The Narragansett Electric Company
d/b/a National Grid

2021 GAS COST RECOVERY

Testimony and Attachments of:

Gas Supply Panel,
Ryan M. Scheib, and
Gas Load Forecasting

REDACTED

September 1, 2021

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 5180

Submitted by:
nationalgrid

Filing Letter
& Motion

nationalgrid

Raquel J. Webster
Senior Counsel

September 1, 2021

BY HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888 508

RE: Docket 5180 – 2021 Gas Cost Recovery Filing

Dear Ms. Massaro:

I have attached an electronic version of National Grid's[1] annual Gas Cost Recovery ("GCR") filing, which the Company is submitting pursuant to the Gas Cost Recovery Clause in National Grid's gas tariff, R.I.P.U.C. NG-GAS No. 101, Section 2, Schedule A. The GCR filing reflects the customer class-specific factors necessary to provide National Grid sufficient revenue to recover projected gas costs for the period November 1, 2021 through October 31, 2022. The Company is submitting this filing provisionally to afford sufficient notice to the public of the GCR factors that had been calculated based upon assumptions that no longer hold true due to subsequent events explained below.

After the close of business[2] on August 31, 2021, the Federal Energy Regulatory Commission ("FERC") issued an Order Rejecting Tariff Records and Directing to Show Cause (the "FERC Order") in a pending matter concerning a substantial rate increase that had been proposed by Texas Eastern Transmission, LP ("TETCO"). TETCO's July 30, 2021 FERC filing was submitted just over a year after the April 1, 2020 effective date of the settlement resolving its previous rate case. On August 11, 2021, the Company filed a protest and request for evidentiary hearing in the FERC docket. The Company prepared its GCR testimony and associated exhibits and schedules anticipating that FERC would issue an order suspending the proposed rates for the maximum period of five months and that the new rates would take effect February 1, 2022, subject to refund based on the outcome of the case. As a result of the FERC Order, TETCO's proposed rate increase will not take effect as anticipated. It is unclear at this time whether TETCO will refile or seek rehearing of the FERCs Order.

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

[2] National Grid received notice of the FERCs Order at 7:45 PM on August 31, 2021 after this GCR filing had been finalized and sent for printing. Due to this late development, National Grid halted production of hard copies of this filing while it assessed how best to proceed. Through consultation with the Rhode Island Public Utilities Commission's ("PUC") counsel, National Grid determined that it would submit the GCR filing as initially prepared and revise or amend its filing once necessary adjustments are made to the GCR schedules necessary to reflect the FERC Order. Consequently, the Company will submit hard copies of this filing to the PUC on September 2, 2021.

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The Company is currently assessing the impact of the FERC Order on the GCR. At a minimum, the FERC Order will have a significant impact on the testimony and schedules concerning National Grid's gas supply planning for the coming year and the resulting increase in costs to be recovered. The FERC Order will result in a reduction of the proposed GCR factors and resulting projected customer bill impacts from the proposed GCR factors as set forth in this provisional filing. National Grid will, therefore, revise this filing with revised testimony and schedules once appropriate adjustments can be made to account for the impact of the FERC Order.

Subject to the anticipated changes explained above, this initial filing includes the pre-filed testimony and attachments of the following witnesses: Elizabeth D. Arangio, Megan J. Borst and Samara A. Jaffe (Gas Supply Panel); Ryan M. Scheib; Theodore E. Poe, Jr. and Shira Horowitz; and John M. Protano. The Gas Supply Panel testimony provides support for the estimated gas costs and items relating to the Company's proposed 2021-22 GCR factors. In addition, the Gas Supply Panel testimony describes modifications that the Company has made to its portfolio for the 2021-22 GCR period.

Similarly, subject to anticipated changes explained above, in his testimony, Mr. Scheib calculates the GCR factors proposed for effect on November 1, 2021 for the following services: (1) firm sales service to customers in the Residential Non-Heating and Heating rate classes and firm sales customers in the Small, Medium, Large, and Extra-Large Commercial and Industrial ("C&I") rate classes; and (2) transportation services provided to Gas Marketers and the associated Gas Marketer Fixed Charges and factors.

In their testimony, Mr. Poe and Ms. Horowitz provide support for the underlying retail and wholesale forecasts of natural gas customer requirements that are used to estimate gas costs in the Company's Gas Cost Recovery submission.[3]

Finally, in his testimony, Mr. Protano describes the results of the Gas Procurement Incentive Plan ("GPIP") and the Natural Gas Portfolio Management Plan ("NGPMP") for the period April 1, 2020 through March 31, 2021. He also provides an exhibit that illustrates the impact of current financial hedges for the upcoming period of November 2021 through October 2022 in the GPIP.[4]

As described in Mr. Scheib's testimony, based on the GCR factors proposed for effect November 1, 2021through October 31, 2022, an average residential heating customer using 845 therms per year would have seen a total annual bill of $1,478.21 based on the proposed GCR and DAC factors, which is an increase of $109.85, or 8.0 percent, from last year's bills. This overall increase is comprised of an increase of $64.30 as a result of the proposed GCR factors; an

[3] National Grid does not anticipate that there will be any changes to the forecast contained in the testimony of Mr. Poe and Ms. Horowitz as a result of the FERC Order.

[4] The Company is assessing the impact, if any, of the FERC Order on Mr. Protano's testimony and accompanying schedules.

increase of $42.25 as a result of the proposed DAC factors as revised in a supplemental filing on September 1, 2021 in Docket No. 5165; and an increase of $3.30 in Gross Earnings Tax.

This filing also contains a Request for Protective Treatment of Confidential Information in accordance with Rule 810-RICR-00-00-1.3(H) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure certain confidential gas-cost pricing information and commercial contract terms which are provided in Attachment GSP-1 to the pre-filed joint direct testimony of the Gas Supply Panel and Attachments RMS-1, RMS-2 and RMS-5 to the pre-filed direct testimony of Mr. Scheib.

Accordingly, National Grid has provided the PUC with two complete unredacted copies of the confidential materials in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release,"** and has included redacted copies of the materials for the public filing.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 5180 Service List
Leo Wold, Esq.
John Bell, Division
Al Mancini, Division (w/confidential Excel files via Egress Switch)
Jerome D. Mierzwa, Division Consultant (w/confidential Excel files via Egress Switch)

STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2021	)	Docket No. 5180

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID 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 810-RICR-00-00-1.3(H) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). The Company also respectfully 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 September 1, 2021, the Company submitted its 2021 Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. The GCR filing includes confidential gas cost pricing information, contract terms and counter-party identities which are provided in (1) Attachment GSP-1 to the pre-filed joint direct testimony of the Elizabeth D. Arangio, Megan J. Borst and Samara A. Jaffe, referred to as the Gas Supply Panel; (2) Attachments RMS-1,

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

RMS-2, and RMS-5 to the pre-filed direct testimony of Ryan M. Scheib; and (3) Attachment JMP-4 to the pre-filed direct testimony of John M. Protano.[2] In accordance with Rule 1.3(H)(3), National Grid has provided a redacted public version of the GCR filing and an unredacted, confidential version.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the gas cost pricing information, contract terms and counter-party identities contained in the following: (1) Attachment GSP-1 to the pre-filed joint direct testimony of the Gas Supply Panel; and (2) Attachments RMS/MJP-1, RMS/MJP-2, and RMS/MJP-5 to the pre-filed joint direct testimony of Messrs. Scheib and Pini.

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:

[2] Attachment JMP-4 consists of the Company's Natural Gas Portfolio Management Plan report for the period from April 1, 2020 to March 31, 2021. This report was filed with the PUC on June 2, 2021 subject to a separate motion for protective treatment.

> 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, confidential contract terms and counter-party identities – which are provided in Attachment GSP-1 to the Gas Supply Panel testimony, and Attachments RMS-1, RMS-2, and RMS-5 to the pre-filed direct testimony of Mr. Scheib – 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 (Bar #9064)
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Dated: September 1, 2021

Testimony of
Gas Supply Panel

JOINT DIRECT TESTIMONY

OF

GAS SUPPLY PANEL

Table of Contents

I. Introduction

Q. Please identify the members of the Gas Supply Panel.

A. The Gas Supply Panel ("Panel") consists of Elizabeth D. Arangio, Megan J. Borst, and Samara A. Jaffe.

Elizabeth D. Arangio

Q. Ms. Arangio, please state your name and business address.

A. My name is Elizabeth Danehy Arangio. My business address is National Grid, 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am the Director of Gas Supply Planning for National Grid USA Service Company, Inc ("National Grid USA"). In this position, I am responsible for overseeing the resource portfolio of The Narragansett Electric Company d/b/a National Grid (the "Company"). In addition, I am responsible for gas supply planning for the resource portfolios of National Grid's New York and Massachusetts subsidiaries. I also manage National Grid's gas Customer Choice programs. In this testimony, references to the "Company" relate solely to The Narragansett Electric Company.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Arts in Business Administration. In 1995, I graduated from Bentley College with a Master of Business Administration.

From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services. In this role, I was responsible for managing all activities associated with the Customer Choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services. In this role, I was responsible for the administration of the gas-resource portfolio and Customer Choice program in Massachusetts and, as of 2000, the resource portfolio of EnergyNorth Natural Gas, Inc., in New Hampshire. In February 2004, I assumed the additional responsibility of gas supply planning for the former KeySpan Corporation's New York and Long Island resource portfolios. Following the acquisition of KeySpan Corporation by National Grid plc, I assumed the added responsibility for the gas resource portfolios in upstate New York and Rhode Island. In August 2018, I assumed the added responsibility for all of National Grid's gas Customer Choice programs.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Northeast Gas Association and the New England-Canada Business Council.

Q. Have you previously testified before the PUC or any other regulatory commissions?

A. Yes. I have testified before the PUC on numerous occasions, most recently in support of the Company's 2020 Gas Cost Recovery ("GCR") filing in Docket No. 5066. I have also testified before the Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission, and the State of New York Department of Public Service.

<u>Megan J. Borst</u>

Q. Ms. Borst, please state your name and business address.

A. My name is Megan J. Borst. My business address is National Grid, 100 East Old Country Road, Hicksville, New York 11801.

Q. Please describe your business position and responsibilities.

A. I am a Lead Planner in the Gas Supply Planning group for National Grid USA. In this capacity, I am responsible for gas supply planning activities for The Narragansett Electric Company's gas supply resource portfolio. I am also responsible for gas supply planning activities for the gas resource portfolio of National Grid's upstate New York subsidiary.

Q. Please summarize your educational background and professional experience.

A. I graduated from Adelphi University in 2007 with a Bachelor of Science in Mathematics and a Minor in Business. In 2009, I graduated from Dowling College with a Master of Business Administration. From 2006 to 2008, I worked as intern in KeySpan's Risk Management Group and then as an intern on the Gas Scheduling team whereupon I was hired as a full-time employee in June 2007. Following National Grid's acquisition of KeySpan, I was a Scheduler with responsibilities for all of National Grid's portfolios. In 2011, I joined the Gas Supply Planning group as a Planner, and have since been promoted to Lead Planner with responsibilities for the Narragansett Electric Company and Niagara Mohawk portfolios. In this proceeding, I am testifying on behalf of The Narragansett Electric Company.

Q. Have you previously testified in regulatory proceedings?

A. No.

<u>Samara A. Jaffe</u>

Q. Ms. Jaffe, please state your name and business address.

A. My name is Samara A. Jaffe. My business address is National Grid, 100 East Old Country Road, Hicksville, NY 11801.

Q. Please state your business position and responsibilities.

A. I am the Director of Gas Contracting, Compliance and Hedging for National Grid USA. In this position, I am responsible for the acquisition of long-term gas supply and pipeline capacity; gas contract management; intervention in proceedings before the Federal Energy Regulatory Commission ("FERC"); and compliance with FERC regulations in connection with National Grid's gas trading activities for National Grid's gas distribution companies in Massachusetts, Rhode Island, and New York and oversight of the Company's Hedging program. In this proceeding, I am providing testimony on behalf of The Narragansett Electric Company with respect to gas contracts activity.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the State University of New York at Buffalo in 2006 with a Bachelor of Arts degree in Chemistry. In 2012, I graduated from Touro Law Center with a Juris Doctor. In 2016, I graduated from Dowling Institute with a Master of Business Administration. I joined KeySpan in 2007 as a Natural Gas Scheduler with responsibility for scheduling natural gas on interstate pipelines utilized by the Company to meet the requirements of its wholesale firm gas customers. After graduating from Touro Law Center in 2012, I accepted the role of Program Manager for my group and was promoted to Director in April of 2021.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I most recently testified before the PUC in support of the Company's 2020 GCR filing in Docket No. 5066. I have also testified numerous times before the Massachusetts Department of Public Utilities on behalf of Boston Gas.

Q. What is the purpose of your joint testimony in this proceeding?

A. Our testimony provides support for the estimated gas costs, and items relating to the Company's proposed 2021-22 GCR factors. In addition, our testimony discusses modifications that the Company has made to its portfolio for the 2021-22 GCR period.

Q. Are you sponsoring attachments to your testimony?

A. Yes. We are sponsoring the following attachments that accompany our testimony:

Attachment GSP-1	Projected Gas Costs – **CONFIDENTIAL Information**
Attachment GSP-2	NYMEX Strip Comparison & Forward Curves
Attachment GSP-3	Rule Curves
Attachment GSP-4	RFPs for PXP
Attachment GSP-5	RFP for AMA Dawn Waddington to Zone 6
Attachment GSP-6	RFP for AMA Dracut to Citygate
Attachment GSP-7	RFP for AMA Columbia Gas Transmission ("TCo")
Attachment GSP-8	RFP for AMA Millennium Pipeline to Ramapo
Attachment GSP-9	RFP for Everett Supply

II. Projected Gas Costs

Q. What commodity prices were used to develop the proposed GCR factors?

A. The proposed GCR factors are based on the New York Mercantile Exchange ("NYMEX") forward curve as of the close of trading on August 3, 2021. The NYMEX forward curve, which represents the current value of natural gas at the Henry Hub for delivery in the future, is the baseline price assumption for the GCR. The Company then adjusts this baseline with regional basis forward curves as of August 3, 2021 to estimate prices at the locations at which it expects to purchase gas supplies. The GCR factors also reflect underground storage and liquefied natural gas ("LNG") inventory costs as of August 1, 2021 and the projected cost of purchasing gas through the remainder of the underground and LNG injection season. Attachment GSP-1 page 1 of 17 provides a summary of gas costs by major cost categories; pages 2 of 17 through 13 of 17 shows the cost detail by supply source.

Q. How does the NYMEX forward curve referenced in the GCR year compare to last year's forward curve?

A. Attachment GSP-2 compares NYMEX pricing from August 6, 2020 utilized in last year's GCR filing to NYMEX pricing from August 3, 2021 used in this current filing. On average, the August 3, 2021 NYMEX strip is $1.183, or 40.2 percent, higher compared to the August 6, 2020 NYMEX strip during the peak season of November through March.

During the off-peak season of April through October, the August 3, 2021 NYMEX strip is on average $0.625, or 23.4 percent, higher compared to the August 6, 2020 NYMEX strip. Overall, the August 3, 2021 NYMEX strip is an average of $0.858, or 30.8 percent, higher compared to the August 6, 2020 NYMEX strip.

Q. What normal heating season and normal year load is the Company planning for in 2021-22 as compared to last year's volumes?

A. A comparison of the normal heating season and normal year load forecasts for 2020-21 and 2021-22 is provided in the table below.

2020/2021 and 2021/2022 Normal Forecast Comparison

Normal Heating Season (November - March)	2020/21 Forecast	2021/22 Forecast	Delta	Delta %
Total Normal Heating Season (Sales + Transportation)	25,505,086	26,011,254	506,167	2.0%
Normal Heating Season - Sales	20,908,961	21,409,531	500,570	2.4%
Normal Heating Season - Transportation	4,596,125	4,601,723	5,598	0.1%

Normal Year	2020/21 Forecast	2021/22 Forecast	Delta	Delta %
Total Normal Year (Sales + Transportation)	36,152,015	36,469,985	317,970	0.9%
Normal Year - Sales	28,669,989	29,229,975	559,987	2.0%
Normal Year - Transportation	7,482,026	7,240,009	(242,017)	-3.2%

The forecast filed in Docket No. 5066 against this year's forecast.
Volumes include only customers utilizing Company assets.
Volume are in dekatherms (Dth)

Q. What design day, design heating season and design year load is the Company planning for in 2021-22 as compared to last year's volumes?

A. While the GCR factors are based on customer requirements assuming normal weather, a comparison of the design day, design heating season and design year load forecasts for 2020-21 and 2021-22 is provided in the table below.

2020/2021 and 2021/2022 Design Forecast Comparison

Design Day	2020/21 Forecast	2021/22 Forecast	Delta	Delta %
Total Design Day (Sales + Transportation)	383,384	393,077	9,692	2.5%
Design Day - Sales	326,920	334,030	7,110	2.2%
Design Day - Transportation	56,464	59,046	2,582	4.6%

Design Heating Season (November - March)	2020/21 Forecast	2021/22 Forecast	Delta	Delta %
Total Design Heating Season (Sales + Transportation)	29,490,075	30,148,659	658,584	2.2%
Design Heating Season - Sales	24,373,987	24,949,968	575,981	2.4%
Design Heating Season - Transportation	5,116,088	5,198,691	82,603	1.6%

Design Year	2020/21 Forecast	2021/22 Forecast	Delta	Delta %
Total Design Year (Sales + Transportation)	40,914,912	41,406,253	491,341	1.2%
Design Year - Sales	32,767,167	33,417,434	650,268	2.0%
Design Year - Transportation	8,147,745	7,988,819	(158,926)	-2.0%

The forecast filed in Docket No. 5066 against this year's forecast.
Volumes include only customers utilizing Company assets.
Volume are in dekatherms (Dth)

Q. Did the Company perform a cold snap analysis for the 2021-22 winter season?

A. Yes. As part of its annual portfolio planning process, the Company reviewed a cold snap scenario and design day and design year scenarios for the upcoming winter season. The cold snap analysis is set forth in the Company's Long-Range Resource and Requirements Plan for the Forecast Period 2021/22 to 2025/26 dated June 30, 2021 (Docket No. 5043) (the "LRP").

Q. In addition to planning for design day, design year and cold snap requirements, is the Company continuing to plan to meet forecast peak hour requirements?

A. Yes. The Company will continue planning for forecast peak hour requirements in addition to design day, design year and cold snap requirements.

Q. How does the Company determine peak hour requirements?

A. Once the design day sendout requirement for all firm customers[1] 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 zonal (i.e., zip code) forecast. The

[1] This design day requirement reflects total firm load, including FT-1 capacity exempt design day load and the FT-1 capacity eligible storage and peaking design day load.

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.

Q. How are projected gas costs calculated?

A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT® model to perform a dispatch optimization of the portfolio of gas supply, pipeline transportation, underground storage, and peaking supplies. SENDOUT® allows the Company to determine the optimal dispatch of its existing resources subject to contractual and operating constraints to minimize the cost of supply over the year. The pricing of various pipeline services is based directly on the pipeline tariffs and the rates in effect as of August 1, 2021. The pricing of gas supplies is based on the 8/3/21 NYMEX forward curve and regional basis curves, also from 8/3/21 as described above.

Q. How did the Company categorize the projected gas cost components?

A. For the purpose of this filing, gas costs are disaggregated into two components: (1) Fixed Costs, and (2) Variable Costs. Fixed Costs include all fixed costs related to the purchase, storage, or delivery of firm gas, including pipeline and supplier fixed reservation costs and demand charges. The Company will incur Supply Fixed Cost Components in consideration of a right, but not the obligation, to call on transportation and/or supply needed to meet customers' supply requirements.

Variable Costs include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expenses incurred to transport supplies, transportation fees, storage commodity costs, taxes on storage commodity and other gas storage expense incurred to transport supplies, and inventory commodity costs.

