company should update its GCR rate projections in its rebuttal testimony to reflect the most recent projections of gas supply commodity prices, if doing so results in a material change in GCR rates.

Q. BEFORE CONTINUING GENERALLY DESCRIBE THE TYPES OF CUSTOMERS SERVED BY RHODE ISLAND ENERGY AND THE SERVICES PROVIDED TO THOSE CUSTOMERS.

A. Rhode Island Energy provides firm sales service to retail GCR customers. This is a bundled service under which the Company arranges for the delivery of gas supplies to its citygate to serve these customers and provides for the delivery of these arranged supplies across its distribution system to end-use customers. As such, Rhode Island Energy contracts for interstate pipeline capacity and gas supply resources to serve retail GCR customers.

Rhode Island Energy also provides unbundled transportation service. Under transportation service, end-use customers purchase their gas supplies from third-party marketers or suppliers (collectively "marketers") which arrange for the delivery of the gas supplies necessary to serve their customers to Rhode Island Energy's citygate. The Company provides for the delivery of the marketer-arranged supplies from its citygate to the end-use customer. Rhode Island Energy offers two primary types of firm transportation service — FT-1 and FT-2. Under FT-1 service, a customer's gas usage is measured on a daily basis. Under FT-2 service, a customer's gas usage is generally measured on a monthly rather than daily basis.

There are two categories of FT-1 customers - capacity assigned and capacity exempt customers. The marketers serving capacity assigned FT-1 customers receive an assignment of the Company's interstate pipeline capacity to meet a portion of their customer's gas supply requirements. The remainder of a capacity assigned FT-1 customer's requirements would be met by other capacity and gas supply resources acquired by the marketer serving the customer. The marketers serving capacity exempt FT-1 customers are not assigned any of the Company's interstate pipeline capacity resources. Marketers serving capacity assigned and capacity exempt FT-1 customers are required to deliver the gas supply requirements of their customers on a daily basis within the imbalance tolerances permitted under Rhode Island Energy's tariff.

The marketers serving FT-2 customers also receive an assignment of Rhode Island Energy's interstate pipeline firm transportation capacity to meet a portion of their customers' gas supply requirements. The marketers serving FT-2 customers would use this capacity to arrange and provide for the delivery of gas supplies to Rhode Island Energy's citygate. FT-2 marketers are also provided access to a portion of the Company's storage and peaking resources which the marketer may use to meet the daily gas supply requirements of its customers that is not met by the assigned interstate pipeline firm transportation capacity. The storage and peaking services are not directly assigned to marketers, but are managed by the Company.

In summary, Rhode Island Energy secures the interstate pipeline firm transportation capacity, storage, peaking resources, and gas supplies necessary to meet the requirements of its retail GCR sales customers, the interstate pipeline firm transportation capacity assigned to FT-1 and FT-2 marketers, and the storage and peaking requirements of FT-2 customers. These requirements are commonly referred to as Rhode Island Energy's planning load.

II. DESIGN DAY STANDARD

Q. WHAT IS A DESIGN DAY?

A. An LDC would typically plan and secure capacity and gas supply resources sufficient to meet the daily, winter season, and annual requirements of its planning load customers under extreme weather conditions. The most critical of these three planning criteria are daily requirements, as the resources available to meet winter season and annual requirements are largely a function of the resources secured to meet daily requirements. That is, for example, firm interstate pipeline transportation capacity secured to meet daily requirements would generally also be available to meet customer requirements on each day during the winter season and on a daily basis for the remainder of the year.

An LDC's design day is commonly defined by criteria such as an extreme daily average temperature, day of the week (weekday vs. weekend), and potentially other variables. The temperature criteria is frequently expressed in terms of HDDs, which are determined by subtracting the average of the daily high and low temperature from a base of 65° F. For example, a day with an average daily temperature of 5° F would have 60 HDDs.

Q. WHAT IS THE DESIGN DAY PLANNING CRITERIA USED BY RHODE ISLAND ENERGY AND HOW IS IT SELECTED?

A. The Company determines the projected design day requirements of its planning load customers based on what it refers to as a design day standard. That standard and the selection of that standard is described in the Gas Long-Range Resource and Requirements Plan for the Forecast Period 2022/23 to 2026/27 ("LRP") submitted by the Company to the Commission on June 30, 2022 in Docket No. 22-06-NG as follows:

> 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.

Q. IS THE ONCE IN 58.92 YEAR DESIGN DAY STANDARD USED BY RHODE ISLAND ENERGY CONSISTENT WITH THE STANDARDS AND PRACTICES OF OTHER LDCS?

No. The probability of occurrence of Rhode Island Energy's design day standard appears extremely conservative compared to the standards and practices of other LDCs. The probability of occurrence of the design day standard used by Rhode Island Energy is nearly once-in-60 years. Based on my experience, LDCs typically utilize a design day standard with a probability of occurrence of once-in-30 years.

Q. DO YOU HAVE SAMPLE EVIDENCE TO SUPPORT YOUR CONTENTION CONCERNING RHODE ISLAND ENERGY'S DESIGN DAY STANDARD?

A. Yes. Table 1 identifies the probability of occurrence of the design day standard utilized by each LDC in Massachusetts. As shown in Table 1, the LDCs in Massachusetts generally utilize a design day standard with a probability of occurrence of once-in-30 years. This includes the Company's former affiliate in Massachusetts, Boston Gas Company d/b/a National Grid ("NGrid MA"). NGrid MA provides service to approximately 925,000 customers.

Table 1
Probability of Occurrence of Design Day Standard
Massachusetts LDCs

LDC	**Probability of Occurrence** (Years)
Eversource Gas of Massachusetts	1-32.5
Boston Gas Company d/b/a National Grid	1-35.32
Fitchburg Gas & Electric Light Company d/b/a Unitil	1-30
Liberty Utilities d/b/a New England Gas Company	1-35
NSTAR Gas Company d/b/a Eversource Energy	1-50
The Berkshire Gas Company	1-30

Q. WHAT IS THE SOURCE OF THE INFORMATION PRESENTED IN TABLE 1?

A. LDCs in Massachusetts, which are regulated by the Massachusetts Department of Public Utilities ("DPU"), are required to file on a bi-annual basis Long-Range Forecast and Supply Plans ("F&SP"). The F&SPs are nearly identical in content and format as the LRP filed by Rhode Island Energy on June 30, 2022, which was previously discussed in my testimony. Although I am not certain, it appears that Rhode Island Energy's LRP was modeled after the F&SPs filed by its former affiliate NGrid MA. The Massachusetts F&SP proceedings are designed, as stated in NGrid MA's most recent F&SP filed in D.P.U. 20-132, to:

> …demonstrate that the Company's gas resource planning process has resulted in a reliable resource portfolio to meet the combined forecasted needs of National Grid's Massachusetts customers at the lowest possible cost (page 3).

Q. DO THE LDCS IN MASSACHUSETTS ALSO UTILIZE AN HDD DESIGN DAY STANDARD?

A. No. Gas utilities in Massachusetts utilize an Enhance Design Day ("EDD") standard. EDDs take into account windspeed along with HDDs in determining the effect of weather. An EDD is calculated as follows:

EDD = HDD x (1 + (Windspeed/100))

A day with an average temperature of 25° F degrees, or 40 HDD, and an average windspeed of 20 MPH would have 48 EDDs.

Q. EARLIER YOU INDICATED THAT RHODE ISLAND ENERGY'S DESIGN DAY STANDARD OF 68 HDD WAS BASED ON AN ANALYSIS OF WEATHER FOR THE WINTER MONTHS OF NOVEMBER THROUGH MARCH FOR THE PERIOD 1977/78 THROUGH 2016/17. ON HOW MANY OCCASSIONS SINCE THE WINTER OF 1977/78 HAVE DAYS WITH 68 OR MORE HDDS BEEN RECORDED IN THE COMPANY'S SERVICE TERRITORY?