A summary of gas costs included in the GCR and disaggregated into these cost components by month for the period November 2021 through October 2022 is shown in Attachment GSP-1 page 1 of 17.

Q. Please describe Attachment GSP-1, Pages 2 through 17.

A. Attachment GSP-1 includes the following information:

- Pages 2 through 12: show the supporting detail for gas costs included in this filing for the period November 2021 through October 2022;
    - Pages 2 through 4: show a summary of volumes and costs by supply path;
    - Pages 5 through 6: show the detail pertaining to Commodity costs listed by supply source;

- Pages 7 through 10: show the variable and fixed costs detail for transportation and storage;
- Page 11: includes the detail supporting the supplier fixed costs;
- Page 12: shows the fixed costs attributable to hourly peaking needs;

- Page 13: includes a summary of the projected underground storage and LNG inventories;
- Pages 14 through 17: show the optimized, forecasted sendout by supply source under normal weather conditions from the SENDOUT® model and the detailed makeup of supply by pipeline source, storage contract, and peaking facility/contract;
  - Pages 14 through 15: show the forecasted volumes at the receipt or purchase point;
  - Pages 16 through 17: show the forecasted volumes at the point of delivery after all pipeline fuel is accounted for; and

The pricing included in this filing reflects actual pricing and indicative pricing and terms based on the Company's current contracts with suppliers. To comply with confidentiality terms in the Company's agreements with suppliers, charges for the supply contracts have been redacted in the public version of the filing.

Q. Please describe the Company's process for calculating fixed costs associated with peak hour requirements.

A. The Company has identified the various contracts needed to support peak hour demand that is in excess of peak day demand. While all contracts are required to meet total peak hour demand, the fixed costs associated with the following assets have been specifically allocated to the peak hour; (1) portable LNG; (2) a portion of the Company's transportation contract on Tennessee with a receipt point of Everett, MA; (3) citygate delivered arrangement on Algonquin; and (4) LNG trucking. The fixed costs of these assets will be incorporated into the System Pressure Factor calculations and will be charged to all customers through the DAC (as discussed further in the Direct Testimony of Ryan Scheib).

Q. Please describe the Company's process for calculating variable costs associated with peak hour requirements.

A. As a result of discussions with the Division in 2020, the Company intends to include the 2021/22 incremental variable costs associated with the peak hour resources in the DAC reconciliation if these costs are significant. As was the case for 2020/21, the Company will track the volumes and variable costs of these resources when they are dispatched to meet the hourly requirements of the Company's customers and will work with the Division after the winter to determine whether they are significant enough to include in the DAC reconciliation. The Company is not proposing to include any variable costs associated with 2020/21 supplies in the 2021/22 DAC reconciliation as no supplies were dispatched to specifically meet peak hour requirements during the 2020/21 winter season.

Q. How do the gas costs presented in the Company's Gas Cost Recovery filing compare with those submitted to the Division in the Company's Long-Range Plan filed in Docket No. 5043?

A. Total gas costs are $21.6 million higher in this GCR filing compared with the costs forecasted in the Company's LRP. The differences are summarized in the following table:

Cost Item	Difference in $ Millions (GCR value – LRP value)
a. Fixed Costs	$3.58
b. Fixed Cost Credits	$2.14
c. Net Fixed Costs (a-b)	$1.44
d. Variable Costs	$20.17
e. NGPMP Credit	$0.00
f. Total Gas Costs (c+d-e)	$21.61

Q. Please summarize major drivers for the differences in costs between the 2021 LRP (Docket No. 5043) and this 2021 GCR.

A. Total gas costs increased by $21.61 million between the 2021 LRP and this 2021 GCR filing.

Fixed costs increased by $1.44 million. This increase is driven primarily by an increase in supplier demand charges and Texas Eastern's proposed rate increases, further discussed below. This increase was offset by fixed cost credits of $2.14 million that were not included in the LRP. The Company now estimates the fixed costs credits and hourly fixed cost credit to be $1.5 million and $6.7 million, respectively.

Total variable costs increased by $20.41 million from the 2021 LRP to the 2021 GCR due primarily to an increase in gas commodity costs. This is largely the result of an increase in forward prices; the average November 2021 through March 2022 NYMEX forward curve increased by $0.83 per dekatherm or 25% and by $0.66 per dekatherm or 22% over the full 2021/22 gas year.

Q. Please describe the impact of any pending rate proceedings impacting the Company's transportation and/or storage providers.

A. On July 31, 2020, Columbia Gas Transmission, LLC ("TCo") filed a rate increase request with the FERC. This is TCo's first rate increase request since 1995 and, since then, TCo has made substantial capital investments in modernizing its pipeline system. TCo's proposed rates, if approved, represent a 78% increase for transportation service rates and an increase of 134% for storage service rates. The proposed rates took effect February 1, 2021, subject to refund pending the outcome of settlement negotiations between TCo and intervening shippers, including the Company. A settlement in principle has been reached in the docket; however, it has not been memorialized in the docket. Once such settlement has been filed with the FERC and the rates are publicly known, the Company will make necessary adjustments to the applicable rates for TCo services.

On July 30, 2021, Texas Eastern Transmission, LP ("TETCO") filed for a rate increase with the FERC. TETCO's filing is submitted just over a year after the April 1, 2020 effective date of the settlement resolving its previous rate case in FERC Docket No. RP19-343, which resulted in a significant increase in rates and translate to a 76.6 percent increase for transportation service reservation rates under Rate Schedule FT-1 for M1-M3 service, a 75.2 percent increase for transportation service reservation rates under Rate Schedule CDS for M1-M3 service and a 48.2 percent increase to the Rate Schedule SS-1 storage reservation rate. On August 11, 2021, the Company filed a protest and request for evidentiary hearing in the docket as part of The Northeast Customer Group. The Company anticipates that FERC will issue an order suspending the proposed rates for the maximum period of five months and that the new rates will take effect February 1, 2022, subject to a refund based on the outcome of the case.

On August 17, 2021 Eastern Gas Transmission and Storage ("EGTS") held an informational session on the pipeline's plans for filing a Section 4 rate case with the

FERC on September 30, 2021, and this will be the pipeline’s first time doing so since 1997. Based on the information the pipeline provided to all customers at the informational session, the Company anticipates that the proposed rate increase will reflect the pipeline's operating cost changes, investments in infrastructure and increased risk profile.

In addition to the pending rate changes, the Company has updated the rates for storage service on NGLNG to use the settlement rates that took effect in June 2021; these rates reflect an increase of approximately $1.5 million dollars per year as compared to those included in last years’ GCR.

III. <u>Gas Supply Portfolio</u>

Q. Have there been any significant changes to the way the Company purchases gas?

A. The Company’s portfolio continues to be well positioned to take advantage of opportunities presented by the development of the Marcellus basin utilizing its economically-priced market area transportation on existing long and short-haul capacity. On most days, the Company is able to purchase less expensive supplies at the TETCO Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company’s citygates on the Algonquin pipeline, as well as the Tennessee pipeline, Zone 4 point, using existing pipeline contracts previously used to purchase Gulf of Mexico supplies.

The Company can take advantage of these less expensive supplies without incurring any additional fixed costs while still maintaining optionality to reach back to the Gulf basin should economics or reliability dictate it is prudent to do so. Additionally, the Portland Natural Gas Transmission System ("PNGTS") expansion was fully phased in as of November 2021, which increased the Company's position back to Dawn, Ontario to feed a significant portion of its TGP capacity and mitigate its historical exposure at Dracut.

Q. Have there been any changes and/or additions to the Company's capacity portfolio since last year that should be noted?

A. Yes. Each of the changes to the Company's transportation capacity portfolio is further described below. Where fixed and variable costs and credits of the below assets are reasonably known, the Company has included them in this GCR filing; where fixed and variable costs are not known, the Company has included estimates based on historical information or indicative pricing from the market.

<u>NGLNG</u>

The Company previously entered into a precedent agreement for a term of 20 years for liquefaction services at NGLNG's currently-existing storage facilities located in Providence, Rhode Island. On October 17, 2018, FERC issued the Order granting a certificate of public convenience and necessity to National Grid LNG LLC in FERC

Docket No. CP16-121-000 for the Fields Point Liquefaction Project. NGLNG filed its acceptance of the certificate of public convenience and necessity on October 29, 2018 and the Implementation Plan was filed on November 1, 2018. Based on the current timeline to construct and test the facilities, NGLNG expect to begin service of the liquefaction during October of 2022. Due to the potential mid-month in service date, for the purposes of the GCR, the Company has not assumed it will be responsible for fixed costs until November 1, 2022. Once in service, the Company will be able to utilize its existing Algonquin capacity to transport volumes to the NGLNG plant in Providence for liquefaction during the off-peak period. The LRP reflected an in-service date of September 1, 2021, as such, this has resulted in a fixed cost savings in the GCR of nearly $660,000.

<u>Northeast Energy Center, LLC (Northeast Energy)</u>

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 fifteen years, commencing upon completion of the necessary facilities. The Northeast Energy project is located in central Massachusetts and was originally expected in-service date of April 1, 2020. However, as a result of a revised scope to the permitting process and the impact of COVID-19, the project continues to await receipt of the necessary authorization to commence construction. Based on the current timeline in which Northeast Energy anticipates receipt of its necessary permits, the facility is now expected to be in service in time for the 2023 refill season. The Northeast Energy Project will interconnect with the Tennessee Gas Pipeline and allow for the Company to utilize its existing Tennessee capacity to transport volumes from liquid supply basins 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.

As a result of the delays in the NGLNG and Northeast Energy liquefaction projects, the Company has estimated the costs of LNG refill during the 2022 off-peak season based on the costs of its current arrangements.

PNGTS Capacity

The PNGTS capacity is now fully in service, allowing the Company to access up to 29,000 Dth/day from Dawn, Ontario by way of agreements with Enbridge, TransCanada, and PNGTS to deliver firm supplies into Dracut as part of the PXP Project.

In order to supply this path, the Company issued RFPs soliciting proposals for AMAs to manage both its Canadian and/or domestic transportation capacity. Through the RFP process, the Company was willing to consider AMAs that only required assignment of the Company's capacity on Enbridge and TransCanada to East Hereford and Asset

Management Arrangements ("AMA") that included a release of the Company's capacity on the downstream Portland and Tennessee assets for deliveries into the Company's Tennessee citygate. Copies of each of the RFPs are found in Attachment GSP-4. Based on the results of the RFPs, the Company will maintain the Portland and Tennessee capacity and move forward with AMAs for supplies delivered into East Hereford that will be transported by the Company to its citygates using the Company's Portland and Tennessee contracts. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned Canadian capacity for its own account. In exchange, the Company will receive an asset management fee, which is then fully credited to the customers. The Company is presently negotiating transaction confirmation(s) to memorialize these arrangements. As part of the agreement(s), the Company will reserve the right to withhold the necessary amount of capacity needed to satisfy its assignments to Marketers.

<u>Dracut Capacity</u>

For the 2021/22 heating season, the Company issued an RFP soliciting offers for an AMA to provide supply and manage its capacity from Dracut, MA to the Company's TGP city gate for a term of one year beginning November 1, 2021. The RFP contemplated a total MDQ of 15,000 Dth per day to be managed by the asset manager, after releases to Marketers were accounted for. Based on the results of the RFPs, the

Company will release the Tennessee capacity under an AMA and will have a call option at its city-gate. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then fully credited to the customers. The Company is presently negotiating a transaction confirmation to memorialize this arrangement. Please see Attachment GSP-6 for a copy of the RFP.

Incremental Winter Supplies

Beginning with the 2019/2020 heating season, the Company entered into an arrangement with Constellation LNG LLC ("Constellation") whereby the Company has the right, but not the obligation, to call on Constellation to deliver up to 14,100 Dth/day to the Company's citygates on Algonquin. These supplies are backed by firm capacity and are needed to meet forecasted design hour and design season requirements and remain available to the Company through the 2022/23 heating season.

For the 20201/22 heating season, the Company issued an RFP for a supply deal for a term of four months beginning December 2021 through March 2022. The RFP requested a maximum daily quantity ("MDQ") of 5,000 Dth/day with a maximum seasonal quantity ("MSQ") of 600,000 Dth. These supplies will be delivered directly Everett, MA to fill the

Company's Tennessee transportation that is not currently satisfied through a long-term agreement. The Company is presently negotiating a transaction confirmation to memorialize the trade. Please see Attachment GSP-9 for a copy of the RFP.

Incremental Portable LNG Storage and Vaporization Contracts

To support operations at Cumberland beginning with the 2018/2019 winter season, the Company previously entered into an equipment rental and support services agreement with Prometheus Energy Group, Inc.[2] (Stabilis Energy). The Company engaged in discussions with Stabilis regarding an extension of the original agreement and was able to negotiate an extension of the equipment and rental services agreement at Cumberland through the 2021/22 heating season.

In addition to the portable operations at Cumberland, beginning with the 2019/20 heating season, the Company has a multi-year contract for LNG storage and vaporization services at Old Mill Lane in Portsmouth with Stabilis Energy. The agreement allows the Company to access equipment and personnel sufficient to vaporize 650 Dth per hour at the injection site and, with minimal notice to Stabilis, to deploy the

[2] Prometheus Energy Group, Inc. was acquired by Stablis Energy, LLC.

contingency services. The rental and support services agreement with Stabilis Energy at Old Mill Lane is available to the Company through the 2022/23 heating season.

Incremental Winter Liquid Volumes (LNG)

To support the portable LNG storage operations at Cumberland and Old Mill Lane, the Company will need to pursue a supplemental winter-only LNG purchase agreement. The Company may also need to purchase additional winter only liquid should it be determined that the Exeter and NGLNG/Providence LNG facilities will be utilized more actively for balancing purposes during the 2021/22 winter season. Since the costs of these supplies are not yet known, the Company has used an estimate based on historical winter LNG refill deals in its GCR forecast.

Q. How will the Company supply the Dawn capacity path in Ontario, Canada to Tennessee Zone 6 via Iroquois for the 2021-22 year?

A. The Company issued an RFP for an Asset Management Arrangement for a term of one year effective November 1, 2021. The RFP requested an MDQ of 1,000 Dth/day with a monthly option for the Company to elect a baseload quantity and any remaining volumes available as a daily call option during the months of November 2021 through April 2022. These supplies will be delivered directly to the Company’s TGP city gate in Lincoln, RI by the asset manager. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to its customers. The Company is presently negotiating a transaction confirmation to memorialize the trade. Please see Attachment GSP-5 for a copy of the RFP.

Q. Will the Company be entering into an AMA using its Columbia Gas Pipeline transportation for the 2021-22 year?

A. The Company issued an RFP for an AMA for a term of one year effective November 1, 2021. The RFP requested a MDQ of 10,000 Dth/day for volumes available as a daily call option during the months of November 2021 through April 15, 2022 via the release of a portion of the Company's capacity from Broad Run to the interconnect with Algonquin at the Hanover, NJ interconnect. These supplies will be delivered directly to the interconnection between Columbia and Algonquin at Hanover by the asset manager. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to its customers. The Company is presently negotiating a transaction confirmation to memorialize the trade. Please see Attachment GSP-7 for a copy of the RFP.

Q. Will the Company be entering into an AMA using its Millennium Pipeline transportation for the 2021-22 year?

A. The Company issued an RFP for an AMA for a term of one year effective November 1, 2021. The RFP requested a MDQ of 5,000 Dth/day for volumes available as a daily call option during the months of November 2021 through April 2022 via the release of a portion of the Company's capacity from Corning-Empire PL to the interconnect with Algonquin at the Ramapo interconnect. As a result of ongoing restrictions on Texas Eastern and Algonquin that may impede operational flexibility, if the Company were to enter into an AMA resulting from this RFP, the Company determined it would not award this RFP. Please see Attachment GSP-8 for a copy of the RFP.

Q. Does this conclude your testimony?

A. Yes.

Attachments of the Gas Supply Panel

Attachment GSP-1

Redacted

Attachment GSP-1

Summary of Projected Gas Costs

REDACTED

National Grid Rhode Island
Gas Cost Recovery
Cost of Gas ($000)

Normal Weather Scenario - Sales

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
FIXED COSTS													
Total Transportation Fixed Costs	$ 4,881.2	$ 5,196.7	$ 5,192.7	$ 5,657.2	$ 5,657 2	$ 5,343.1	$ 5,343.1	$ 5,343.1	$ 5,343.1	$ 5,343.1	$ 5,343.1	$ 5,343.1	$ 63,987 0
Total Storage Delivery Fixed Costs	$ 462.0	$ 462.0	$ 462 0	$ 485.3	$ 485 3	$ 454 5	$ 454.5	$ 454 5	$ 454.5	$ 454 5	$ 454.5	$ 454.5	$ 5,537.7
Total Storage Fixed Costs	$ 574.8	$ 574.7	$ 574.7	$ 635.1	$ 635.1	$ 635.1	$ 635.1	$ 635.1	$ 635.1	$ 635.1	$ 635.1	$ 635.1	$ 7,440 5
Total Liquefaction Fixed Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supplier Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 15,423.7
LESS:													
AMA Credits	$ 125.2	$ 125.2	$ 125 2	$ 125.2	$ 125 2	$ 125 2	$ 125.2	$ 125 2	$ 125.2	$ 125 2	$ 125.2	$ 125.2	$ 1,501.864
Hourly Peaking Fixed Costs	$ 20.9	$ 1,629.5	$ 1,629 5	$ 1,629.5	$ 1,629 5	$ 20 9	$ 20.9	$ 20 9	$ 20.9	$ 20 9	$ 20.9	$ 20.9	$ 6,685 2
TOTAL FIXED COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 84,201 9
VARIABLE COSTS													
Commodity													
Commodity for Purchases to City Gate	$ 8,490.0	$ 13,023.6	$ 17,320 2	$ 14,917.6	$ 12,359 5	$ 6,112 2	$ 2,930.7	$ 1,970 5	$ 1,568.0	$ 1,565 3	$ 1,711.7	$ 3,588.7	$ 85,558 0
Commodity for Purchases to Injections	$ 13.0	$ -	$ -	$ -	$ 818 3	$ 414 9	$ 2,048.5	$ 1,043.7	$ 1,913.7	$ 1,969 8	$ 1,781.4	$ 1,741.6	$ 11,744 8
Total Commodity Costs	$ 8,503.0	$ 13,023.6	$ 17,320 2	$ 14,917.6	$ 13,177 8	$ 6,527 0	$ 4,979.2	$ 3,014 2	$ 3,481.7	$ 3,535.1	$ 3,493.1	$ 5,330.3	$ 97,302.8
Withdrawal													
Underground Storage Withdrawal Value	$ 1,006.0	$ 2,268.6	$ 2,441.6	$ 2,245.6	$ 1,482 0	$ 192.4	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,636 2
LNG Storage Withdrawal Value	$ 84.8	$ 87.8	$ 534.4	$ 398.4	$ 90.4	$ 88.6	$ 91.4	$ 88 3	$ 91.0	$ 90 9	$ 87.9	$ 90.7	$ 1,824.6
Total Storage Withdrawal Value	$ 1,090.8	$ 2,356.4	$ 2,976 0	$ 2,644.0	$ 1,572 3	$ 281 0	$ 91.4	$ 88 3	$ 91.0	$ 90 9	$ 87.9	$ 90.7	$ 11,460 8
Transportation													
Variable Costs for Purchases to City Gate	$ 207.8	$ 260.9	$ 324 5	$ 315.2	$ 285 5	$ 86 2	$ 42.6	$ 29.6	$ 55.5	$ 59.1	$ 74.9	$ 134.7	$ 1,876.7
Variable Costs for Storage Withdrawal	$ 43.5	$ 99.3	$ 101 9	$ 94.7	$ 53.6	$ 4.7	$ -	$ -	$ -	$ -	$ -	$ -	$ 397.7
Variable Costs for Storage Injection	$ 16.2	$ -	$ -	$ -	$ 132 2	$ 36.7	$ 61.7	$ 45 9	$ 80.8	$ 46.4	$ 67.2	$ 64.7	$ 551 8
Total Transportation Variable Costs	$ 241.5	$ 320.4	$ 386.7	$ 371.8	$ 462 3	$ 123.1	$ 83.4	$ 61.7	$ 115.0	$ 83.6	$ 121.8	$ 179.1	$ 2,550 5
Total Storage Variable Costs	$ 26.0	$ 39.8	$ 39.6	$ 38.1	$ 9 0	$ 4 5	$ 20.9	$ 13 9	$ 21.3	$ 21 9	$ 20.4	$ 20.3	$ 275.7
LESS:													
LNG Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,942.4
Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 254 8	$ 1,985.1	$ 963.6	$ 1,764.8	$ 2,016 2	$ 1,686.7	$ 1,682.9	$ 10,354 2
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage and Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 12,296.6
TOTAL VARIABLE COSTS	$ 9,832.1	$ 15,740.1	$ 20,722.6	$ 17,971.5	$ 14,271 0	$ 6,484.1	$ 3,064.7	$ 2,088.4	$ 1,714.6	$ 1,715.4	$ 1,874.5	$ 3,814.2	$ 99,293 2
TOTAL FIXED AND VARIABLE COSTS	$ 15,707.3	$ 23,852.1	$ 28,830 5	$ 26,627.7	$ 22,927 2	$ 12,883 3	$ 9,463.9	$ 8,487.6	$ 8,113.8	$ 8,114 5	$ 8,273.7	$ 10,213.4	$ 183,495.1
NGPMP Credit	$ 669.9	$ 669.9	$ 669 9	$ 669.9	$ 669 9	$ 669 9	$ 669.9	$ 669 9	$ 669.9	$ 669 9	$ 669.9	$ 669.9	$ 8,039 2
TOTAL GAS COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 175,455.884

REDACTED

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

Normal Weather Scenario - Sales

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
Algonquin													
TETCO CDS Long Haul	1,087	1,112	1,145	1,003	1,145	54	421	256	779	793	859	1,078	9,730
TETCO SCT Long Haul	-	8	29	26	3	-	-	-	-	-	-	-	67
AIM	223	222	234	212	227	72	223	215	222	222	215	226	2,511
AGT M3	64	28	87	44	178	1,595	722	415	-	-	6	400	3,541
TCO Appalachia	421	998	988	902	914	87	51	3	51	51	32	21	4,517
Storage	411	538	561	529	205	83	-	-	-	-	-	-	2,329
Total Algonquin	2,205	2,907	3,044	2,716	2,673	1,891	1,417	888	1,051	1,066	1,111	1,725	22,694
Tennessee													
TGP Long Haul	356	415	645	589	374	208	-	-	-	56	-	209	2,850
TGP ConneXion	194	251	293	264	248	177	279	105	225	295	286	294	2,912
Storage	25	416	462	412	398	-	-	-	-	-	-	-	1,712
Total Tennessee	574	1,081	1,400	1,265	1,019	385	279	105	225	350	286	503	7,474
Other													
Dawn via PNGTS	24	208	496	447	241	4	-	-	-	-	-	-	1,418
Dracut	-	-	-	-	-	-	174	107	-	-	76	-	357
Dawn / Niagara / Waddington	3	35	49	36	17	32	-	-	-	-	-	-	172
Dominion / Transco Leidy	26	35	53	44	43	3	19	18	19	2	18	36	315
Everett	-	89	237	175	5	-	-	-	-	-	-	-	505
LNG Vapor	19	19	118	88	19	19	19	19	19	19	19	19	398
LNG Truck	5	-	-	-	181	43	28	28	51	-	36	27	398
City Gate	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	77	385	953	790	505	100	240	172	89	22	148	83	3,565
Total Purchases	2,856	4,374	5,397	4,771	4,197	2,377	1,937	1,166	1,365	1,438	1,545	2,311	33,733
LESS:													
Liquefaction	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG Truck	5	-	-	-	181	43	28	28	51	-	36	27	398
AGT Storage Refill	-	-	-	-	-	55	472	258	536	520	472	458	2,770
TGP Storage Refill	-	-	-	-	-	33	279	105	144	266	252	255	1,334
Total	5	-	-	-	181	131	779	392	730	786	759	740	4,503
Total Sendout	2,852	4,374	5,397	4,771	4,016	2,246	1,157	774	635	652	785	1,571	29,230
Datacheck	2,852	4,374	5,397	4,771	4,016	2,246	1,157	774	635	652	785	1,571	29,230
Delta	-	-	-	-	-	-	-	-	-	-	-	-	-

REDACTED

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

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
DEMAND													
TETCO CDS Long Haul Transportation	$ 1,000	$ 1,000	$ 1,000	$ 1,456	$ 1,456	$ 1,456	$ 1,456	$ 1,456	$ 1,456	$ 1,456	$ 1,456	$ 1,456	$ *16,104*
TETCO SCT Long Haul Transportation	$ 18	$ 18	$ 18	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ *287*
AIM Transportation	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ 760	$ *9,123*
AGT M3 Transportation	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ *1,521*
TCO Appalachia Transportation	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ 703	$ *8,437*
TGP Long Haul Transportation	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ 452	$ *5,419*
TGP ConneXion Transportation	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ 216	$ *2,592*
Dawn via PNGTS Transportation	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ *13,345*
Dracut Transportation	$ 84	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ *1,019*
Dawn / Niagara / Waddington Transportation	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ *387*
Dominion / Transco Leidy Transportation	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ *204*
Manchester Lateral / Yankee Interconnect	$ 257	$ 257	$ 253	$ 253	$ 253	$ 253	$ 253	$ 253	$ 253	$ 253	$ 253	$ 253	$ *3,039*
Everett Transportation	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ *1,255*
Storage Delivery	$ 462	$ 462	$ 462	$ 485	$ 485	$ 454	$ 454	$ 454	$ 454	$ 454	$ 454	$ 454	$ *5,538*
Storage Capacity	$ 284	$ 284	$ 284	$ 345	$ 345	$ 345	$ 345	$ 345	$ 345	$ 345	$ 345	$ 345	$ *3,954*
NGLNG	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ *3,486*
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ *4,559*
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] *1,256*
Supplier Reservation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ *10,865*
Total Demand	$ 6,021	$ 9,867	$ 9,863	$ 10,411	$ 10,411	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 92,389
Datacheck	$ 6,021	$ 9,867	$ 9,863	$ 10,411	$ 10,411	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 6,545	$ 92,389
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	
COMMODITY														
TETCO CDS Long Haul	$ 3,887	$ 4,270	$ 4,548	$ 3,967	$ 4,139	$ 153	$ 1,071	$ 660	$ 2,000	$ 1,980	$ 1,947	$ 2,495	$ 31,116	
TETCO SCT Long Haul	$ -	$ 36	$ 127	$ 119	$ 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 297	
AIM	$ 792	$ 842	$ 953	$ 856	$ 827	$ 206	$ 572	$ 559	$ 576	$ 561	$ 490	$ 517	$ 7,753	
AGT M3	$ 243	$ 145	$ 628	$ 309	$ 750	$ 4,531	$ 1,891	$ 1,103	$ -	$ -	$ 14	$ 984	$ 10,597	
TCO Appalachia	$ 1,534	$ 3,814	$ 3,925	$ 3,528	$ 3,332	$ 258	$ 135	$ 7	$ 132	$ 131	$ 79	$ 53	$ 16,928	
TGP Long Haul	$ 1,329	$ 1,638	$ 2,614	$ 2,345	$ 1,424	$ 651	$ -	$ -	$ -	$ 155	$ -	$ 536	$ 9,364	
TGP ConneXion	$ 707	$ 969	$ 1,159	$ 1,029	$ 921	$ 541	$ 780	$ 297	$ 632	$ 808	$ 712	$ 736	$ 9,291	
Dawn via PNGTS	$ 99	$ 867	$ 2,106	$ 1,907	$ 992	$ 12	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,984	
Dracut	$ -	$ -	$ -	$ -	$ -	$ -	$ 463	$ 291	$ -	$ -	$ 190	$ -	$ 944	
Dawn / Niagara / Waddington	$ 12	$ 137	$ 203	$ 152	$ 66	$ 94	$ -	$ -	$ -	$ -	$ -	$ -	$ 664	
Dominion / Transco Leidy		$ 94	$ 134	$ 212	$ 174	$ 158	$ 8	$ 48	$ 47	$ 48	$ 5	$ 41	$ 86	$ 1,055
Everett	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Storage Withdrawals		$ 1,049	$ 2,368	$ 2,543	$ 2,340	$ 1,536	$ 197	$ -	$ -	$ -	$ -	$$ --	$ 10,034	
LNG Vapor	$ 85	$ 88	$ 534	$ 398	$ 90	$ 89	$ 91	$ 88	$ 91	$ 91	$ 88	$ 91	$ 1 825	
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
City Gate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
TOTAL COMMODITY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 111,590	
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 111,590	
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

REDACTED

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
TOTAL DC+CC	$ 15,883	$ 25,607	$ 30,585	$ 28,382	$ 25,632	$ 13,481	$ 11,720	$ 9,723	$10,254	$10,277	$ 10,268	$ 12,166	$ 203,979
LESS:													
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,942
AGT Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 156	$ 1,205	$ 667	$ 1,362	$ 1,287	$ 1,059	$ 1,042	$ 6,776
TGP Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 99	$ 780	$ 297	$ 403	$ 730	$ 628	$ 641	$ 3,578
Total Liquefaction & Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 12,297
TOTAL GAS COST	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 191,682
Commodity to Sendout	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 99,293
Days/month	30	31	31	28	31	30	31	30	31	31	30	31	365
Unit Commodity Cost ($/MMBtu)	$3.448	$3.599	$3 840	$3.767	$3.554	$2 887	$2.648	$2.698	$2.702	$2.630	$2.387	$2.428	$3 397
NYMEX (08/03/2021)	$4.089	$4.190	$4 256	$4.175	$3.930	$3 331	$3.244	$3.273	$3 308	$3.315	$3.301	$3 320	

REDACTED

National Grid Rhode Island
Gas Commodity Costs
Normal Year

Commodity Cost ($000)	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 31.6	$ 8.0	$ 100.8	$ 93.5	$ 31.4	$ 48.5	$ -	$ -	$ -	$ -	$ -	$ 10.8	$ 324.7
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 818.3
Dawn via IGTS	$ -	$ 20.9	$ 72.2	$ 68.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 161.2
Dawn via PNGTS	$ 98.2	$ 860.2	$ 2,089.1	$ 1,891.7	$ 984.1	$ 11.6	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,934.9
Dominion SP	$ 55.5	$ 60.9	$ 62.2	$ 55.6	$ 58.0	$ -	$ 41.5	$ 40.6	$ 41.7	$ -	$ 35.4	$ 36.6	$ 487.9
Dracut Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 932.1
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2,451.2
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Millennium	$ 748.0	$ 821.0	$ 838.6	$ 750.0	$ 782.8	$ 153.6	$ 559.2	$ 547.0	$ 562.9	$ 548.5	$ 477.8	$ 493.5	$ 7,283.0
Niagara	$ 11.9	$ 113.4	$ 126.3	$ 80.2	$ 32.2	$ 91.3	$ -	$ -	$ -	$ -	$ -	$ -	$ 455.3
TCO Appalachia	$ 1,514.0	$ 3,765.8	$ 3,877.2	$ 3,484.7	$ 3,287.9	$ 253.7	$ 133.0	$ 6.6	$ 130.6	$ 129.6	$ 78.2	$ 52.1	$ 16,713.4
Tetco M3	$ 240.6	$ 143.5	$ 623.2	$ 306.4	$ 744.3	$ 4,477.8	$ 1,867.3	$ 1,090.4	$ -	$ -	$ 13.7	$ 970.7	$ 10,477.8
Transco Leidy	$ 34.9	$ 67.0	$ 136.9	$ 108.8	$ 90.7	$ 7.8	$ 5.4	$ 5.3	$ 5.4	$ 5.2	$ 4.6	$ 42.6	$ 514.5
Waddington	$ -	$ 0.4	$ 0.9	$ 0.3	$ 32.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34.4
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 13.0
Tetco M2 CDS	$ 3,756.6	$ 4,138.1	$ 4,412.5	$ 3,825.6	$ 3,977.6	$ 148.3	$ 1,037.0	$ 638.2	$ 1,920.4	$ 1,897.7	$ 1,853.3	$ 2,369.7	$ 29,975.0
Tetco M2 SCT	$ -	$ 31.8	$ 113.3	$ 98.9	$ 11.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 255.8
TGP Z4 Cnx	$ 705.6	$ 966.2	$ 1,156.7	$ 1,027.1	$ 918.6	$ 538.6	$ 773.9	$ 293.4	$ 628.0	$ 802.7	$ 706.8	$ 731.5	$ 9,249.1
TGP Z4 LH	$ 1,293.1	$ 1,596.7	$ 2,549.7	$ 2,286.5	$ 1,386.7	$ 630.6	$ -	$ -	$ -	$ 151.4	$ -	$ 519.2	$ 10,413.9
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 807.5
Grand Total	**$ 8,503.0**	**$ 13,023.6**	**$ 17,320.2**	**$ 14,917.6**	**$ 13,177.8**	**$ 6,527.0**	**$ 4,979.2**	**$ 3,014.2**	**$ 3,481.7**	**$ 3,535.1**	**$ 3,493.1**	**$ 5,330.3**	**$ 97,302.8**

Unit Cost ($/Dth)	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Weighted Average
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 3.74	$ 4.99	$ 7.09	$ 6.83	$ 4.13	$ 2.78	$ -	$ -	$ -	$ -	$ -	$ 2.40	$ 4.81
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 4.52
Dawn via IGTS	$ -	$ 4.07	$ 4.14	$ 4.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.14
Dawn via PNGTS	$ 3.94	$ 4.07	$ 4.14	$ 4.16	$ 4.01	$ 3.19	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.11
Dominion SP	$ 3.37	$ 3.58	$ 3.66	$ 3.63	$ 3.42	$ -	$ 2.44	$ 2.47	$ 2.46	$ -	$ 2.16	$ 2.15	$ 2.93
Dracut Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.61
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 4.85
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Millennium	$ 3.37	$ 3.59	$ 3.66	$ 3.63	$ 3.42	$ 2.70	$ 2.44	$ 2.47	$ 2.46	$ 2.39	$ 2.16	$ 2.16	$ 2.88
Niagara	$ 3.68	$ 3.81	$ 3.88	$ 3.89	$ 3.75	$ 2.83	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.58
TCO Appalachia	$ 3.51	$ 3.67	$ 3.82	$ 3.77	$ 3.50	$ 2.85	$ 2.59	$ 2.59	$ 2.54	$ 2.52	$ 2.40	$ 2.43	$ 3.61
Tetco M3	$ 3.74	$ 4.99	$ 7.09	$ 6.83	$ 4.13	$ 2.78	$ 2.56	$ 2.60	$ -	$ -	$ 2.40	$ 2.40	$ 2.93
Transco Leidy	$ 3.35	$ 3.58	$ 3.65	$ 3.60	$ 3.37	$ 2.68	$ 2.38	$ 2.40	$ 2.37	$ 2.31	$ 2.09	$ 2.09	$ 3.25
Waddington	$ -	$ 4.72	$ 5.69	$ 5.59	$ 4.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.12
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2.81
Tetco M2 CDS	$ 3.36	$ 3.61	$ 3.74	$ 3.70	$ 3.38	$ 2.70	$ 2.42	$ 2.46	$ 2.42	$ 2.34	$ 2.11	$ 2.14	$ 3.00
Tetco M2 SCT	$ -	$ 3.61	$ 3.74	$ 3.71	$ 3.37	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.69
TGP Z4 Cnx	$ 3.59	$ 3.81	$ 3.90	$ 3.84	$ 3.66	$ 3.00	$ 2.76	$ 2.77	$ 2.77	$ 2.71	$ 2.46	$ 2.47	$ 3.15
TGP Z4 LH	$ 3.59	$ 3.81	$ 3.90	$ 3.84	$ 3.66	$ 3.00	$ -	$ -	$ -	$ 2.71	$ -	$ 2.47	$ 3.61
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.79
Weighted Average	**$ 3.46**	**$ 3.74**	**$ 3.98**	**$ 3.90**	**$ 3.60**	**$ 2.84**	**$ 2.57**	**$ 2.59**	**$ 2.54**	**$ 2.44**	**$ 2.24**	**$ 2.28**	**$ 3.26**

REDACTED

National Grid Rhode Island
Gas Commodity Costs
Normal Year

Commodity to Injections ($000)	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Grand Total
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 818.3
Dawn via IGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn via PNGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion SP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dracut Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Long-Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Swing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millennium	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ 3.0	$ 133.0	$ 6.6	$ 130.6	$ 129.6	$ 78.2	$ 43.6	$ 524.6
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 13.0
Tetco M2 CDS	$ -	$ -	$ -	$ -	$ -	$ 148.3	$ 1,037.0	$ 638.2	$ 1,191.1	$ 1,118.0	$ 944.3	$ 962.0	$ 6,038.9
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 Cnx	$ -	$ -	$ -	$ -	$ -	$ 98.3	$ 773.9	$ 293.4	$ 399.3	$ 570.8	$ 623.1	$ 381.5	$ 3,140.3
TGP Z4 LH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 151.4	$ -	$ 250.9	$ 402.3
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 807.5
Grand Total	**$ 13.0**	**$ -**	**$ -**	**$ -**	**$ 818.3**	**$ 414.9**	**$ 2,048.5**	**$ 1,043.7**	**$ 1,913.7**	**$ 1,969.8**	**$ 1,781.4**	**$ 1,741.6**	**$ 11,744.8**

REDACTED

National Grid Rhode Island
Transportation Variable Costs
Normal Year
($000)

Transportation Costs	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Dracut	$ 0.4	$ 6.1	$ 13.7	$ 12.4	$ 6.7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 39.2
Everett	$ -	$ 2.8	$ 7.6	$ 5.6	$ 0.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.2
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 303.7
Manchester Lateral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ 0.2	$ 2.2	$ 2.5	$ 1.6	$ 0.6	$ 2.4	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.6
Storage Delivery	$ 40.1	$ 67.3	$ 69.2	$ 61.9	$ 63.2	$ 21.5	$ 8.4	$ 3.9	$ 4.4	$ 5.9	$ 6.3	$ 11.7	$ 363.8
Yankee Interconnect	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM	$ 12.9	$ 12.8	$ 13.5	$ 12.2	$ 13.1	$ 4.1	$ 12.9	$ 12.4	$ 12.8	$ 12.8	$ 12.4	$ 13.1	$ 144.9
Transco	$ 2.8	$ 5.5	$ 11.7	$ 9.3	$ 8.2	$ 0.3	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 6.1	$ 44.5
TCO (Pool)	$ 13.0	$ 25.9	$ 25.7	$ 23.4	$ 24.6	$ 8.4	$ 6.8	$ 6.6	$ -	$ -	$ 0.2	$ 3.7	$ 138.3
TETCO SCT Long Haul	$ -	$ 3.9	$ 13.3	$ 19.0	$ 2.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38.7
AGT M3	$ 38.8	$ 50.0	$ 54.9	$ 48.0	$ 43.0	$ 32.8	$ 9.0	$ 3.0	$ 6.7	$ 5.7	$ 8.6	$ 20.1	$ 320.6
TETCO CDS Long Haul	$ 96.5	$ 97.9	$ 101.6	$ 111.8	$ 125.7	$ 4.3	$ 18.6	$ 11.1	$ 52.4	$ 55.0	$ 63.9	$ 87.7	$ 826.4
Dominion	$ 0.3	$ 0.4	$ 0.9	$ 0.6	$ 0.3	$ -	$ 0.3	$ 0.3	$ 0.3	$ -	$ 0.3	$ 0.3	$ 3.8
Dawn via Waddington	$ -	$ 0.4	$ 1.4	$ 1.3	$ 0.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.7
Dawn via PNGTS	$ 0.5	$ 1.2	$ 3.6	$ 3.1	$ 1.7	$ 0.1	$ 5.6	$ 3.4	$ -	$ -	$ 2.4	$ -	$ 21.7
TGP Long Haul	$ 18.2	$ 41.5	$ 64.7	$ 59.0	$ 37.4	$ 16.2	$ -	$ -	$ -	$ 2.5	$ -	$ 14.7	$ 254.2
TGP ConneXion	$ 1.7	$ 2.3	$ 2.6	$ 2.4	$ 2.2	$ 1.5	$ 1.3	$ 0.5	$ 1.4	$ 1.7	$ 1.5	$ 2.0	$ 21.0
Portable LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 2,550.5**