A. None. The coldest day in Rhode Island Energy's service territory since the winter of 1977/78 was 65 HDDs, which was actually observed on two occasions (January 1981 and January 1982). Therefore, Rhode Island Energy is utilizing a day for its design day standard which is colder than the actual coldest day observed in its service territory during the period utilized to select its design day standard.

Q. EARLIER IN YOUR TESTIMONY, IN TABLE 1, YOU IDENTIFIED THE DESIGN DAY STANDARDS UTILIZED BY MASSACHUSETTS LDCS. HAVE ANY OF THESE MASSACHUSETTS LDCS EXPERIENCED DAYS WHICH WERE COLDER THAN THEIR CURRENT DESIGN DAY STANDARD?

A. Yes. While I do not have the complete actual EDD experience of each LDC identified in Table 1, I am aware that NGrid MA has actually experienced a day that was 2 EDDs colder than its design day standard. I am also aware that Liberty exceeded its design day standard on three occasions during the last 55 years, NSTAR exceeded its design day standard on two occasions during the last 60 years, Eversource Gas of Massachusetts has exceeded its design day standard on two occasions since 1967, and Berkshire exceeded its design day standard in 2016.

Q. IN YOUR EXPERIENCE, DO MOST LDCS SELECT AN EDD RATHER THAN AN HDD DESIGN DAY STANDARD?

A. No. It is my understanding that the Massachusetts DPU determined that the use of EDD weather data should be standard practice for the LDCs it regulates. Although I would note that it is not uncommon for gas utilities to use a windspeed variable in the analysis used to determine their design day standard.

Q. IN ITS SELECTION OF A DESIGN DAY STANDARD WHICH WAS PREVIOUSLY DISCUSSED IN YOUR TESTIMONY, THE COMPANY DESCRIBES A COST-BENEFIT ANALYSIS TO EVALUATE THE RESOURCES NECESSARY TO MEET DESIGN DAY DEMAND VERSUS THE COST TO CUSTOMERS EXPERIENCING SERVICE CURTAILMENTS. DO YOU HAVE ANY COMMENTS CONCERNING THIS ASPECT OF RHODE ISLAND ENERGY'S DESIGN DAY STANDARD SELECTION PROCESS?

A. Yes. The consideration of the costs associated with service curtailments in the design day standard selection process was a requirement historically imposed by the D.P.U. on Massachusetts LDCs. Although I am not certain, it appears that Rhode Island Energy adopted this consideration when it was an affiliate of NGrid MA to be consistent with the practices of its affiliate NGrid MA. I would note that the D.P.U. has abandoned its practice requiring gas utilities to consider the costs associated with service curtailments in its design day standard selection process. I would also note that based on my experience, I am aware of no jurisdiction that currently imposes this requirement. In my opinion, determining the costs associated with service curtailment requires numerous assumptions and costs can vary significantly based on those assumptions.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE DESIGN DAY STANDARD THAT RHODE ISLAND ENERGY SHOULD UTILIZE FOR CAPACITY PLANNING PURPOSES?

A. The 68 HDD design day capacity planning standard currently utilized by Rhode Island Energy appears to be extremely conservative and inconsistent with the practices of other LDCs. I recommend that the current design day standard be re-evaluated by the Company to determine whether a standard more consistent with the practices of other LDCs should be adopted. The Company should present its re-evaluation in its next Gas Long-Range Resource and Requirements Plan which is scheduled to be filed by June 30, 2023.

Q. IF RHODE ISLAND ENERGY DOES ADOPT A DESIGN DAY STANDARD WHICH IS LESS THAN 68 HDDS AND A DAY WITH HDDS IN EXCESS OF THAT STANDARD WERE TO OCCUR, HOW WOULD THE COMPANY MAINTAIN SERVICE TO ITS CUSTOMERS?