REDACTED

National Grid Rhode Island
Storage Variable Costs
Normal Year
($000)

Storage Costs	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Columbia FSS	$ 0.1	$ 0.5	$ 1.1	$ 0.8	$ 0.5	$ 0.0	$ 0.8	$ 0.0	$ 0.8	$ 0.8	$ 0.5	$ 0.3	$ 6.2
Dominion GSS	$ 0.4	$ 4.6	$ 4.8	$ 3.9	$ 2.8	$ 1.8	$ 4.8	$ 4.5	$ 4.4	$ 4.2	$ 3.8	$ 3.7	$ 43.7
Dominion GSSTE	$ 3.6	$ 3.7	$ 3.7	$ 3.3	$ 3.7	$ 1.8	$ 4.0	$ -	$ 5.8	$ 5.4	$ 5.0	$ 4.8	$ 44.7
Providence LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee FSMA	$ -	$ 1.2	$ 1.5	$ 1.5	$ 2.0	$ -	$ 1.5	$ -	$ 0.4	$ 1.5	$ 1.4	$ 1.5	$ 12.3
Tetco FSS1	$ 0.6	$ 0.8	$ 0.8	$ 0.7	$ -	$ 0.0	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 5.5
Tetco SS1	$ 21.4	$ 29.0	$ 27.8	$ 27.8	$ -	$ 0.8	$ 9.5	$ 8.9	$ 9.6	$ 9.6	$ 9.3	$ 9.6	$ 163.3
Exeter LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	**$ 26.0**	**$ 39.8**	**$ 39.6**	**$ 38.1**	**$ 9.0**	**$ 4.5**	**$ 20.9**	**$ 13.9**	**$ 21.3**	**$ 21.9**	**$ 20.4**	**$ 20.3**	**$ 275.7**

Withdrawal Value	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Columbia FSS	$ 10.1	$ 89.8	$ 183.0	$ 142.3	$ 89.1	$ 3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ 517.3
Dominion GSS	$ 63.0	$ 711.3	$ 731.8	$ 600.3	$ 428.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,535.3
Dominion GSSTE	$ 378.7	$ 391.4	$ 391.4	$ 353.6	$ 391.4	$ 189.4	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,096.0
Exeter LNG	$ 27.2	$ 28.1	$ 101.4	$ 105.2	$ 29.3	$ 28.7	$ 29.6	$ 28.5	$ 29.5	$ 29.4	$ 28.4	$ 29.3	$ 494.6
Providence LNG	$ 57.7	$ 59.7	$ 433.0	$ 293.2	$ 61.1	$ 59.9	$ 61.8	$ 59.7	$ 61.6	$ 61.5	$ 59.5	$ 61.5	$ 1,330.1
Tennessee FSMA	$ -	$ 326.2	$ 414.4	$ 428.5	$ 572.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,741.8
Tetco FSS1	$ 25.9	$ 33.6	$ 32.3	$ 32.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124.1
Tetco SS1	$ 528.3	$ 716.2	$ 688.6	$ 688.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,621.7
Grand Total	**$ 1,090.8**	**$ 2,356.4**	**$ 2,976.0**	**$ 2,644.0**	**$ 1,572.3**	**$ 281.0**	**$ 91.4**	**$ 88.3**	**$ 91.0**	**$ 90.9**	**$ 87.9**	**$ 90.7**	**$ 11,460.8**

Injection Value	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Columbia FSS	$ -	$ -	$ -	$ -	$ -	$ 3.0	$ 134.5	$ 6.7	$ 132.2	$ 131.1	$ 79.2	$ 44.2	$ 530.8
Dominion GSS	$ -	$ -	$ -	$ -	$ -	$ 199.8	$ 482.9	$ 460.4	$ 446.9	$ 412.4	$ 342.1	$ 337.7	$ 2,682.2
Dominion GSSTE	$ -	$ -	$ -	$ -	$ -	$ -	$ 374.9	$ -	$ 546.7	$ 500.1	$ 412.5	$ 408.4	$ 2,242.6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 527.6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,414.9
Tennessee FSMA	$ -	$ -	$ -	$ -	$ -	$ -	$ 468.9	$ -	$ 113.4	$ 461.5	$ 405.3	$ 422.1	$ 1,871.2
Tetco FSS1	$ -	$ -	$ -	$ -	$ -	$ 2.4	$ 23.0	$ 22.6	$ 23.0	$ 22.3	$ 19.5	$ 20.5	$ 133.4
Tetco SS1	$ -	$ -	$ -	$ -	$ -	$ 49.6	$ 500.9	$ 474.0	$ 502.7	$ 488.7	$ 428.1	$ 449.9	$ 2,893.9
Grand Total	**$ 29.2**	**$ -**	**$ -**	**$ -**	**$ 950.4**	**$ 451.6**	**$ 2,110.2**	**$ 1,089.6**	**$ 1,994.5**	**$ 2,016.2**	**$ 1,848.6**	**$ 1,806.2**	**$ 12,296.6**

REDACTED

National Grid Rhode Island
Transportation Fixed Costs
Normal Year
($000)

Transportation Costs	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Dracut	$ 83.6	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85 0	$ 1,018.9
Everett	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104.5	$ 104 5	$ 1,254.5
LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Manchester Lateral	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 209.6	$ 2,515 5
Niagara	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 80.6
Storage Delivery	$ 462 0	$ 462.0	$ 462.0	$ 485.3	$ 485.3	$ 454.5	$ 454.5	$ 454.5	$ 454.5	$ 454.5	$ 454.5	$ 454.5	$ 5,537.7
Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 523.5
AIM	$ 760 2	$ 760.2	$ 760.2	$ 760 2	$ 760.2	$ 760.2	$ 760.2	$ 760.2	$ 760.2	$ 760.2	$ 760.2	$ 760.2	$ 9,122.8
Transco	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 113.1
TCO (Pool)	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 703.1	$ 8,436.7
TETCO SCT Long Haul	$ 17 9	$ 17.9	$ 17.9	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26 0	$ 287.4
AGT M3	$ 126 8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 1,521.5
TETCO CDS Long Haul	$ 1,000.1	$ 1,000.1	$ 1,000.1	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 1,455.9	$ 16,103.6
Dominion	$ 7.1	$ 7.1	$ 7.1	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 90.7
Dawn via Waddington	$ 25.5	$ 25.5	$ 25.5	$ 25 5	$ 25.5	$ 25.5	$ 25.5	$ 25.5	$ 25.5	$ 25.5	$ 25.5	$ 25 5	$ 306.1
Dawn via PNGTS	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 1,112.1	$ 13,345.1
TGP Long Haul	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 451.6	$ 5,418.6
TGP ConneXion	$ 216 0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 216.0	$ 2,591.7
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,256.4
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 69,524.7**

REDACTED

National Grid Rhode Island
Storage Fixed Costs
Normal Year
($000)

Storage Costs	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Columbia FSS	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 278.4
Dominion GSS	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 436.9
Dominion GSSTE	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 561.5
Exeter LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Providence LNG	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 3,486.2
Tennessee FSMA	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 42.3	$ 507.8
Tetco FSS1	$ 3.5	$ 3.5	$ 3.5	$ 4.7	$ 4.7	$ 4.7	$ 4.7	$ 4.7	$ 4.7	$ 4.7	$ 4.7	$ 4.7	$ 53.0
Tetco SS1	$ 132.1	$ 132.0	$ 132.0	$ 191.2	$ 191.2	$ 191.2	$ 191.2	$ 191.2	$ 191.2	$ 191.2	$ 191.2	$ 191.2	$ 2,116.7
Grand Total	**$ 574.8**	**$ 574.7**	**$ 574.7**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 635.1**	**$ 7,440.5**

REDACTED

National Grid Rhode Island
Supply Fixed Costs
Normal Year
($000)

Supply Costs	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	Grand Total
Everett Supply Deal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 6,822 5
Ramapo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn East Hereford	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion South Point	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millenium East	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dracut Supply Deal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Supply Deal2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,250 0
TGP Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Summer Liquid Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 4.6
Tetco M2 CDS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 CnX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 LH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Summer Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 98.7
AGT Citygate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2,792 3
Winter Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3,668.1
Proposed Summer Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 787.6
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 15,423.7**

REDACTED

National Grid Rhode Island
Hourly Peaking Fixed Costs
Normal Year
($000)

Hourly Peaking Fixed Costs	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
Transportation Fixed Costs	[redacted]												
Portable LNG													
Everett													
Supplier Fixed Costs													
AGT Citygate	[redacted]												
Winter Trucking													
Everett Supply Deal2													
Total Hourly Peaking Fixed Costs	$ 20 9	$ 1,629.5	$ 1,629.5	$ 1,629.5	$ 1,629 5	$ 20 9	$ 20.9	$ 20.9	$ 20.9	$ 20.9	$ 20.9	$ 20.9	$ 6,685.2

REDACTED

National Grid Rhode Island
Storage Inventory
Normal Year
($000; MDth)

Storage Inventory		11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022
LNG	Beg Inv Value	$ 3,390 5	$ 3,334.9	$ 3,247.1	$ 2,712.7	$ 2,314 3	$ 3,174.4	$ 3,282.6	$ 3,316.3	$ 3,354.0	$ 3,492.6	$ 3,401.7	$ 3,475.7
LNG	Beg Inv Volume	753 0	738.8	719.4	601.0	512.7	674 3	698.7	707.3	716.5	747 8	728.3	745.3
LNG	End Inv Value	$ 3,334 9	$ 3,247.1	$ 2,712.7	$ 2,314.3	$ 3,174.4	$ 3,282.6	$ 3,316.3	$ 3,354.0	$ 3,492.6	$ 3,401.7	$ 3,475.7	$ 3,508.3
LNG	End Inv Volume	738 8	719.4	601.0	512.7	674 3	698.7	707.3	716.5	747.8	728 3	745.3	753.0
AGT Storage	Beg Inv Value	$ 7,245.1	$ 6,302.1	$ 4,874.3	$ 3,270.2	$ 1,787 9	$ 1,135.1	$ 1,098.2	$ 2,303.7	$ 2,970.6	$ 4,332 3	$ 5,618.9	$ 6,677.5
AGT Storage	Beg Inv Volume	3,191.7	2,769.4	2,139.5	1,438.7	789.1	506.9	476.3	948.2	1,206.3	1,742.4	2,262.2	2,733.8
AGT Storage	End Inv Value	$ 6,302.1	$ 4,874.3	$ 3,270.2	$ 1,787.9	$ 1,135.1	$ 1,098 2	$ 2,303.7	$ 2,970.6	$ 4,332.3	$ 5,618 9	$ 6,677.5	$ 7,719.0
AGT Storage	End Inv Volume	2,769.4	2,139 5	1,438.7	789.1	506 9	476 3	948.2	1,206.3	1,742.4	2,262 2	2,733.8	3,191.7
TGP Storage	Beg Inv Value	$ 3,333 8	$ 3,270.7	$ 2,429.9	$ 1,592.5	$ 829 2	$ -	$ 99.3	$ 879.0	$ 1,175.7	$ 1,578 8	$ 2,308.4	$ 2,936.5
TGP Storage	Beg Inv Volume	1,353.6	1,328.6	985.3	642.4	333 2	-	32.6	312.0	417.4	561.1	826.8	1,078.8
TGP Storage	End Inv Value	$ 3,270.7	$ 2,429 9	$ 1,592.5	$ 829.2	$ -	$ 99 3	$ 879.0	$ 1,175.7	$ 1,578.8	$ 2,308.4	$ 2,936.5	$ 3,577.8
TGP Storage	End Inv Volume	1,328.6	985.3	642.4	333.2	-	32.6	312.0	417.4	561.1	826 8	1,078.8	1,334.2

REDACTED

The Narragansett Electric Company Gas Cost Recovery Receipt Point Volumes (MDth)	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	8	2	14	14	8	17	-	-	-	-	-	4	68
Dawn via IGTS	-	5	17	16	-	-	-	-	-	-	-	-	39
Dawn via PNGTS	25	211	504	455	245	4	-	-	-	-	-	-	1,444
Dominion SP	16	17	17	15	17	-	17	16	17	-	16	17	166
Dracut Supply	-	-	-	-	-	-	174	107	-	-	76	-	357
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	506
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
Millennium	222	229	229	207	229	57	229	222	229	229	222	229	2,532
Niagara	3	30	33	21	9	32	-	-	-	-	-	-	127
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	431	1,025	1,014	926	938	88	-	-	-	-	-	4	4,425
Tetco M2 SCT	-	9	30	27	4	-	-	-	-	-	-	-	69
Tetco M2 CDS	1,118	1,145	1,179	1,033	1,179	-	-	-	302	333	431	656	7,376
Tetco M3	64	29	88	45	180	1,610	729	419	-	-	6	404	3,574
TGP Z4 Cnx	196	254	296	268	251	147	-	-	83	86	34	142	1,756
TGP Z4 LH	360	420	653	596	378	210	-	-	-	-	-	109	2,726
Transco Leidy	10	19	37	30	27	3	2	2	2	2	2	20	158
Waddington	-	0	0	0	8	-	-	-	-	-	-	-	8
TOTAL PURCHASES TO CITY GATE	2,455	3,482	4,350	3,826	3,476	2,168	1,151	767	633	650	787	1,586	25,332
STORAGE WITHDRAWALS													
Columbia FSS	4	36	73	56	35	1	-	-	-	-	-	-	205
Dominion GSS	25	291	301	247	176	-	-	-	-	-	-	-	1,039
Dominion GSSTE	169	175	175	158	175	85	-	-	-	-	-	-	936
Exeter LNG	6	6	22	23	6	6	6	6	6	6	6	6	106
Providence LNG	13	13	96	65	13	13	13	13	13	13	13	13	292
Tennessee FSMA	-	135	171	174	229	-	-	-	-	-	-	-	709
Tetco SS1	238	322	310	310	-	-	-	-	-	-	-	-	1,180
Tetco FSS1	11	15	14	14	-	-	-	-	-	-	-	-	54
TOTAL WITHDRAWALS TO CITY GATE	466	993	1,162	1,047	635	104	19	19	19	19	19	19	4,522
GRAND TOTAL TO CITY GATE	2,921	4,475	5,512	4,873	4,111	2,272	1,171	786	652	670	806	1,605	29,854

REDACTED

The Narragansett Electric Company Gas Cost Recovery Receipt Point Volumes (MDth)	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	-	-	-	-	-	-	-	-
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	186
Millennium	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara	-	-	-	-	-	-	-	-	-	-	-	-	-
Proposed Liquid	-	-	-	-	-	43	28	28	51	-	36	27	213
TCO Appalachia	-	-	-	-	-	1	51	3	51	51	33	18	208
Tetco M2 SCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 CDS	-	-	-	-	-	55	428	260	493	478	448	448	2,610
Tetco M3	-	-	-	-	-	-	-	-	-	-	-	-	-
TGP Z4 Cnx	-	-	-	-	-	33	281	106	144	211	253	155	1,182
TGP Z4 LH	-	-	-	-	-	-	-	-	-	56	-	102	158
Transco Leidy	-	-	-	-	-	-	-	-	-	-	-	-	-
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES INJECTIONS	5	-	-	-	181	132	788	396	739	796	769	750	4,557
STORAGE WITHDRAWALS													
Columbia FSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSSTE	-	-	-	-	-	-	-	-	-	-	-	-	-
Exeter LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Providence LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee FSMA	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco SS1	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco FSS1	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WITHDRAWALS TO STORAGE INJECTION	-	-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL TO CITY GATE	5	-	-	-	181	132	788	396	739	796	769	750	4,557

REDACTED

The Narragansett Electric Company Gas Cost Recovery Delivery Point Volumes (MDth)	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	8	2	14	13	7	17	-	-	-	-	-	4	65
Dawn via IGTS	-	5	17	16	-	-	-	-	-	-	-	-	37
Dawn via PNGTS	24	208	496	447	241	4	-	-	-	-	-	-	1,418
Dominion SP	16	16	16	15	16	-	16	16	16	-	16	16	160
Dracut Supply	-	-	-	-	-	-	174	107	-	-	76	-	357
Everett Long-Term	-	89	237	175	5	-	-	-	-	-	-	-	505
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Millennium	215	220	220	199	220	55	223	215	222	222	215	222	2,445
Niagara	3	30	32	20	9	32	-	-	-	-	-	-	126
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	421	998	988	902	914	86	-	-	-	-	-	3	4,312
Tetco M2 SCT	-	8	29	26	3	-	-	-	-	-	-	-	67
Tetco M2 CDS	1,087	1,112	1,145	1,003	1,145	-	-	-	293	324	419	638	7,165
Tetco M3	64	28	87	44	178	1,595	722	415	-	-	6	400	3,541
TGP Z4 Cnx	194	251	293	264	248	145	-	-	82	85	34	140	1,735
TGP Z4 LH	356	415	645	589	374	208	-	-	-	-	-	107	2,693
Transco Leidy	10	18	37	30	27	3	2	2	2	2	2	20	156
Waddington	-	0	0	0	8	-	-	-	-	-	-	-	8
TOTAL PURCHASES TO CITY GATE	2,397	3,400	4,255	3,742	3,394	2,144	1,138	755	615	633	766	1,552	24,791
STORAGE WITHDRAWALS													
Columbia FSS	4	35	71	55	34	1	-	-	-	-	-	-	200
Dominion GSS	25	283	293	240	171	-	-	-	-	-	-	-	1,012
Dominion GSSTE	165	170	170	154	170	82	-	-	-	-	-	-	912
Exeter LNG	6	6	22	23	6	6	6	6	6	6	6	6	106
Providence LNG	13	13	96	65	13	13	13	13	13	13	13	13	292
Tennessee FSMA	-	133	169	172	227	-	-	-	-	-	-	-	700
Tetco SS1	231	319	307	307	-	-	-	-	-	-	-	-	1,164
Tetco FSS1	11	14	14	14	-	-	-	-	-	-	-	-	53
TOTAL WITHDRAWALS TO CITY GATE	455	974	1,142	1,029	622	102	19	19	19	19	19	19	4,439
GRAND TOTAL TO CITY GATE	2,852	4,374	5,397	4,771	4,016	2,246	1,157	774	635	652	785	1,571	29,230

REDACTED

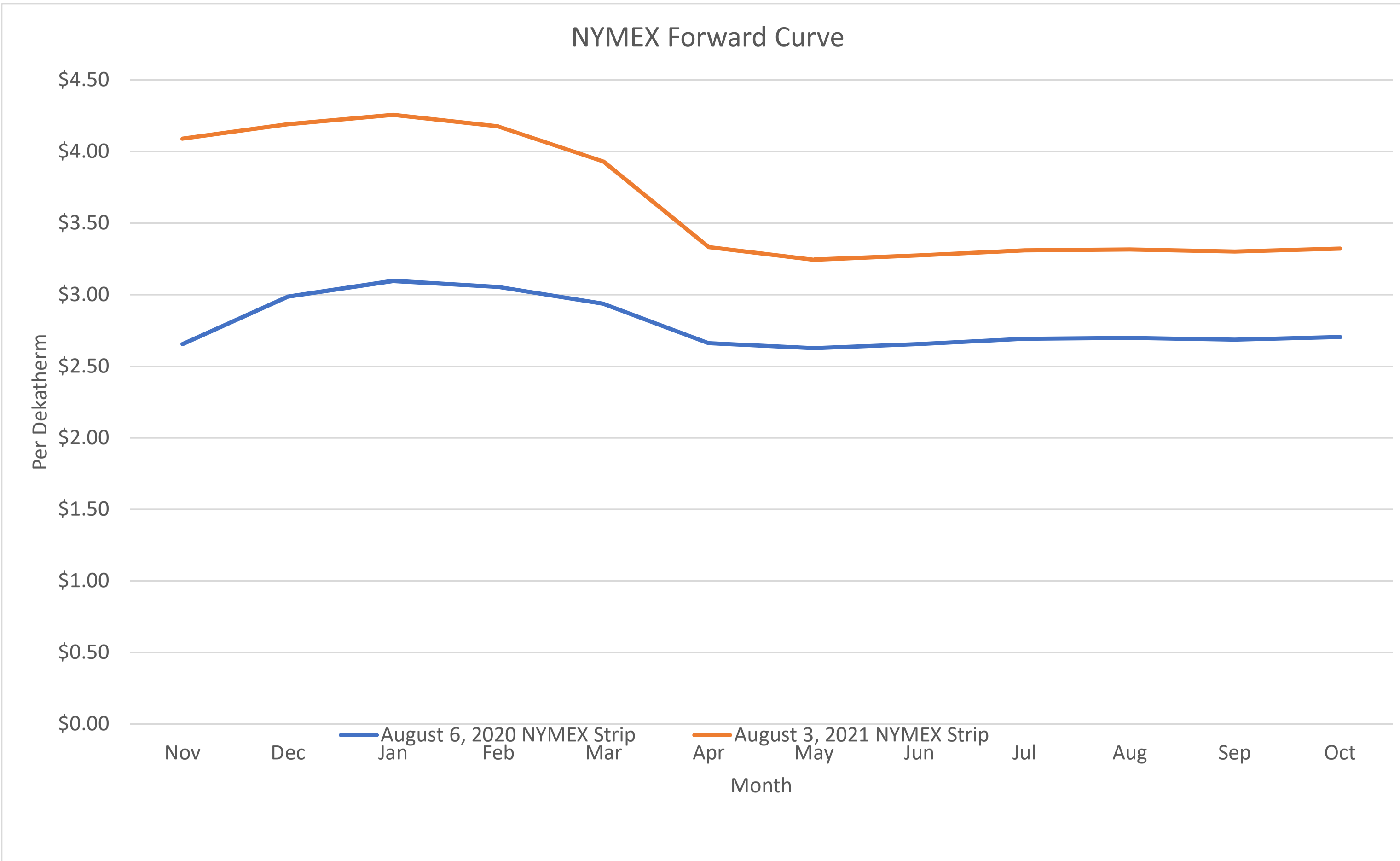
The Narragansett Electric Company Gas Cost Recovery Delivery Point Volumes (MDth)	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	-	-	-	-	-	-	-	-
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	186
Millennium	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara	-	-	-	-	-	-	-	-	-	-	-	-	-
Proposed Liquid	-	-	-	-	-	43	28	28	51	-	36	27	213
TCO Appalachia	-	-	-	-	-	1	51	3	51	51	32	18	205
Tetco M2 SCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 CDS	-	-	-	-	-	54	421	256	485	469	440	440	2,565
Tetco M3	-	-	-	-	-	-	-	-	-	-	-	-	-
TGP Z4 Cnx	-	-	-	-	-	33	279	105	144	210	252	154	1,177
TGP Z4 LH	-	-	-	-	-	-	-	-	-	56	-	101	157
Transco Leidy	-	-	-	-	-	-	-	-	-	-	-	-	-
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES INJECTIONS	5	-	-	-	181	131	779	392	730	786	759	740	4,503
STORAGE WITHDRAWALS													
Columbia FSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSSTE	-	-	-	-	-	-	-	-	-	-	-	-	-
Exeter LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Providence LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee FSMA	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco SS1	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco FSS1	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WITHDRAWALS TO STORAGE INJECTION	-	-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL TO CITY GATE	5	-	-	-	181	131	779	392	730	786	759	740	4,503

Attachment GSP-2

Attachment GSP-2

NYMEX Strip Comparison & Forward Curves

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 6, 2020 NYMEX Strip	$2.654	$2.985	$3.096	$3.053	$2.936	$2.661	$2.625	$2.654	$2.690	$2.697	$2.684	$2.704
August 3, 2021 NYMEX Strip	$4.089	$4.190	$4.256	$4.175	$3.930	$3.331	$3.244	$3.273	$3.308	$3.315	$3.301	$3.320



SUPPLY AREA BASIS SUMMARY

November 2021 - October 2022

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
08/03/2021 NYMEX	$4.089	$4.190	$4.256	$4.175	$3.930	$3.331	$3.244	$3.273	$3.308	$3.315	$3.301	$3.320

SUPPLY AREA	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
TENN Z4	($0.496)	($0.385)	($0.354)	($0.339)	($0.265)	($0.329)	($0.486)	($0.501)	($0.539)	($0.609)	($0.839)	($0.854)
NIAGARA	($0.411)	($0.385)	($0.379)	($0.289)	($0.185)	($0.503)	($0.502)	($0.503)	($0.502)	($0.503)	($0.503)	($0.502)
IROQUOIS RECEIPTS	($0.075)	$0.528	$1.432	$1.417	$0.142	($0.205)	($0.262)	($0.156)	($0.165)	($0.189)	($0.306)	($0.191)
TETCO M3	($0.347)	$0.798	$2.835	$2.655	$0.200	($0.550)	($0.682)	($0.673)	($0.602)	($0.627)	($0.900)	($0.918)
DRACUT	$1.911	$5.971	$10.316	$9.919	$3.341	$0.499	($0.366)	($0.344)	($0.129)	($0.071)	($0.573)	($0.402)
TCO	($0.580)	($0.515)	($0.432)	($0.410)	($0.425)	($0.485)	($0.658)	($0.683)	($0.768)	($0.795)	($0.897)	($0.895)
DAWN	($0.145)	($0.120)	($0.115)	($0.015)	$0.085	($0.140)	($0.175)	($0.190)	($0.202)	($0.227)	($0.223)	($0.240)
TETCO M2	($0.730)	($0.575)	($0.512)	($0.470)	($0.555)	($0.633)	($0.820)	($0.815)	($0.892)	($0.977)	($1.193)	($1.175)
TRANSCO LEIDY	($0.735)	($0.605)	($0.602)	($0.573)	($0.558)	($0.655)	($0.868)	($0.877)	($0.938)	($1.005)	($1.207)	($1.232)
ALGONQUIN	$1.660	$5.728	$10.058	$9.660	$3.110	$0.247	($0.618)	($0.595)	($0.358)	($0.315)	($0.825)	($0.655)
TENN Z6	$1.510	$5.700	$9.612	$9.383	$3.082	$0.290	($0.628)	($0.650)	($0.438)	($0.343)	($0.863)	($0.645)
EASTERN SP	($0.714)	($0.605)	($0.594)	($0.549)	($0.512)	($0.627)	($0.802)	($0.805)	($0.850)	($0.920)	($1.145)	($1.165)
EASTERN NP	($0.944)	($0.840)	($0.830)	($0.785)	($0.744)	($0.717)	($0.895)	($0.897)	($0.942)	($1.011)	($1.235)	($1.255)
IROQUOIS Z1	($0.055)	$0.548	$1.452	$1.437	$0.162	($0.185)	($0.242)	($0.136)	($0.145)	($0.169)	($0.286)	($0.171)
LEIDY HUB	($0.574)	($0.462)	($0.537)	($0.435)	($0.469)	($0.647)	($1.172)	($0.892)	($0.873)	($0.967)	($1.185)	($1.130)
MILLENNIUM EAST POOL	($0.697)	($0.660)	($0.662)	($0.633)	($0.610)	($0.667)	($0.840)	($0.865)	($0.938)	($0.965)	($1.183)	($1.192)
TENN Z6 NORTH	$1.660	$5.728	$10.055	$9.657	$3.110	$0.247	($0.620)	($0.595)	($0.360)	($0.317)	($0.825)	($0.658)

Attachment GSP-3

Rule Curves

Operational Parameters
Non-Daily Metered FT-2 Storage and Peaking Resources

The following Operational Parameters are pursuant to RIPUC NG-GAS No. 101, Section 6, Schedule C:

Effective Period: November 1, 2021 through October 31, 2022

Underground Storage:

Maximum Inventory Level at any time is 100% of MSQ-U
Injections are not allowed.
Minimum Inventory Levels:

November 1	96%
November 15	92%
December 1	88%
December 15	79%
January 1	67%
January 15	58%
February 1	46%
February 15	36%
March 1	26%
March 15	20%
April 1	12%

Peaking Inventory:

Inventory Level allocated on November 1, 2021 = MSQ-P
Injections are not allowed.
Minimum Inventory Levels:

November 1	100%
December 1	92%
January 1	81%
February 1	51%
March 1	33%
April 1	0%

MSQ-U	Maximum Storage Quantity - Underground
MDQ-U	Maximum Daily Quantity - Underground
MSQ-P	Maximum Storage Quantity - Peaking
MDQ-P	Maximum Daily Quantity - Peaking

Attachment GSP-4

Attachment GSP-4

RFPs for PXP

nationalgrid

Request for Proposals ("RFP") for Asset Management Arrangements July 20, 2021

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for Asset Management Arrangements ("AMA") to manage all or a portion of its path originating at Dawn, Ontario for delivery at its city-gate on Tennessee Gas Pipeline ("TGP") in Zone 6 via transportation on Enbridge Gas Inc. ("Enbridge"), TransCanada Pipelines Limited ("TCPL") and Portland Natural Gas Transmission System ("PNGTS") as more fully set forth below. The transportation path is able to deliver a total of 29,000 Dth/day into the point of interconnect between TGP and Buyer's city-gate.

Bidders are advised that due to requirements of its State Approved Retail Access Program ("Program"), National Grid is required to allocate a portion of the Assets to its Program participants each month. Volumes assigned under the Program are made available to National Grid five business days before the 1st of each month and may change on a monthly basis and will be conveyed to Seller in the manner set forth below. Based on historical activity National Grid expects approximately 25% of the ***total*** subject assets to be reserved each month for the Program and will be allocated to a transaction resulting from responses to Package 2. ***Bidders must therefore submit their asset management fee for Package No. 2 only on a volumetric basis*** and must take all necessary actions to allow National Grid to administer the Program. **Bidders may bid on packages for both Packages in increments of 10,000 dth and must indicate the maximum volume and AMA fee for which they are willing to accept an award pursuant to this RFP; in order to administer the Program, National Grid does not anticipate being able to award more than 20,000 dth/day pursuant to Package No. 3. Additionally, for Package 3, Bidders should specify whether their offer is dependent on receiving a specific Delivery Point on the TGP FT-A.** Buyer's allocation of awards pursuant to Package Nos. 2 and 3 shall take into consideration its ability to administer the Program and its ability to maximize value for its firm gas customers.

The successful bidder ("Seller") shall have the right to optimize the assigned assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

I. Provisions

Package No. 2 __ - AMA – PXP - Canadian Only

Term: November 1, 2021 through October 31, 2022.

Assets: Beginning November 1, 2021, National Grid is seeking an AMA using the following Assets:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	29,056	30,656	Dawn	Parkway
TCPL	FT 64273	29,056	30,656	Parkway	East Hereford

Assignment of Assets/ Compliance with Buyer's State Retail Choice Program:

The Assets summarized above represent Buyer's *total* contract path contemplated under this Package No. 2 prior to allocation under the Program or any awards that may be made pursuant to Package No. 3. Assets not assigned under Buyer's Program (or Package No. 3) shall be assigned by Buyer for the entire term at no cost to Seller; notwithstanding the foregoing, Seller shall initially pay the demand charges and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets and for all imputed variable charges related to the volumes delivered by Seller on behalf of Buyer; reimbursement for such charges shall be paid to Seller in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Seller shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Seller and to comply with Buyer's Program. Further, all assignments shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point:

The Delivery Point shall be the point of interconnection between TCPL and PNGTS known as East Hereford, on the U.S. side.

Gas Supply Requirements:

On any day during the period of **November 1, 2021 through April 30, 2022 ("Delivery Period")** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at East Hereford. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TCPL, as well as the volume assigned pursuant to the Program. Subject to satisfaction of these Gas Supply Requirements and the following criteria, Asset Manager shall have the right to optimize the assigned capacity for its own account:

(a) Base-Load Election: At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at East Hereford up to the MDQ made available to Seller during this Delivery Period.

(b) Daily Call: Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ at East Hereford.

Price:

The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to East Hereford.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to East Hereford.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

Daily Call Nominations:

Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Subject to the Gas Supply Requirements, the Program and Buyer's right to elect either Daily Call or Base-Load Gas purchases, Seller shall have the right to optimize the assigned capacity for its own account. Seller shall communicate to Buyer any upstream changes to supply contracts nominated pursuant to this section no later than 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow. Acceptance of changes to upstream supply arrangements communicated by Seller of Buyer after 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow shall be at Buyer's discretion. Consistent with the terms of the Transaction Confirmation and the deliverability of the Assets, Buyer may nominate, and Seller must supply those supplies unaccounted for after the 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow deadline from the Assets assigned to Seller by Buyer.

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA and compliance with Buyer's right to assign volumes under the Program, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA for the full MDQ assignable, as well as on a volumetric basis.**

Import/Export Reporting: Any import/export reporting requirement applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

Package No. 3 __ - AMA – PXP - U.S. and Canadian

Term: November 1, 2021 through October 31, 2022.

Assigned/Released Assets:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	10,000	10,550	Dawn	Parkway
TCPL	FT 64273	10,000	10,550	Parkway	East Hereford
PNGTS	FT 233317	10,000	N/A	Pittsburg	Dracut
TGP	FT-A 349449 FT-A 330580 FT-A 62930	5,000 14,000 4000	N/A	Dracut	Cranston Sales Lincoln Cranston Sales/Pawtucket

Assignment and Release of Assets:

The Assets shall be assigned/released by Buyer for the entire Term at no cost to Asset Manager; notwithstanding the foregoing, Asset Manager shall initially pay the demand charges and Buyer shall reimburse Asset Manager for 100% of the demand charges related to Union and TCPL and for all imputed variable charges related to the volumes delivered by Asset Manager on behalf of Buyer; reimbursement for such charges shall be paid to Asset Manager in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Asset Manager shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. Buyer and Asset Manager each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Asset Manager. All assignments shall be subject to recall in the event that the Asset Manager fails to meet its gas supply obligation to Buyer.

Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. National Grid currently has a negotiated rate with PNGTS which is included herewith. National Grid shall not be responsible for loss of discount resulting from such inaction. National Grid will not advise Bidders or an Asset Manager on potential transactions that may result in a loss of discount.

The parties intend that any transaction entered into pursuant to this RFP shall be structured as an Asset Management Agreement pursuant to FERC Order 712 and any other applicable rules or regulations. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point:

Unless otherwise specified by Buyer, the Delivery Point for Gas purchased hereunder shall be the point of interconnection between Buyer's facilities and TGP in TGP's Zone 6 at Cranston Sales.

Gas Supply Requirements:

On any day during the period of **November 1, 2021 through April 30, 2022** ("Delivery Period") of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point on the U.S. assets of PNGTS and TGP. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Enbridge, TCPL, PNGTS and TGP. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

(a) Base-Load Election: At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point on TGP up to the MDQ made available to Seller during this delivery period.

(b) Daily Call: Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ at TGP Zone 6.

(c) Additional Call: In addition to the Base-Load Election and the Daily Call, on any Day during the delivery period of November 1, 2021 through and including April 30, 2022, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity at the primary delivery point released by Buyer to Seller for each of the PNGTS and TGP Asset(s). Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to these Gas Supply Requirements shall not be cumulative, and the Additional Call may only be exercised after Buyer has exhausted its rights pursuant to the Base-Load Election and Daily Call (i.e., Buyer's right to request gas at any Delivery Point pursuant to this Additional Call provision shall be reduced by quantities already requested). For avoidance of doubt, this Additional Call provision shall only apply to residual capacity remaining on the transportation path as a result of fuel retention applicable to the Assigned Assets.

Price:

The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to Buyer's City-Gate in TGP Zone 6.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to Buyer's City-Gate in TGP Zone 6.

The commodity price for Gas called on through the Additional Call shall be equal to TGP Zone 6 South + $0.10.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assigned/Released Assets may preclude Seller from delivering Gas to the TGP Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the TGP Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

Nominations:

For calls at the Delivery Point at Buyer's City-Gate in TGP Zone 6, Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Upon execution of a binding Transaction Confirmation, or adequate assurance that the Buyer and Seller intend the

Transaction be binding by the first date of the Term, Buyer shall arrange for Seller's use and access of the National Grid Electronic Bulletin Board ("EBB"). Seller shall utilize EBB to schedule the supply to the Delivery Point on TGP, Buyer's city gate, for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA for the full MDQ assignable, as well as on a volumetric basis.**

Import/Export Reporting: Any import/export reporting requirement applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

II. Instructions to Bidders

National Grid will consider Proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Included in this RFP is the form of Transaction Confirmation that National Grid proposes for execution. As part of their Proposal(s), Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation including, but not limited to, language related to FERC, the CFTC and any other applicable regulatory body.

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals must include: **(a) Seller's proposed Reservation Charge for the Package, (b) any specialized language Seller requires in the Transaction Confirmation, and (c) whether**

Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.

III. Schedule (all times are Eastern Standard Time)

July 30, 2021	Proposals must be received by National Grid by **5:00 PM**. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 6, 2021.**

IV. Miscellaneous

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgrid.com/document/83526/download

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment".

This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

Liz Arangio
Director of Gas Supply Planning
Telephone: 617-212-1790

MaryBeth Carroll
Manager of Gas Supply Planning
Telephone: 516-545-3116

Samara Jaffe
Director of Gas Contracting, Compliance & Hedging
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

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Asset Management Arrangement – Package 2
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date:

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposals for Asset Management Arrangements ("AMA") dated July 20, 2021. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall be defined as set forth in Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER/ASSET MANAGER:

BUYER:
The Narragansett Electric Company
100 East Old County Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Fax: (516) 545-5466
Transporters: Enbridge Gas Inc. ("Enbridge"), TransCanada Pipelines Limited ("TransCanada")
Transporters Contract Number:
Trader: Samara Jaffe

Contract Price: **See Special Conditions Section C below.**

Term: Begin: November 1, 2021 **End: October 31, 2022**

Performance Obligation and Contract Quantity: See Special Conditions below.

Delivery Point(s): The Delivery Point shall be the point of interconnection between TransCanada and Portland Natural Gas Transmission System known as East Hereford, on the U.S. side.

Special Conditions:

A. Definitions

"Assets" means the Agreements summarized as follows:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	29,056	30,656	Dawn	Parkway
TransCanada	FT 64273	29,056	30,656	Parkway	East Hereford

"CFTC" shall mean the U.S. Commodities Futures Trading Commission.

"Credit Support Provider" means _______________.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"Demand Charges" means the applicable demand charges due to Union and TransCanada under the assigned Assets.

"FERC" means the Federal Energy Regulatory Commission.

"NEB" means the National Energy Board.

"Program" means Buyer's state approved retail access program.