A. Rhode Island Energy would take actions similar to what other LDCs would take to maintain service if a day with HDDs in excess of their design day standard were to occur. This would include attempting to buy citygate delivered supplies and curtailing service to non-essential customers. As noted previously in my testimony, LDCs in Massachusetts have actually experienced days which were colder than their design day standard.

Q. IF RHODE ISLAND ENERGY ADOPTED A DESIGN DAY STANDARD WHICH WAS WARMER THAN ITS CURRENT 68 HDD STANDARD, HOW MUCH MONEY COULD ITS CUSTOMERS POTENTIALLY SAVE?

A. For each HDD reduction to its current design day standard of 68 HDD, I estimate that Rhode Island Energy could reduce its capacity and gas supply resources by 5,500 Dth per day. At the time I prepared this testimony, the Division had requested a supplemental response to discovery request DIV 3-

3(a) which had not yet been received. Once I have had the opportunity to review the Company's supplemental response, I will provide an estimate of the potential savings associated with adoption of a lower design day standard. These gas cost reductions would be reflected in the Company's GCR rates and/or the System Pressure Factor component of the DAC.

III. DESIGN PEAK HOUR COSTS

Q. THE GAS COSTS THAT RHODE ISLAND ENERGY INCURS TO MEET THE DESIGN PEAK HOUR PEAK DEMANDS OF ITS CUSTOMERS ARE CURRENTLY REMOVED FROM THE GCR AND RECOVERED THROUGH THE SYSTEM PRESSURE FACTOR COMPONENT OF THE DAC. PLEASE PROVIDE A HISTORY OF HOW THIS RECOVERY MECHANISM FOR DESIGN PEAK HOUR DEMAND COSTS WAS ESTABLISHED.

A. In Rhode Island Energy's 2019 GCR proceeding in Docket No. 4963, the Division expressed concerns with respect to the recovery of the costs incurred by the Company to meet design peak hour peak demands. Those concerns were as follows.

Rhode Island Energy is directly served by two interstate pipelines — Tennessee Gas Pipeline ("Tennessee") and Algonquin Gas Transmission, LLC ("Algonquin"). While the Company's firm transportation contracts with Tennessee and Algonquin specify maximum daily delivery quantities ("MDQ"), Tennessee and Algonquin may impose hourly flow restrictions under these contracts. Because the design peak hour demands of the Company's customers are greater than the limits which may be imposed by Tennessee and/or Algonquin, in Docket No. 4963 the Company proposed to acquire incremental resources to meet the design peak hour demands of its customers. The Company proposed to recover the costs associated with these incremental resources from only GCR and FT-2 transportation customers. The concern raised by the Division in Docket No. 4963 was that the additional resources acquired by the Company would be available to meet the design peak hour demands of all customers and, therefore, benefit all customers served by Rhode Island Energy including capacity assigned FT-1 and capacity exempt FT-1 customers. The Division found that it would be appropriate for FT-1 customers to contribute to the recovery of the costs associated with the incremental design peak hour demand resources. In its Order in Docket No. 4963, the Commission directed the Company to work with the Division to develop appropriate cost allocation procedures for the recovery of design peak hour demand costs.

In consultation with the Division, Rhode Island Energy made its Annual Gas DAC filing on August 3, 2020, in Docket No. 5040 proposing to recover the incremental fixed costs associated with maintaining design peak hour demand resources from all customers through the System Pressure Factor component of its DAC. In its DAC filing, the Company estimated these fixed costs to be $5.2 million for the period November 1, 2020 through October 31, 2021, and these fixed costs were removed from the GCR rates initially reflected in the Company's September 1, 2020 GCR filing in Docket No. 5066. However, Rhode Island Energy's August 3, 2020 DAC filing in Docket No. 5040 did not fully resolve the Division's concerns regarding the recovery of incremental design peak hour costs.

In the Division's September 23, 2020 memorandum to the Commission addressing Rhode Island Energy's annual DAC filing in Docket No. 5040, the Division found the Company's proposal to recover the incremental fixed costs associated with maintaining design peak hour demand resources to generally be reasonable. However, two modifications to the Company's proposal were required to fully address the Division's concerns. The Division's review of Rhode Island Energy's GCR filing in Docket No. 5066 and subsequent discussions with the Company indicated that there were additional fixed costs that would be incurred to meet design peak hour demands that should be included in the DAC. More specifically, it appeared that a share of the Company's Tennessee firm transportation contracts that provided for the delivery of gas from Everett, MA ("Everett FT contracts") to Rhode Island Energy and the fixed reservation (demand) charges associated with the gas supply contracts that would provide for the gas supplies to be delivered under the Everett FT contracts would be incurred and were necessary to meet design peak hour demands. At the time, Rhode Island Energy maintained two Everett FT contracts with a total MDQ of 25,000 Dth per day, and the Company had entered into two gas supply arrangements to fill the 25,000 Dth per day of Everett FT contract capacity. One of the gas supply contracts, which was for 20,000 Dth per day, was entered into several years ago prior to the need for Rhode Island Energy to address hourly peak demands and was scheduled to expire at the end of the winter of 2021/2022. The other gas supply contract had recently been executed. The fixed reservation charges associated with the gas supply contracts are significantly greater than the fixed demand charges associated with the Everett FT contracts. Under the

Company's initial proposal to recover design peak hour demand costs through the DAC, the fixed costs associated with the Everett FT contracts and gas supply arrangements would be recovered from FT-2 Marketers and sales customers. Absent the need to address the potential design peak hour deficiency, a share of the Everett FT contracts and gas supply arrangements would not be required to meet customer requirements. In its September 23, 2020 DAC memorandum, the Division recommended that the calculation of the DAC be revised to reflect the fixed reservation charges associated with the then recently executed Everett gas supply arrangement for 5,000 Dth per day. The Division found this appropriate since this arrangement was executed to meet design peak hour demands, and the arrangement would be unnecessary if FT-1 marketers were not assigned capacity by Rhode Island Energy. The Division also recommended that the recovery of the fixed demand charges associated with the gas supply arrangement for 20,000 Dth per day should be revisited when the contract expires if the Company executes a replacement arrangement.

The Division also recommended in its September 23, 2020 DAC memorandum that in addition to including the incremental fixed costs associated with the design peak hour demand resources in the DAC, if significant, the incremental variable costs should also be included. Since the incremental variable costs were not known at that time, the Division recommended that the Company report in its 2021 DAC filing the incremental variable costs incurred during the winter of 2020/2021. A determination could then be made whether the costs were significant and whether the actual incremental variable costs should be included in the DAC reconciliation process.

On September 28, 2020, Rhode Island Energy made a revised DAC filing in Docket No. 5040 in which the fixed gas supply reservation charges associated with the Everett gas supply arrangement for 5,000 Dth per day and the fixed demand charges associated with 5,000 Dth per day of Everett FT contract capacity were reflected in the DAC and removed from the GCR. Rhode Island Energy also made a revised GCR filing on September 28, 2020 to reflect this change. Design peak hour fixed costs included in the Company's DAC which were removed from GCR rates for the period November 1, 2020 through October 31, 2021 were revised to $8.50 million in these filings. On October 9, 2020, Rhode Island Energy again revised its GCR and DAC filings to correct an error which reduced the design peak hour demand fixed costs to $6.11 million. In its Orders in the 2020 GCR and DAC proceedings, the Commission approved the inclusion of the $6.11 million in the DAC System Pressure Factor and the removal of those costs from the GCR.

Q. DID THE COMPANY'S 2021 GCR FILING IN DOCKET NO. 5180 REFLECT THE REMOVAL OF DESIGN PEAK HOUR DEMAND COSTS CONSISTENT WITH THE APPROACH APPROVED IN DOCKET NO. 5066, AND WAS THAT APPROACH REASONABLE?