B. Gas Service and Capacity Assignment

1. **Assignment of Assets:** During the Term, Buyer will assign the Assets to Seller on a Monthly basis after determining Program requirements. Seller shall initially pay the Demand Charges to TransCanada and Enbridge and Buyer shall reimburse Seller for such charges. Buyer shall reimburse Seller for Demand Charges in U.S. dollars using the Bank of Canada's monthly average exchange rate for the Month of business as published on the last Business Day of the Month of production. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Seller and to comply with Buyer's Program. All assignments shall be subject to recall in the event that the Seller fails to meet its Gas supply obligation to Buyer.

   At least five (5) Days prior to the 1st calendar Day of each Month, Buyer shall communicate to Seller, in writing via email, the volume of the Assets that Buyer must assign under the Program and the residual amount that shall be made available to Seller under the transaction for the applicable Month of the Term. Seller agrees to take all necessary actions to allow National Grid to administer the assignments necessary and comply with the Program.

2. **Gas Supply Requirements:**

   i. **November through April:** On any Day during the period of November 1, 2021 through April 30, 2022 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point of the Assets in Seller's control. Subject to satisfaction of these "Gas Supply Requirements" and compliance with National Grid's Program, Asset Manager shall have the right to optimize the assigned capacity for its own account subject to the following:

      a) Base-Load Quantities Option: At least three (3) Business Days prior to the 1st Day of the following Month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply Requirements at the Delivery Point up to the MDQ during the period of November 1, 2021 through April 30, 2022.

      b) Daily-Call Quantities Option: Further, subject to Buyer having exercised its Base-Load Quantities Option pursuant to Special Condition B.2(i)(a), Buyer shall have a right to call on a quantity up to the remaining MDQ for the period of November 1, 2021 through April 30, 2022.

   Subject to these Gas Supply Requirements, Seller shall have the right to optimize the assigned capacity for its own account. Seller shall communicate to Buyer any upstream changes to supplies called on pursuant to this Section no later than 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow. Acceptance of changes to firm Base-Load Quantities communicated by Seller of Buyer after 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow shall be at Buyer's discretion. Consistent with the terms of the Transaction Confirmation and the deliverability of the Assets, Buyer may nominate, and Seller must supply those supplies unaccounted for after the 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow deadline from the Assets assigned to Seller by Buyer.

3. **Nominations:** Buyer shall make all nominations for delivery of Daily Call Quantities prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on Business Day prior to the Holiday).

4. **Termination Option/Recall Rights:** If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder or compliance with allowing Buyer to administer its Program, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets under the terms of the Base Contract.

C. Price

A. Base-Load Quantities: The Contract Price for Gas purchased pursuant to B.2(i)(a) shall be equal to the price posted as the "Index" for Upper Midwest, "Dawn, Ontario," as published in *Platts Inside FERC* for the Month of delivery, plus imputed variable costs (including fuel) to transport Gas from Dawn to the Delivery Point.

B. Daily Call Quantities: The Price for Gas purchased pursuant to B.2(ii)(b) shall be equal to *Platts Gas Daily Daily Price Survey*, Midpoint for Day of flow, Dawn, Ontario, plus imputed variable costs (including fuel) to transport such quantity from Dawn to the Delivery Point.

C. Notwithstanding the foregoing, if in Buyer's sole discretion operational issues on the Assigned Assets may preclude Seller from delivering Gas to the East Hereford Delivery Point at the Base-Load or Daily Call Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the East Hereford Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate this Transaction Confirmation.

D. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the assigned capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $______ per MMBtu of capacity made available by Buyer to Seller calculated on the TransCanada East Hereford Delivery Point for the Month of flow. This payment shall be reflected as a credit to Buyer in Seller's Invoice for the applicable Month.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement' for Seller means the Exposure (as defined below), minus the sum of (i) the amount of cash previously transferred by Seller to Buyer, (ii) the amount of cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of Buyer, and (iii) the undrawn value of each such Letter of Credit; provided, however, that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller has a Credit Rating of at least BBB- from S&P and/or Baa3 from Moody's, and (ii) no Event of Default with respect to Seller has occurred and is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit. The Collateral Requirement for Buyer means zero (0).

"Exposure" shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

G. Import/Export Reporting

Any import/export reporting requirements applicable to the quantities of Gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service, or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

G. Changes in Law

If the NEB, FERC, CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, either party shall provide Notice of such event to the other party and the parties shall negotiate in good faith an amendment to this Transaction Confirmation or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller: By: ___________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By:_______________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

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Asset Management Arrangement – Package 3
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date:

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposals for Asset Management Arrangements ("AMA") dated July 20, 2021. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall be defined as set forth in the Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER/ASSET MANAGER:

BUYER:
The Narragansett Electric Company
100 East Old County Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Fax: (516) 545-5466
Transporters: Enbridge Gas Inc. ("Enbridge"), TransCanada Pipelines Limited ("TransCanada"); Portland Natural Gas Transmission System ("PNGTS"); Tennessee Gas Pipeline ("TGP")

Transporters Contract Number:
Trader: Samara Jaffe

Contract Price: **See Special Conditions Section C below.**

Term: Begin: November 1, 2021 **End: October 31, 2022**

Performance Obligation and Contract Quantity: See Special Conditions below.

Delivery Point(s): Unless otherwise specified by Buyer, the Delivery Point for Gas purchased hereunder shall be the point of interconnection between Buyer's Rhode Island facilities and TGP in TGP's Zone 6.

Special Conditions:

A. Definitions

"Assets" means the Agreements summarized as follows:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	10,000	10,550	Dawn	Parkway
TCPL	FT 64273	10,000	10,550	Parkway	East Hereford
PNGTS	FT 233317	10,000	N/A	Pittsburg	Dracut
TGP	FT-A 349449 FT-A 330580 FT-A 62930	5,000 14,000 4,000	N/A N/A N/A	Dracut	Cranston Sales Lincoln Cranston Sales/Pawtucket

"CFTC" shall mean the U.S. Commodities Futures Trading Commission.

"Credit Support Provider" means _______________.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"Demand Charges" means the applicable demand charges due to Union and TransCanada under the assigned Assets.

"EBB" shall mean Buyer's Electronic Bulletin Board used for confirmation of supplies to its city-gate/Delivery Point.

"FERC" means the Federal Energy Regulatory Commission.

"NEB" means the National Energy Board.

B. Gas Service and Capacity Assignment

1. Assignment of Assets: The Assets shall be assigned/released by Buyer for the entire Term at no cost to Asset Manager; notwithstanding the foregoing, Asset Manager shall initially pay the demand charges and Buyer shall reimburse Asset Manager for 100% of the demand charges related to Enbridge and TCPL and for all imputed variable charges related to the volumes delivered by Asset Manager on behalf of Buyer; reimbursement for such charges shall be paid to Asset Manager in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Asset Manager shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries and all losses of discount associated or applicable rate to the Asset. Buyer and Asset Manager each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Asset Manager. All assignments shall be subject to recall in the event that the Asset Manager fails to meet its gas supply obligation to Buyer.

2. Gas Supply Requirements:

a. November through April: On any Day during the period of November 1, 2021 through April 30, 2022 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the TGP Zone 6 Delivery Point. Subject to satisfaction of these "Gas Supply Requirements", Asset Manager shall have the right to optimize the assigned capacity for its own account subject to the following:

i. Base-Load Quantities Option: At least three (3) Business Days prior to the 1st Day of the following Month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply Requirements at the TGO Zone 6Delivery Point up to the MDQ during the period of November 1, 2021 through April 30, 2022.

ii. Daily-Call Quantities Option: Further, subject to Buyer having exercised its Base-Load Quantities Option pursuant to Special Condition B.2(i)(a), Buyer shall have a right to call on a quantity up to the remaining MDQ for the period of November 1, 2021 through April 30, 2022.

iii. Additional Call: In addition to the Base-Load Election and the Daily Call, on any Day during the delivery period of November 1, 2021 through and including April 30, 2022, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity at the primary delivery point released by Buyer to Seller for each of the PNGTS and TGP Asset(s). Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to these Gas Supply Requirements shall not be cumulative, and the Additional Call may only be exercised after Buyer has exhausted its rights pursuant to the Base-Load Election and Daily Call (*i.e.*, Buyer's right to request gas at any Delivery Point pursuant to this Additional Call provision shall be reduced by quantities already requested).

3. Nominations: Buyer shall make all nominations for delivery of Daily Call Quantities and the Additional Call prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on Business Day prior to the Holiday). Buyer shall nominate all Gas purchased hereunder into the EBB for confirmation.

4. Termination Option/Recall Rights: If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder or compliance with allowing Buyer to administer its Program, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets under the terms of the Base Contract.

C. Price

a. Base-Load Quantities: The Contract Price for Gas purchased pursuant to B.2(a)(i) shall be equal to the price posted as the "Index" for Upper Midwest, "Dawn, Ontario," as published in *Platts Inside FERC* for the Month of delivery, plus imputed variable costs (including fuel) to transport Gas from Dawn to the Delivery Point.

b. Daily Call Quantities: The Price for Gas purchased pursuant to B.2(b)(ii) shall be equal to *Platts Gas Daily Daily Price Survey*, Midpoint for Day of flow, Dawn, Ontario, plus imputed variable costs (including fuel) to transport such quantity from Dawn to the Delivery Point.

c. Additional Call Quantities: The Price for Gas purchased pursuant to B.2(b)(iii) shall be equal to *Platts Gas Daily Daily Price Survey*, Midpoint for Day of flow, TGP Zone 6 South + $0.10.

d. Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the TGP Delivery Point pursuant to this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the TGP Zone 6 Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate this Transaction Confirmation.

D. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the assigned capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $________ payable in monthly installments of $ ________.. This payment shall be reflected as a credit to Buyer in Seller's Invoice for the applicable Month.

E. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement' for Seller means the Exposure (as defined below), minus the sum of (i) the amount of cash previously transferred by Seller to Buyer, (ii) the amount of cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of Buyer, and (iii) the undrawn value of each such Letter of Credit; provided, however, that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller has a Credit Rating of at least BBB- from S&P and/or Baa3 from Moody's, and (ii) no Event of Default with respect to Seller has occurred and is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit. The Collateral Requirement for Buyer means zero (0).

"Exposure" shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

F. Asset Management Arrangement ("AMA")

The Parties agree that the transactions hereunder constitute an AMA as defined by FERC in Order No. 712 (as modified and clarified and in accordance with FERC's rules and regulations, and that Seller is acting as Asset Manager as defined in 18 CFR 284.8(h)(3). If it is determined that this transaction does not constitute an AMA, the parties agree to modify the transaction as required while maintaining, to the extent possible, the economics of the transaction.

G. Import/Export Reporting

Any import/export reporting requirements applicable to the quantities of Gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service, or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

H. Changes in Law

If the NEB, FERC, CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, either party shall provide Notice of such event to the other party and the parties shall negotiate in good faith an amendment to this Transaction Confirmation or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller: By: ____________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By:_______________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-5

Attachment GSP-5

RFP for AMA Dawn Waddington to Zone 6 Lincoln

nationalgrid

Request for Proposals ("RFP") for Asset Management Arrangement July 20, 2021

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for an Asset Management Arrangement ("AMA") as more fully set forth below. The successful bidder ("Seller" or "Asset Manager") shall have the right to optimize the assigned assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements set forth below.

Package No. 1 – AMA (Dawn- TGP Zone 6)

I. Provisions:

Term: November 1, 2021 through October 31, 2022.

Delivery Period: November 1, 2021 through and including March 31, 2022.

Release/Assignment of Assets: The Assets to be assigned and released are set forth below. The Assets shall be assigned/released by Buyer for the entire Term at no cost to Seller. Buyer shall remain responsible for payment of all demand charges related to the Assets (except any potential loss of discount related to activities of Seller). Notwithstanding the forgoing, Seller shall initially pay the Enbridge and TransCanada demand charges and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets; reimbursement for such charges shall be paid to Seller in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Seller. All assignments shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Assigned Assets: During the Term, Buyer shall assign firm transportation capacity on the following pipelines:

Enbridge Gas Inc. ("Enbridge")
TransCanada Pipelines Limited ("TransCanada")
Iroquois Gas Transmission System, L.P. ("Iroquois")
Tennessee Gas Pipeline Company, L.L.C. ("Tennessee")

Please see table below for contract details.

Pipeline	Contract	Quantity Dt/day	Quantity Gj/day	Receipt Point	Delivery Point
Enbridge	M12164	1,025	1,081	Dawn	Parkway
TransCanada	42386	1,012	1,068	Parkway	Waddington
Iroquois	50001	1,012	NA	Waddington	Wright
Tennessee	95345	1,000	NA	Wright	Lincoln, RI

Delivery Point: The Delivery Point shall be the primary Delivery Point(s) of the FERC regulated Assets.

Gas Supply Requirements: On any day during the period of **November 1, 2021 through March 31, 2022 ("Delivery Period")** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the *Tennessee Delivery Point.* The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Enbridge, TransCanada, Iroquois and Tennessee. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

(a) At least five business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this Delivery Period.

(b) Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

Additional Call – In addition to the Gas Supply Requirements above, on any Day during the period of November 1, 2021 through March 31, 2022 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity of each of the Iroquois and Tennessee Assets at the primary Delivery Point(s) under each such released Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm Base-Load and daily call supplies (*i.e.*, Buyer's right to request gas at the Iroquois or Tennessee Delivery Point pursuant to these Gas Supply Requirements provisions and under this Additional Call provision shall be reduced by quantities requested at any upstream Delivery Point). For avoidance of doubt, this Additional Call provision shall only apply to residual capacity remaining on the transportation path as a result of fuel retention applicable to the Assigned Assets.

Nominations:

Buyer shall make all nominations for delivery of Gas hereunder prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on Business Day prior to the Holiday).

Upon execution of a binding Transaction Confirmation, or adequate assurance that the Buyer and Seller intend the Transaction be binding by the first date of the Term, Buyer shall arrange for Seller's use and access of the National Grid Electronic Bulletin Board ("EBB"). Seller shall utilize EBB to schedule the supply to the Delivery Point on Tennessee, Buyer's city gate, for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

Price:

The commodity price for Gas called on through the exercise of a Daily Call shall be equal to *Platts Gas Daily Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Tennessee Delivery Point.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Tennessee Delivery Point.

The commodity price for Gas called on through Additional Call shall be the greater of the Daily Call Price or the *Platts Gas Daily Daily Price Survey* price for Tennessee Zone 6 South Pool plus $0.10 per dt.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load, Daily Call or Additional Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Daily Call Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Tennessee Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

Asset Management Fee:

Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal, Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the Term.**

Form of Agreement:

Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Contract or ISDA Gas Annex. Included with this RFP is the form of Transaction Confirmation that National Grid proposes for execution. **As part of their Proposal, Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation.**

Import/Export Reporting:

Any import/export reporting requirements applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

Submission of Proposals:

Proposals must be submitted by the date specified in the Schedule below. Proposals must include: **(a) Seller's proposed Asset Management Payment or Price for the AMA Package, (b) any proposed exceptions to the Transaction Confirmation and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

II. Instructions to Bidders:

Proposals must be submitted by the date specified in the Schedule below via email to the following email address:

GasRFP@nationalgrid.com.

Any questions in connection with this RFP should be sent via email to the email address provided above.

III. Schedule (all times are Eastern Standard Time):

June 30, 2021	Proposals must be received by National Grid by 5:00PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 6, 2021.**

V. Form of Agreement:

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Contract or ISDA Gas Annex. Please be advised that if the Winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the CSA.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered by National Grid, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. Potential Sellers shall be subject to satisfactory credit review by National Grid.

VI. Compliance with National Grid's Supplier Code of Conduct:

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgrid.com/document/83526/download

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

Liz Arangio
Director of Gas Supply Planning
Telephone: 617-212-1790

MaryBeth Carroll
Manager of Gas Supply Planning
Telephone: 516-545-3116

Samara Jaffe
Director of Gas Contracting, Compliance & Hedging
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

nationalgrid

Transaction Confirmation – Package 1
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date: ____________

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposals for Asset Management Arrangements dated July 20, 2021. This Transaction Confirmation is subject to the Base Contract between Seller and Buyer, dated ________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:

Attn:
Phone:
Fax:
Transporters:
Transporters Contract Number:
Trader:

BUYER:
The Narragansett Electric Company
100 East Old County Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Fax: (516) 545-5466
Transporters: Enbridge Gas Inc. ("Enbridge"), TransCanada Pipelines Limited ("TransCanada"), Iroquois Gas Transmission System, L.P. ("Iroquois")
Tennessee Gas Pipeline Company, L.L.C. ("Tennessee").
Transporters Contract Number:
Trader: Samara Jaffe

Contract Price: **See Special Conditions Section C below.**

Term: Begin: November 1, 2021 **End: October 31, 2022**

Performance Obligation and Contract Quantity: See Special Conditions below.

Delivery Point(s): Subject to Buyer's right to exercise the Additional Call, the primary Delivery Point shall be the point of interconnection between Tennessee and Buyer's distribution system that is the primary Delivery Point under the Tennessee Asset.

Special Conditions:

A. Definitions

"Assets" means the Agreements summarized as follows:

Pipeline	Contract	Quantity Dt/day	Quantity Gj/day	Receipt Point	Delivery Point
Enbridge	M12164	1,025	1,081	Dawn	Parkway
TransCanada	42386	1,012	1,068	Parkway	Waddington
Iroquois	50001	1,012	NA	Waddington	Wright
Tennessee	95345	1,000	NA	Wright	Lincoln, RI

"CFTC" shall mean the Commodities Futures Trading Commission.

"Credit Support Provider" means________________________.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"EBB" means Buyer's Electronic Bulletin Board utilized for confirmation of Gas. "FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A" by S&P and "A2" by Moody's in a form reasonable acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Services, Inc., or its successor.

"S&P" means S&P Global Ratings, or its successor.

B. Gas Service and Capacity Assignment

1. **Release and Assignment of Assets:** During the Term, Buyer will release/assign, on a pre-arranged, non-biddable basis, at no cost to Seller, the Assets. Buyer shall be responsible for the payment of all demand charges related to the Assets. Notwithstanding the foregoing, Seller shall initially pay the demand charges to TransCanada and Enbridge and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets for the volumes delivered by Seller to Buyer under this Transaction Confirmation. Reimbursement of such charges shall be paid in U.S. dollars and based on the Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Seller shall be responsible for all variable costs in connection with the Assets during the Term unrelated to deliveries for Buyer. Buyer and Seller each agree to take such actions and execute all documents as may be required to effectuate the assignment of the Assets from Buyer to Seller. All assignments shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

2. **Gas Supply Requirements:**

A. On any day during the period of November 1, 2021 through March 31, 2022 ("Delivery Period") of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Tennessee Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Enbridge, TransCanada, Iroquois and Tennessee. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

i. At least five business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this Delivery Period.

ii. Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

iii. Additional Call – In addition to the Gas Supply Requirements set forth in Special Condition B(2)(A) of this Transaction Confirmation, on any Day during the period of November 1, 2021 through March 31, 2022 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity of each of the Iroquois and Tennessee Assets at the primary Delivery Point(s) under each such released Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm base-load and daily call supplies (i.e., Buyer's right to request gas at the Iroquois or Tennessee Delivery Point(s) pursuant to these Gas Supply Requirements provisions and under this Additional Call provision shall be reduced by quantities requested at any upstream Delivery Point).

B. Termination Right: If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Nominations

Buyer shall make all nominations for all delivery of Gas hereunder prior to 10:00 a.m. prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (i.e., nominated ratably on Business Day prior to the Holiday).