A. Yes. In its 2021 GCR filing the Company removed from the GCR the costs associated with the same capacity and gas supply resources that were removed in Docket No. 5066. The design peak hour demand costs removed from the GCR in that proceeding totaled $6.69 million.

Q. THE ORDER IN GCR DOCKET NO. 5066 DIRECTED THE COMPANY TO REVISIT WHETHER THE EVERETT GAS SUPPLY CONTRACT FOR 20,000 DTH PER DAY SHOULD BE INCLUDED IN THE SYSTEM PRESSURE FACTOR AS A DESIGN PEAK HOUR DEMAND COST WHEN THE CONTRACT EXPIRED. DID THE COMPANY FOLLOW THIS DIRECTIVE IN DOCKET NO. 5180?

A. The Everett gas supply contract for 20,000 Dth per day did not expire until the end of the 2021-2022 winter season. Therefore, the Company did not revisit this issue in Docket No. 5180. As a result, in Docket No. 5180, the Commission again directed the Company to revisit the Everett gas supply contract for 20,000 Dth/day in its 2022 GCR proceeding to determine whether the demand charges associated with that arrangement should be included in the System Pressure Factor component of the DAC. Since the Commission's Order in Docket No. 5180, the Everett gas supply contract for 5,000 Dth per day has also expired. In addition, effective November 1, 2022, the Company is moving the receipt point under its two Everett FT contracts further upstream to Dracut, MA to access more competitively priced gas supplies, and has executed a new gas supply contract for 25,000 Dth per day to fill the Dracut FT capacity. This gas supply contract replaced the previous Everett gas supply contracts for 20,000 Dth and 5,000 Dth per day. In this proceeding, the Company has removed the demand charges associated with its newly executed Dracut gas supply contracts for 25,000 Dth per day from the GCR and included those costs in the DAC.

Q. PLEASE IDENTIFY THE DESIGN PEAK HOUR DEMAND COSTS REMOVED FROM THE GCR AND INCLUDED IN THE DAC IN THIS PROCEEDING.

A. In this proceeding, the Company has removed $68.66 million from the GCR and included those costs in the System Pressure Factor component of the DAC. As discussed on page 15, lines 4 – 12 of the Gas Supply Panel's testimony, the fixed costs associated with the following assets have been removed from the GCR and included in the System Pressure Factor: (1) portable LNG; (2) the Company's firm transportation contract on Tennessee for 25,000 Dth per day having receipts previously at Everett but effective November 1, 2022 will have receipts at Dracut; (3) the citygate delivered arrangement with Algonquin; (4) LNG trucking; and (5) the Company's firm transportation contract on Algonquin with a Beverly, MA receipt point for 5,000 Dth per day.

Q. PLEASE EXPLAIN WHY DESIGN PEAK HOUR DEMAND COSTS INCREASED FROM $6.69 MILLION IN DOCKET NO. 5180 TO $68.66 MILLION IN THIS PROCEEDING.

A. As explained in greater detail in Section IV of the testimony of Company witness Paul J. Hibbard, as a result of world events, and in particular the war in Ukraine, the price of natural gas in Europe and Asia has increased significantly. This includes prices for LNG. This has caused prices for LNG to increase dramatically, including the price for LNG at the import terminals which serve New England. Rhode Island Energy purchases LNG at one of these import terminals to meet its portable LNG requirements, and the increase in the demand charges associated with these purchases are a significant contributing factor to the increase in peak hour demand costs. In addition, the Company has increased from 5,000 Dth per day to 25,000 Dth per day the amount of Tennessee Everett/Dracut firm transportation costs and related gas supply reservation charges considered to be peak hour demand costs.

Q. SHOULD THE COMMISSION APPROVE RHODE ISLAND ENERGY PROPOSED REMOVAL OF DESIGN PEAK HOUR DEMAND COSTS FROM THE GCR AND INCLUDE THOSE COSTS IN THE DAC?