Buyer shall arrange for Seller's use and access of the EBB. Seller shall utilize the EBB to schedule all Gas purchased pursuant to this AMA to the Delivery Point(s) for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

D. Price The commodity price for Gas purchased pursuant to Special Condition 2 shall be as follows:

1. The commodity price for Gas called on through the exercise of a Daily Call pursuant to Special Condition B(2)(A)(ii) shall be equal to *Platts Gas Daily Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

2. The commodity price for Gas called on through the Base-Load option pursuant to Special Condition B(2)(A)(i) shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

3. The commodity price for Gas called on through the Additional Call option pursuant to Special Condition B(2)(B) shall be equal to the greater of the Daily Call Price or the *Platts Gas Daily Daily Price Survey* price for Tennessee Zone 6 South Pool plus $0.10 per dt.

4. Notwithstanding the foregoing, if in Buyer's sole discretion operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load, Daily Call or Additional Call Price stated in this Section D, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Tennessee Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure to deliver shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate this Transaction Confirmation.
5.

E. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the assigned capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $___________, payable in equal monthly installments of $______.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB by S&P and/or Baa2 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement' for Seller means the Exposure (as defined below), minus the sum of (i) the amount of cash previously transferred by Seller to Buyer, (ii) the amount of cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of Buyer, and (iii) the undrawn value of each such Letter of Credit; provided, however, that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller has a Credit Rating of at least BBB from S&P and/or Baa2 from Moody's, and (ii) no Event of Default with respect to Seller has occurred and is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB by S&P and/or Baa2 by Moody's, (b) cash, or (c) a Letter of Credit. The "collateral Requirement" for Buyer means zero (0).

"Exposure" shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

G. Import/Export Reporting

Any import/export reporting requirements applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service, or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

H. Changes in Law

If the FERC, CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Transaction Confirmation or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller: By: ____________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By:__________________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-6

Attachment GSP-6

RFP for AMA Dracut to Citygate

nationalgrid

Request for Proposals (“RFP”) for The Narragansett Electric Company d/b/a National Grid Asset Management Arrangement (“AMA”) and Gas Supply July 20, 2021

The Narragansett Electric Company d/b/a National Grid (“Narragansett” or “Buyer”) is seeking proposals (“Proposals”) for an AMA as more fully set forth below. The successful bidder(s) (“Seller”) shall have the right to optimize the assets (“Assets”) subject to satisfying Buyer’s Gas Supply Requirements. **Bidders may bid in increments of 7,500 dth/day and should indicate the maximum volume they would be willing to receive under an AMA.** The maximum delivered quantity of the Assets to be released by Buyer pursuant to an AMA resulting from this RFP is **15,000 dt/day** (“MDQ”).

Package No. 6 – AMA (Dracut to City Gate)

I. Provisions

Term: November 1, 2021 through October 31, 2022.

Assets: During the Term, Buyer shall release FT-A capacity Contract No. 349449 with Tennessee Gas Pipeline Company L.L.C. (“TGP”), having primary receipts at Dracut, MA (pin number 412538) and primary deliveries in Zone 6 at the point(s) of interconnection between TGP and Buyer’s facilities in Cranston, RI, (pin number 420750).

The Assets shall be released by Buyer for the entire Term at no cost to Seller. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point: The point of interconnection between TGP and Buyer’s facilities at Cranston, RI.

Gas Supply Requirements: On any day during the period of **November 1, 2021 through March 31, 2022**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account.

Price:

For the first 50 days which Buyer exercises the call option pursuant to Gas Supply Requirements, the Price shall be equal to the price for Tennessee, Zone 6, Delivered North - as published in *Platts Gas Daily Daily Price Survey* for the day of flow, plus the variables to transport Gas to the Delivery Point. After 50 days of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to TGP, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* $0.10, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

Daily Call Nominations:

Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Upon execution of a binding Transaction Confirmation, or adequate assurance that the Buyer and Seller intend the transaction be binding by the first date of the Term, Buyer shall arrange for Seller's use and access of the National Grid Electronic Bulletin Board ("EBB"). Seller shall utilize EBB to schedule the supply to the Delivery Point on Tennessee, Buyer's city gate, for confirmation by National Grid's Gas Control. Use of the EBB for other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

Asset Management Fee:

Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal, Bidders must specify the Asset Management Fee to be paid to Buyer.**

II. Instructions to Bidders

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com.

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals should include: **(a) Seller's proposed Asset Management Fee and/or Reservation Fee (b) any proposed exceptions to the Transaction Confirmation attached hereto for Package No. 5 (c) whether Bidder requires takes be ratable and (d) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

III. Schedule (all times are Eastern Time)

July 30, 2021	Proposals must be received by National Grid by **5:00 PM EST**. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 6, 2021.**

IV. Form of Agreement

National Grid will consider proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgrid.com/document/83526/download

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

Liz Arangio
Director of Gas Supply Planning
Telephone: 617-212-1790

MaryBeth Carroll
Manager of Gas Supply Planning
Telephone: 516-545-3116

Samara Jaffe
Director of Gas Contracting, Compliance & Hedging
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

nationalgrid

Asset Management Arrangement – Package 6
Transaction Confirmation
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

		Date: ____________ Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposal for Asset Management Arrangements dated July 20, 2021. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:	BUYER:
_______ Attn:____ Phone:__ Fax:____ Base Contract No. _______ Transporters: ____ Transporters Contract Number: ____ Trader: _	The Narragansett Electric Company 100 East Old County Road Hicksville, New York 11801 Attn: Contract Administration Phone: (516) 545-6068 Fax: (516) 545-5466 Base Contract No. Transporters: Tennessee Gas Pipeline Company, L.L.C. ("Tennessee") Trader: Samara Jaffe

Contract Price: See Special Conditions Section C Below

Term: Begin: November 1, 2021 End: October 31, 2022

Performance Obligation and Contract Quantity: See Special Conditions Below

Delivery Point(s): The primary points of interconnection between Tennessee and Buyer's facilities in Tennessee Zone 6 released by Buyer to Seller as part of the Assets

Special Conditions:

A. Definitions

"Assets" means Buyer's FT-A Contracts with Tennessee having primary receipts at Dracut, MA (pin number 412538) and primary deliveries in Zone 6 the point(s) of interconnection between Tennessee and Buyer's facilities in Cranston, RI. The maximum delivered quantity of the Assets is **15,000 dt/day** ("MDQ").

"Credit Support Provider" means__________________________.

"CFTC" means the Commodity Futures Trading Commission.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"EBB" means Buyer's Electronic Bulletin Board utilized for confirmation of Gas.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Service, Inc. or its successor.

"S&P" means S&P Global Ratings, or its successor.

B. Gas Service and Capacity Release

a. **Release of Assets:** During the Term, Buyer shall release the Assets on a pre-arranged, non-biddable basis, at no cost to Seller. Buyer shall be responsible for the payment of all demand charges related to the Assets. Seller shall be responsible for all variable costs in connection with the Assets during the Term unrelated to deliveries for Buyer. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

b. **Daily Call:** On any day during the period of **November 1, 2021 through March 31, 2022**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point(s).

c. **Termination Option:** If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Price: For the 50 days which Buyer exercises the call option pursuant to Gas Supply Requirements, the Price shall be equal to the price for Tennessee, Zone 6, Delivered North - as published in *Platts Gas Daily Daily Price Survey* for the day of flow, plus the variables to transport Gas to the Delivery Point. After Buyer has exercised 50 days of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to Tennessee, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* $0.10, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

Notwithstanding the foregoing, if in *Buyer's sole discretion* operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate this Transaction Confirmation.

D. Nominations

Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Buyer shall arrange for Seller's use and access of the EBB. Seller shall utilize the EBB to schedule all Gas purchased pursuant to this AMA to the Delivery Point(s) for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

E. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the released capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $_______, payable in equal monthly installments of $_________. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to National Grid, (ii) the amount of Cash held by National Grid as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of National Grid ("Letter of Credit"), and (iii) the undrawn value of each Letter of Credit ; provided, however, that the Collateral Requirement of Seller will be deemed to be zero

(0) if on the relevant Valuation Date, (i) no Event of Default with respect to Seller or its Credit Support Provider has occurred and is continuing, and (ii) the guaranty provided by Seller is in full force and effect. The "Collateral Requirement" for National Grid means zero (0).

Exposure. shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

G. Asset Management Arrangement

The Parties agree that the transactions hereunder constitute an Asset Management Arrangement, as defined by FERC in Order No. 712 (as modified and clarified) and in accordance with FERC's rules and regulations, and that Seller is acting as Asset Manager as defined in 18 CFR 284.8(h)(3).

H. Changes in Law

If the FERC, CFTC or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller: By: ______________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By:______________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-7

Attachment GSP-7

RFP for AMA Columbia Gas Transmission ("TCo")

Request for Proposals ("RFP") for
The Narragansett Electric Company d/b/a National Grid
Asset Management Arrangement ("AMA")
July 20, 2021

The Narragansett Electric Company d/b/a National Grid ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an AMA as more fully set forth below. The successful bidder(s) ("Seller") shall have the right to optimize the assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

Package No. 4 - AMA (TCo – Broadrun to Hanover)

I. Provisions

Term: November 1, 2021 through October 31, 2022.

Assets: During the Term, Buyer shall release FTS contract 31523 with Columbia Gas Transmission L.L.C. ("TCo"), having primary receipts at Broadrun and primary deliveries in at the interconnection between TCo and Algonquin Gas Transmission, LLC ("AGT") at TCo-Hanover and a maximum daily quantity of 10,000 dth/day ("MDQ").

The Assets shall be released by Buyer for the entire Term at no cost to Seller. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point: The point of interconnection between TCo and AGT into AGT known as TCo-Hanover.

Gas Supply Requirements: On any day during the period of **November 1, 2021 through April 15, 2022** ("Delivery Period"), Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account subject to the following.

(a) At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this Delivery Period.

(b) Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have the right to call on a quantity up to the remaining MDQ.

Price: The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for TCo Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

The commodity price for Gas Called on through the Base-Load option shall be equal to *Platts Inside FERC* for TCo Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

Daily Call Nominations: Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal, Bidders must specify the Asset Management Fee to be paid to Buyer.**

II. Instructions to Bidders

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com.

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals should include: **(a) Seller's proposed Asset Management Fee and/or Reservation Fee (b) any proposed exceptions to the Transaction Confirmation attached hereto and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

III. Schedule (all times are Eastern Time)

July 30, 2021	Proposals must be received by National Grid by 5:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 6, 2021.**

IV. Form of Agreement

National Grid will consider proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgrid.com/document/83526/download

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

Liz Arangio
Director of Gas Supply Planning
Telephone: 617-212-1790

MaryBeth Carroll
Manager of Gas Supply Planning
Telephone: 516-545-3116

Samara Jaffe
Director of Gas Contracting, Compliance & Hedging
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

nationalgrid

Asset Management Arrangement – Package 4
Transaction Confirmation
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposal for Asset Management Arrangements dated July 20, 2021. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:	BUYER:
_______	The Narragansett Electric Company
Attn:____	100 East Old County Road
Phone:__	Hicksville, New York 11801
Fax:____	Attn: Contract Administration
Base Contract No. _______	Phone: (516) 545-6068
Transporters: ____	Fax: (516) 545-5466
Transporters Contract Number: ____	Base Contract No.
Trader:	Transporters: Columbia Gas Transmission L.L.C. ("TCo")
	Trader: Samara Jaffe

Contract Price: See Special Conditions Section C Below

Term: Begin: November 1, 2021 End: October 31, 2022

Performance Obligation and Contract Quantity: See Special Conditions Below

Delivery Point(s): The point of interconnection between TCo and Algonquin Gas Transmission LLC ("AGT") into AGT known as TCo-Hanover.

Special Conditions:

A. Definitions

"Assets" means Buyer's FTS contract 31523 with TCo, having primary receipts at Broadrun and primary deliveries in at the interconnection between TCo and AGT at TCo-Hanover and a maximum daily quantity of 10,000 dth/day ("MDQ").

"Credit Support Provider" means__________________________.

"CFTC" means the Commodity Futures Trading Commission.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Service, Inc. or its successor.

"S&P" means S&P Global Ratings, or its successor.

B. Gas Service and Capacity Release

a. **Release of Assets:** During the Term, Buyer shall release the Assets on a pre-arranged, non-biddable basis, at no cost to Seller. Buyer shall be responsible for the payment of all demand charges related to the Assets. Seller shall be responsible for all variable costs in connection with the Assets during the Term unrelated to deliveries for Buyer. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

b. **Gas Supply Requirements:** On any day during the period of **November 1, 2021 through April 15, 2022** ("Delivery Period"), Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point subject to the following

(i) At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this Delivery Period.

(ii) Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

c. **Termination Option:** If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Price:

The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily Daily Price Survey* ($MMBtu) Midpoint for TCo Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

The commodity price for Gas called on through the exercise of a Base-Load option shall be equal to *Platts Inside FERC* for TCo Pool.

Notwithstanding the foregoing, if in *Buyer's sole discretion* operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate this Transaction Confirmation.

D. Nominations

Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

E. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the released capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $_______, payable in equal monthly installments of $_________. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- by S&P and/or Baa3 by Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to Buyer, (ii) the amount of Cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Buyer for the benefit of Buyer, and (iii) the undrawn value of each Letter of Credit;

provided, however, that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller has a Credit Rating of at least BBB- by S&P and/or Baa3 by Moody's, and (ii) no Event of Default with respect to Seller has occurred and is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit. The "Collateral Requirement" for Buyer means zero (0).

Exposure. shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

G. Asset Management Arrangement

The Parties agree that the transactions hereunder constitute an Asset Management Arrangement, as defined by FERC in Order No. 712 (as modified and clarified) and in accordance with FERC's rules and regulations, and that Seller is acting as Asset Manager as defined in 18 CFR 284.8(h)(3).

H. Changes in Law

If the FERC, CFTC or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller: By: ______________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By:______________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-8

Attachment GSP-8

RFP for AMA Millennium Pipeline to Ramapo

nationalgrid

**Request for Proposals ("RFP") for
Asset Management Arrangement
July 20, 2021**

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for an Asset Management Arrangement ("AMA") as more fully set forth below. The successful bidder ("Seller") shall have the right to optimize the released assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

Package No. 5 – AMA – Millennium Eastern System Upgrade – Corning-to Ramapo AGT

I. Provisions:

Term: November 1, 2021 through October 31, 2022.

Assets and the Release of Assets:

During the Term, Buyer shall release at no cost to Seller, 5,000 dth/day (the "MDQ") of its Firm Transportation Contract No. 210165 with Millennium Pipeline Company, L.L.C. ("Millennium") having a primary point of receipt of Corning-Empire PL and primary firm delivery entitlements to Ramapo-AGT.

Buyer shall remain responsible for payment of all demand charges related to the Assets (except any potential loss of discount related to activities of Seller). A copy of Buyer's Contract No. 210165 and the negotiated rate agreement with Millennium are included with this RFP. National Grid will not advise Bidders or an Asset Manager on potential transactions that may result in a loss of discount.

Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. The parties intend that any transaction entered into pursuant to this RFP shall be structured as an AMA pursuant to FERC Order 712 and any other applicable rules or regulations. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point (s): The Delivery Point shall be the point of interconnect between Millennium and Algonquin Gas Transmission Pipeline ("AGT") at Ramapo-AGT, into Buyer's AGT capacity.

Gas Supply Requirements: On any day during the period of **November 1, 2021 through April 30, 2022** ("Delivery Period") of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

(a) At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this Delivery Period.

(b) Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

Price: The commodity price for Gas called on through the exercise of a daily call shall be based on *Platts Gas Daily* – Daily Price Survey ($MMBtu) Midpoint for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

The commodity price for Gas called on through the Base-Load option shall be based on *Platts Inside FERC* for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

Daily Call Nominations: For Daily Calls at the Delivery Point(s), Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with each AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA.**

Form of Agreement: National Grid will consider Proposals only from Bidders who have an executed NAESB Base

Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Included in this RFP is the form of Transaction Confirmation that National Grid proposes for execution. As part of their Proposal(s), Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation including, but not limited to, language related to FERC, the CFTC and any other applicable regulatory body.

II. Instructions to Bidders

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals must include: **(a) Seller's proposed Reservation Charge for the Package, (b) any specialized language Seller requires in the Transaction Confirmation, and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

III. Schedule (all times are Eastern Standard Time)

July 30, 2021	Proposals must be received by National Grid by **5:00 PM**. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 6, 2021.**

IV. Form of Agreement

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgrid.com/document/83526/download

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

Liz Arangio
Director of Gas Supply Planning
Telephone: 617-212-1790

MaryBeth Carroll
Manager of Gas Supply Planning
Telephone: 516-545-3116

Samara Jaffe
Director of Gas Contracting, Compliance & Hedging
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist of FERC Compliance & Contracting
Telephone: 516-545-5463

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Form of Transaction Confirmation – Package 5
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposal for Asset Management Arrangements dated July 20, 2021. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer dated________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***The terms of this Transaction Confirmation are binding upon execution hereof by both parties.***

Seller:	**Buyer:**
Attn: ______________________ Phone: ______________________ Fax: ______________________	The Narragansett Electric Company 100 East Old Country Road Hicksville, New York 11801 Attn: Contract Administration Phone: (516) 545-6068 Base Contract No. Transporter: Millennium Pipeline Company, L.L.C. ("Millennium"} Transporter Contract Number: 210165 Trader: Samara Jaffe

Contract Price: See Special Conditions below.

Term: Begin: November 1, 2021 End: October 31, 2022

Performance Obligation and Contract Quantity: See Special Conditions Below.

Delivery Point(s): The Delivery Point(s) shall be the point of interconnect between Millennium and Algonquin Gas Transmission Pipeline ("AGT") at Ramapo-AGT, into Buyer's capacity on AGT.,

Special Conditions:

A. Definitions
"Assets" means the released portion of Buyer's Millennium Contract No. 210165, having primary points of receipt at Corning-Empire PL and primary firm delivery entitlements to Ramapo-AGT.

"CFTC" shall mean the U.S. Commodity Futures Trading Commission.

"Credit Support Provider" shall mean _____________.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"EBB" means Buyer's Electronic Bulletin Board utilized for confirmation of Gas.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Services, Inc. or its successor.

"S&P" means S&P Global Ratings, or its successor.

B. Gas Service and Release of Assets

1. **Release of Assets:** During the Term, Buyer shall release at no cost to Seller, 5,000 dth/day (the "MDQ") of its Firm Transportation Contract No. 210165 with Millennium having a primary point of receipt of Corning-Empire PL and primary firm delivery entitlements to Ramapo AGT.

   Buyer shall remain responsible for payment of all demand charges related to the Assets (except any potential loss of discount related to activities of Seller). Seller shall be responsible for all variable costs in connection with the Assets during the Term. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

2. **Gas Supply Requirements:** On any day during the period of November 1, 2021 through April 30, 2022 ("Delivery Period") of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Points. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

   (a) At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this Delivery Period.

   (b) Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

3. **Termination Option:** If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Price: The commodity price for Gas purchased pursuant to Special Condition 2 shall be as follows:

(a) For Gas purchased pursuant to Special Condition 2 or 2(b) (i.e., called on through the exercise of a daily call) the price shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point(s).

(b) For Gas purchased through the Base-Load option pursuant to Special Condition 2(a), the price shall be equal to *Platts Inside FERC* for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point(s).

(c) Notwithstanding the foregoing, if in Buyer's sole discretion operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate this Transaction Confirmation.

B. Nominations

For Daily Calls at the Delivery Point(s) purchase pursuant to Special Condition 2, Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

C. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the Assets for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $_______________, payable in equal monthly installments of $ _______. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month.

D. Credit Provisions

Independent Amount. In the event Seller (i) has a credit rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to National Grid, (ii) the amount of Cash held by National Grid as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of National Grid ("Letter of Credit"), and (iii) the undrawn value of each Letter of Credit; provided, however, that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller has a Credit rating of at least BBB- from S&P and/or Baa3 from Moody's, and (ii) no Event of Default with respect to Seller has occurred and is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- from S&P and/or Baa3 from Moody's, (b) cash, or (c) a Letter of Credit. The "Collateral Requirement" for National Grid means zero (0).