A. Despite the significant increase in those costs, the Company's proposal appears reasonable and should be approved.

Q. THE ORDER IN GCR DOCKET NO. 5180 ALSO DIRECTED THE COMPANY TO REPORT WHETHER IT INCURRED ANY INCREMENTAL VARIABLE COSTS TO MEET PEAK HOUR DEMANDS DURING THE 2021-2022 WINTER SEASON. DID THE COMPANY INCUR ANY INCREMENTAL VARIABLE COSTS TO MEET PEAK HOUR DEMANDS DURING THE WINTER 2020-2021?

A. No, the Company reported that it incurred no incremental variable costs to meet peak hour demands during the 2021-2022 winter season and my review identified no such costs.

Q. SHOULD THE COMPANY REPORT WHETHER IT INCURS ANY VARIABLE COSTS TO MEET PEAK HOUR DEMANDS DURING THE WINTER OF 2022-2023 IN NEXT YEAR'S GCR AND DAC PROCEEDINGS?

A. Yes. Should those costs be significant, those costs should be included in the DAC reconciliation process next year and removed from the GCR reconciliation process.

IV. NATURAL GAS PORTFOLIO MANAGEMENT PLAN AND GAS PROCUREMENT INCENTIVE PLAN

Q. BRIEFLY DESCRIBE THE COMPANY'S NGPMP AND GPIP.

A. Under the NGPMP, the Company uses its interstate pipeline firm transportation contracts, underground storage contracts, peaking supplies, and gas supply contracts, when not required to meet GCR customer requirements to generate incremental revenue generally through off-system transactions. The Company is provided an incentive to engage in these activities under the NGPMP. The details of the NGPMP are provided in Attachment EPM-3 of the Company's GCR filing.

The GPIP is a hedging program designed to mitigate the volatility of Rhode Island Energy's natural gas costs and to encourage the Company to achieve lower-hedged commodity costs for GCR customers. The details of the GPIP are provided in Attachment EPM-1 of the Company's GCR filing.

Q. DID YOU REVIEW THE RESULTS OF THE COMPANY'S NGPMP AND GPIP?

A. Yes.

Q. DID YOUR REVIEW IDENTIFY ANY CONCERNS WITH THE INCENTIVE AWARDS CALCULATED BY THE COMPANY UNDER EACH PLAN?

A. No, it did not.

Q. IN ITS ORDER IN DOCKET NO. 5180, THE COMMISSION DIRECTED THE COMPANY TO WORK WITH THE DIVISION TO CONTINUE TO MONITOR ADVANCE HEDGE PURCHASES AND TO DETERMINE IF ANY CHANGES ARE NECESSARY AND TO ENSURE THE COMPANY WILL ACCELERATE GAS PURCHASES WHEN GAS PRICES ARE LOW. PLEASE PROVIDE A BRIEF SUMMARY AND HISTORY OF THE ISSUE CONCERNING ADVANCE HEDGE PURCHASES.

A. The purpose of the GPIP hedging program is to mitigate gas cost volatility. As explained in greater detail in Attachment EMP-1, this is accomplished by requiring the Company to purchase a portion of its gas in approximately uniform monthly increments on a mandatory basis starting 24 months prior to the month of delivery (mandatory hedges). However, the Company and the Division may agree to accelerate a portion of the mandatory hedges. In Docket No. 5066, the Division's review of Rhode Island Energy's GPIP activity indicated that the Company had adopted a policy of accelerating approximately one-third of its mandatory purchases and making those purchases all on one day two years prior to the month of delivery. The Division recommended that the Company further diversify the timing of its accelerated purchases and limit the use of accelerated purchases to a period when current NYMEX prices are lower than average historic prices. In its order in Docket No. 5066, the Commission directed the Company to work with the Division to develop a plan to diversify advance hedge purchases to ensure the Company would accelerate gas purchases when prices were low.

Q. DID THE COMPANY WORK WITH THE DIVISION TO EVALUATE DIVERSIFYING ADVANCE HEDGE PURCHASES AS DIRECTED BY THE COMMISSION IN DOCKET NO. 5066?

A. Yes. In Docket No. 5066, the Division expressed concern that Rhode Island Energy's practice of accelerated hedge purchases may be resulting in higher costs to customers than if no accelerated hedges were made. To address this uncertainty regarding the efficacy of Rhode Island Energy's hedging practices, the Division and Company reviewed other LDCs' hedging programs and analyzed the relative performance of Rhode Island Energy's hedging program against historical market prices. Regarding the historic market price analyses, the Division and Company analyzed hedge prices relative to prevailing market prices at the time the hedges were purchased (i.e., then current prices versus future or hedge prices), and hedge prices relative to settlement prices (i.e., historical futures prices versus current prices). The former analysis represented a look at the shape of the forward price curve and whether that curve is upward or downward sloping, or relatively flat. The latter analysis addressed the cost to customers for the accelerated hedges before any transaction costs. Together, those analyses indicated that whether an accelerated hedge price was above or below the prevailing market price did not increase the likelihood that the accelerated hedge price would be similarly above or below the market price of gas at the time the hedge settled. The Company also explained that it was able to achieve lower hedge prices with its accelerated purchases because the quantities purchased at specific points in time were greater than purchasing those same quantities over multiple months. Those savings are passed through to sales customers. Finally, and without getting into the specifics of other LDCs' hedging programs, aspects of which may be confidential, the Division and Company determined that the Company's accelerated hedging program was not unreasonable relative to other hedging programs that were reviewed. Therefore, in Docket No. 5180, the Company requested, and the Division agreed, that the Company's accelerated hedging practices should continue.

Q. HAS THE DIVISION CONTINUED TO MONITOR THE COMPANY'S ADVANCE HEDGE PURCHASES AND TO DETERMINE IF ANY CHANGES ARE NECESSARY TO ENSURE THE COMPANY WILL ACCELERATE PURCHASES WHEN PRICES ARE LOW?

A. Yes. A comparison of the price for Rhode Island Energy's advance hedge purchases and current NYMEX prices from the winter of 2022/2023 is presented in Table 2. As shown in Table 2, based on current NYMEX prices, as of the close of trading on September 26, 2022, the Company's sales customer will realize a significant benefit due to the Company's advance hedge purchases.

Table 2.
Comparison of Advance Hedge Purchase and NYMEX Prices
(Dth)

	Advance Purchases		**NYMEX**	**Price**	
Month	**Quantity**	**Price**	**Price**	**Benefit**	**Savings**
November 2022	900,000	$2.490	$7.212	$4.722	$4,249,800
December	1,200,000	2.620	7.460	4.840	5,808,000
January 2023	1,200,000	2.698	7.592	4.894	5,872,800
February	1,390,000	2.618	7.258	4.640	6,449,600
March	1,240,000	2.500	6.249	3.749	4,648,760
Total	5,930,000				$27,028,960

V. UPDATED COST PROJECTIONS

Q. HOW DID RHODE ISLAND ENERGY DEVELOP THE GAS SUPPLY COMMODITY COST PROJECTIONS INCLUDED IN ITS GCR FILING?

A. The proposed GCR factors are based on the New York Mercantile Exchange ("NYMEX") forward prices as of the close of trading on August 5, 2022.

Q. HAVE NYMEX PRICES CHANGED SINCE AUGUST 5, 2022?

A. Yes. NYMEX prices for the November 1, 2022 through October 31, 2023 GCR period have decreased somewhat since August 5, 2022. For example, as of August 5, 2022, the average NYMEX price for the winter of 2022/2023 was $7.81 per Dth. Currently, as of the close of trading on September 26, 2022, the average NYMEX price for the winter of 2022/2023 is $7.15 per Dth. Therefore, the Division recommends that the Company update its GCR rate projections in its rebuttal testimony to reflect the most recent projections of gas supply commodity prices if doing so results in a material change in GCR rates (e.g., 5 percent). Updating the Company's GCR rate projections will assist in minimizing potential over/under collections.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.