Exposure. shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

E. Asset Management Arrangement ("AMA")

It is the intention of the parties to structure this transaction as an AMA as defined by the FERC in Order 712 (as modified and clarified) and in accordance with FERC's rules and regulations. Seller is acting as an Asset Manager as defined in 18 CFR 284.8(h)(3). If it is determined that this transaction does not constitute an AMA, the parties agree to modify the transaction as required while maintaining, to the extent possible, the economics of the transaction.

F. Changes in Law

If the FERC , the CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Transaction Confirmation or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other or either party may terminate this Transaction Confirmation upon Notice to the other party.

Seller:	Buyer: The Narragansett Electric Company
By: ______________________________	By: ______________________________
Name:	Name: James G. Holodak, Jr.
Title:	Title: Vice President
Date:	Date:

Attachment GSP-9

Attachment GSP-9

RFP for Everett Supply

nationalgrid

Request for Proposals ("RFP") for
Gas Supply
July 20, 2021

The Narragansett Electric Company ("Narragansett") is seeking proposals ("Proposals") for Gas Supplies into its firm transportation capacity on Tennessee Gas Pipeline ("TGP") in Zone 6. The winning bidder(s) ("Seller(s)") shall deliver the required gas supply to Narragansett at the Delivery Point.

Package No. 7 – Gas Supply - Everett

I. Gas Supply Requirements

Term: December 1, 2021 through March 31, 2022.

Delivery Point: The Delivery Point shall be the interconnection between the facilities of Constellation LNG, LLC at Everett, MA and Narragansett's firm transportation agreement with TGP.

Bidders wishing to deliver to alternative delivery points must indicate so with their offer; an awarded bidder will not be allowed to deliver to alternative delivery points without prior permission from Narragansett.

Quantity: Daily Call: The maximum daily quantity shall be up to 5,000 dt/day ("MDQ") and the maximum seasonal quantity ("MSQ") shall be 100,000 dt.

Bidders wishing to submit offers less than the MDQ may adjust the MSQ of both proportionately.

Price: Commodity Charge:
Pricing for the Daily Call quantities shall be based on *Platts Gas Daily* – Daily Price Survey ($MMBtu) Midpoint index for TGP Zone 6 North Point for the applicable Day.

	NOTE: Bidders may propose alternative index-based pricing with their bids but are advised that Buyer is unable to consider proposals which may be regarded as a fixed price contract, including those proposals containing a price floor. Reservation Charge: To be proposed by Seller.
Nominations:	Buyer shall make all nominations for delivery of Gas prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Nominations need not be ratable.

II. Instructions to Bidders

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals must include: **(a) Seller's proposed Price (including Reservation Charge), (b) any specialized language Seller requires in the Transaction Confirmation pertaining to the FERC or to the CFTC, and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

III. Schedule (all times are Eastern Standard Time)

July 30, 2021	Proposals must be received by National Grid by 5:00 PM. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 6, 2021.**

IV. Miscellaneous

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgrid.com/document/83526/download

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

Liz Arangio
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Manager of Gas Supply Planning
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Director of Gas Contracting, Compliance & Hedging
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

Testimony of
Ryan M. Scheib

DIRECT TESTIMONY

OF

RYAN M. SCHEIB

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I. Introduction

Q. Please state your name and business address.

A. My name is Ryan M. Scheib and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am a Senior Analyst in the New England Pricing group of the New England Regulation department of National Grid USA Service Company, Inc. ("Service Company"). In this position, I am responsible for preparing various regulatory filings for submission to the Rhode Island Public Utilities Commission ("PUC") on behalf of The Narragansett Electric Company d/b/a National Grid (the "Company") and the Massachusetts Department of Public Utilities on behalf of Massachusetts Electric Company and Nantucket Electric Company (together, "Mass. Electric").

Q. Please provide your educational background.

A. I received a Bachelor of Science in Finance from University of Delaware in 2016.

Q. Please provide your professional background.

A. In 2016, I joined National Grid as an Associate Analyst in the New England Gas Pricing group and, in 2018, I was promoted to Analyst supporting the gas division of the

Company. In June 2021, I was promoted to Senior Analyst supporting the Company and Mass. Electric.

Q. Have you previously testified before the PUC or any other regulatory commissions?

A. Yes. I have testified before the PUC in support of the Company's Distribution Adjustment Charge ("DAC") filing in Docket Nos. 4955 and 5040, the 2020 Gas Cost Recovery filing in Docket No. 5066 and the Company's FY 2021 Gas Infrastructure, Safety, and Reliability Plan filing in Docket No. 4996.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to calculate the Gas Cost Recovery ("GCR") factors proposed for effect on November 1, 2021 for the following services: (1) firm sales service to customers in the Residential Non-Heating and Heating rate classes and firm sales customers in the Small, Medium, Large, and Extra-Large Commercial and Industrial ("C&I") rate classes; and (2) transportation services provided to Gas Marketers and the associated Gas Marketer Fixed Charges and factors.

Q. How is your testimony organized?

A. My testimony includes the following three general sections: I. Introduction; II. GCR Factor Development; and III. Bill Impacts.

Q. Are you including any attachments with your testimony?

A. Yes. I am sponsoring the following attachments to my testimony:

Attachment RMS-1	Proposed Gas Cost Recovery Factors
Attachment RMS-2	Annual GCR Reconciliation Filing
Attachment RMS-3	Projected Gas Cost Deferral Balances
Attachment RMS-4	Bill Impact Analysis
Attachment RMS-5	FT-2 Demand Rate
Attachment RMS-6	FT-2 Capacity Allocator Percentages
Attachment RMS-7	COVID Deferral

II. <u>GCR Factor Development</u>

Q. Please provide an overview of the development of the proposed GCR factors.

A. The proposed GCR factors reflect the load specific (High Load and Low Load) factors necessary for the Company to recover the projected gas costs allocated to firm sales customers for the period November 1, 2021 through October 31, 2022. As shown in the joint pre-filed direct testimony of the Company's witnesses for the Gas Supply Panel ("GSP") on Attachment GSP-1, firm sales customers' gross gas costs for the 12 months ending October 31, 2022 are projected to be approximately $175.5 million. In addition to these projected costs, the proposed GCR factors also include recovery of working capital costs, inventory financing costs, prior period reconciliations, impacts of hedging activities, liquefied natural gas ("LNG") operation and maintenance ("O&M") costs, and credits for FT-2 Market Storage Demand and costs allocated to the DAC factors. The table below summarizes the costs and credits included in the proposed 2021-22 GCR factors:

GCR Component	**Amount (millions)**	**Attachment**
Firm Gas Costs	$175.5	GSP-1
Hedging Impact	($20.7)	JMP-5
Working Capital Costs	$1.2	RMS-1, Page 2, Line (9) + Page 3, Line (6)
Inventory Financing Costs	$0.7	RMS-1, Page 3, Lines (9) + (10)
Prior Period Deferred Balance (Excludes the COVID Deferral)	$10.7	RMS-1, Page 2, Line (10) + Page 3, Line (7)
LNG O&M Costs	$1.1	RMS-1, Page 2, Line (8) + Page 3, Line (8)
FT-2 Marketer Storage Demand Costs	($2.9)	RMS-1, Page 2, Line (4)
Subtotal	$165.6	RMS-1, Page 2, Line (12) + RMS-1, Page 3, Line (12)
COVID Deferral Recovery	$4.9	RMS-1, Page 7, Line (43) and RMS-7, Page 1, Line (3)
Total	$170.5	

The proposed GCR factors are intended to recover approximately $170.5 million in net costs over the period November 1, 2021 through October 31, 2022.

Q. Please explain how the proposed GCR factors were developed.

A. The proposed GCR factors were developed based on the fixed and variable cost components as defined in the GCR clause of the Company's tariff, R.I.P.U.C. NG-GAS No. 101, Section 2, Gas Charge, Schedule A. Attachment RMS-1 provides a summary of the GCR fixed and variable gas cost components used to develop the rates for which the Company requests approval in this filing.

Q. How was the fixed cost component of the proposed GCR factors developed?

A. The fixed cost component includes all fixed costs related to the purchase, storage, and delivery of firm gas for High Load Factor and Low Load Factor customers. As shown in Attachment RMS-1, Page 2, the fixed cost component is developed by taking the total fixed costs, which are already reduced by capacity release credits, less any credits such as customers' share of credits earned through the operation of the Natural Gas Portfolio Management Plan ("NGPMP"), demand costs allocated to the DAC mechanism, if any, and storage demand costs billed to FT-2 Marketers. The FT-2 storage demand costs are calculated by multiplying the FT-2 Demand Charge rate by the forecast of storage and peaking maximum daily quantity ("MDQ") to be billed to FT-2 Marketers. Adjustments are also made for supply-related LNG costs, working capital costs, and prior period deferred fixed gas costs under/over-recovery balances. This results in total fixed gas costs of $78.3 million to be recovered over the period November 2021 through October 2022.

Finally, because the Company's gas supply resources are planned so that there is sufficient capacity to meet the needs of firm customers (excluding firm customers with capacity exempt status) under design winter conditions, the total fixed gas cost to be recovered from customers is allocated between High Load Factor and Low Load Factor customers. The allocation is based on the proportion of design winter use of these two groups of customers. The High Load and Low Load Factors for each group are developed using the allocated fixed gas cost to each group and dividing each amount by each group's projected throughput for the upcoming year. Accordingly, the proposed GCR fixed Low Load Factor is $2.8591 per dekatherm, while the proposed GCR fixed High Load Factor is $2.1261 per dekatherm, excluding the adjustment for uncollectible expense.

Q. In the calculation of the fixed cost, you mentioned that the total fixed cost excludes "demand costs allocated to the DAC mechanism, if any." Is the Company proposing any demand costs to be allocated to the DAC?

A. Yes. As indicated in the direct testimony of the GSP, the Company has proposed to recover the costs of peaking assets needed for design hour reliability from all customers directly via the DAC. Therefore, the Company is proposing to allocate approximately $6.7 million associated with hourly peaking demand costs to the DAC mechanism to be recovered through the DAC factors proposed for effect November 1, 2021. These costs would include third-party portable LNG equipment and services at the former Cumberland LNG tank location and Old Mill Lane on Aquidneck Island, citygate deliveries on the Algonquin pipeline, LNG trucking, and a portion of the Company's Everett transportation and Everett Supply deal. These costs are reflected on Schedule GSP-1 in this filing.

Q. How did the Company develop the 2021-22 throughput forecast used to calculate the High Load and Low Load GCR Factors?

A. The pre-filed joint direct testimony of Company witnesses Theodore E. Poe, Jr. and Shira Horowitz supports the 2021-22 throughput forecast used to develop the proposed GCR factors.

Q. Has the Company included a reconciliation of Marketer fixed costs in this year's GCR filing?

A. No. As described in the pre-filed testimony of Elizabeth D. Arangio and MaryBeth M. Carroll in Docket No. 5067, the Company implemented changes to its Customer Choice program effective November 1, 2020, which eliminated the pipeline capacity release path marketer preference methodology. Therefore, the Company is no longer including a reconciliation of Marketer fixed costs in its GCR filings.

Q. Please describe the calculation of the design sales forecast.

A. As done last year in Docket No. 5066, the Company calculated the monthly design sales forecast by applying a monthly heat factor to the monthly design degree days. The monthly heat factor was computed by dividing the heating component of the normal sales (normal sales less monthly base use) by normal degree days for each month during the period November 2021 through March 2022. To compute the monthly design sales, the Company summed the monthly base use and the product of the monthly heat factor multiplied by the monthly design degree days. In Attachment RMS-1, Pages 14 through 16, the Company has provided detailed calculations showing the derivation of the monthly design sales.

Q. How did the Company develop the variable cost component of the proposed GCR factors?

A. The variable cost component includes all variable costs of gas such as commodity costs, supply-related LNG O&M, working capital, inventory finance costs, pipeline refunds, and deferred cost balances, and excludes variable costs allocated to the DAC mechanism, if any. As shown in Attachment RMS-1, Page 3, Line (12), the total estimated variable cost for the period November 2021 through October 2022 is $87.4 million. The variable costs are divided by the projected throughput to obtain a variable cost factor of $3.1703 per dekatherm.

Q. With respect to the calculation of the variable cost, you mentioned that the total variable cost excludes "variable costs allocated to the DAC mechanism, if any." Is the Company proposing any change to the variable costs allocated to the DAC?

A. No. The Company has conducted an engineering study and has determined that it is not necessary to allocate any variable costs to the DAC mechanism for effect November 1, 2021.

Q. Has the Company included any incremental variable costs associated with peaking assets needed for design hour reliability to be allocated to the DAC?

A. No. In Docket No. 5040, the Division recommended the Company include incremental variable cost associated with peak hour resources in the DAC if those costs are significant, and to report those costs in the next year's DAC and GCR filing, if found to be significant.[1] The Company has found that the incremental variable costs associated with peaking assets needed for design hour reliability were not significant; therefore, the Company is not including any incremental variable costs in this filing.

Q. What is the Company's estimate of the deferred gas cost balance at the end of the current GCR period?

A. Based on actual data through July 2021 and forecasted data for the months of August through October 2021, the total estimated deferred balance at October 31, 2021 is an

[1] R.I.P.U.C. Docket No. 5040/5066, Public Utilities Commission Order (01/05/2021), Page 5.

under-recovery of approximately $10.7 million, consisting of a fixed cost deferral of $3.6 million and a variable cost deferral of $7.1 million, as shown in Attachment RMS-1, Page 7, column (n), Lines (17) and (35). The Company also deferred a portion of its GCR increase from Docket No. 5066, which it implemented in the form of a per-therm reduction to the GCR factors it had proposed, resulting in an estimated COVID Deferral of $4.9 million, as shown in Attachment RMS-1, Page 7, column (n), Line (43). The total amount deferred for recovery beginning November 1 of $15.6 million is incorporated into the development of the proposed GCR factors for the period November 1, 2021 to October 31, 2022. In addition, the Company shows the projected monthly deferred gas cost balances for November 2021 through October 2022 in Attachment RMS-3.

Q. What is the COVID Deferral and the Company's recovery proposal?

A. In Docket No. 5066, the PUC ordered the Company to defer 50 percent of its proposed revenue increase associated with the GCR to mitigate the bill impact on customers as a form of relief in light of the economic hardship that many had faced as a result of the global pandemic. The Company is proposing COVID Deferral Recovery factors in this filing that are designed to recover the estimated deferral at October 31, 2021 associated with the 50 percent of the 2020-21 GCR increase that it did not recover from sales customers.

Q. Please describe the Company's calculation of COVID Deferral amount to be recovered from customers.

A. In last year's GCR filing in Docket No. 5066, the Company proposed an increase in recovery of $10.6 million compared to the prior year. However, in accordance with the PUC ruling in that proceeding, the Company reduced its proposed GCR factors and deferred the recovery of 50 percent of this increase, or $5.3 million. Specifically, the $5.3 million COVID Deferral was allocated to the High Load and Low Load rate classes to calculate the per-therm reduction to the High Load and Low Load GCR factors the Company was proposing effective November 1, 2020 (see Docket No. 5066, Compliance GCR Filing, Compliance Schedule RMS/MJP-8, Page 2, Lines (12) and (13), Column (g)). The Company then billed sales customers the lower GCR factors after the reduction for the COVID Deferral.

As seen on Schedule RMS-7, Page 2, the Company tracked the accumulation of the COVID Deferral (reduction to revenue) for Low Load and High Load each rate classes based on nine months of actual billing data (November 2020 through July 2021) and three months of forecasted data (August 2021 through October 2021), plus interest, to calculate the ending deferral balance for the period ending October 31, 2021 to be recovered for each rate class grouping. The total COVID Deferral the Company is proposing to be recovered is $4.9 million, and the COVID Deferral amounts to be recovered for High Load and Low Load customers are summarized on Schedule RMS-7, Page 1.

Q. How did the Company develop the COVID Deferral factors that it is proposing as a component of the proposed GCR factors?

A. As seen on Schedule RMS-7, Page 1, the Company divided the COVID Deferral ending under-recovery balance for the High Load and Low Load customer classes by the forecasted throughput for each rate class grouping. Schedule RMS-7 shows the proposed COVID Deferral Recovery factors per rate class.

Q. Attachment RMS-2 provides the fiscal year 2021 Annual GCR Reconciliation balances. Does the monthly information shown in Attachment RMS-2 correspond with the monthly deferred balance reports filed in Docket Nos. 4963 and 5066?

A. Yes. The March 31, 2021 reconciliation balance of $5,789,241 shown in Attachment RMS-2 reflects the balance that was submitted on July 1, 2021 in the Company's annual GCR reconciliation report and is the same balance reflected in the July 2021 monthly deferred balance report filed in Docket No. 5066 on August 20, 2021.

Q. Is the Company proposing any other rates in this filing?

A. Yes. Consistent with the modifications in Docket No. 4270, the Company is submitting for approval its FT-2 Marketer Demand rate of $12.2364 per MDQ in dekatherms per month, as shown in Attachment RMS-5, as well as the storage and peaking charge of $0.9605 per therm for FT-1 firm transportation customers returning to Transitional Sale Service ("TSS"). The Company is also requesting approval of the capacity assignment percentages for the High Load and Low Load Factors to be used in the determination of pipeline, underground storage, and peaking capacity for Marketers. These percentages are set forth in Attachment RMS-6. The Company has also provided the detail calculations of the capacity assignment percentages in an Excel file contained in the USB flash drive provided to the Division with this filing.

Q. How was the proposed FT-2 Marketer Demand rate calculated?

A. The FT-2 rate design approved in Docket No. 4270 separates storage costs into the following two components: (1) the FT-2 Demand rate designed to recover the fixed costs associated with storage and peaking, which the Company is submitting for approval in this filing; and (2) the FT-2 Variable rate that is designed to recover variable underground storage costs, as well as the associated commodity costs and loss factors associated with pipeline contracts to bring the gas from storage to the citygate. In addition, Marketers may purchase peaking inventory at the Company's cost of LNG inventory.

The FT-2 Demand rate is derived by first totaling the fixed storage costs, associated inventory finance, working capital charges, and supply-related LNG O&M costs, less any demand credits assigned to the DAC factors and any refunds, if applicable. That total is then divided by the total storage and peaking MDQ for the year to derive a monthly per dekatherm rate to be charged to Marketers. As shown in Attachment RMS-5, the proposed FT-2 Marketer Demand rate is $12.2364 per dekatherm and will be applied to the Marketers' storage and peaking MDQ.

III. <u>Bill Impacts</u>

Q. Is the Company presenting the impacts of its proposed rates for November 1, 2021 on customer bills in this filing?

A. Yes. The Company is presenting the bill impacts associated with its proposed GCR factors in this filing as well as its proposed DAC factors submitted in Docket No. 5165. The bill impacts are presented in Attachment RMS-4 and reflect current annual bills in Column (c) assuming that the rates in effect during September 2021 are effective for 12 months.

Q. What is the combined bill impact of the proposed GCR and DAC factors on customer bills as compared to bills over the past year?

A. An average Residential Heating customer using 845 therms per year will see a total annual bill of $1,478.21 based on the proposed GCR and DAC factors, which is an increase of $109.85, or 8.0 percent, from last year's bills. This overall increase is comprised of an increase of $64.30 as a result of the proposed GCR factors; an increase of $42.25 as a result of the proposed DAC factors as revised in a supplemental filing on September 1, 2021 in Docket No. 5165; and an increase of $3.30 in Gross Earnings Tax.

Q. What are the main drivers causing the increase presented in the bill impact analysis?

A. The annual residential heating bill increase is attributable to the following drivers:

	$ Inc (Dec)	**%**
Annual Bill at Current Rates	$1,368.36	
Recovery of DAC COVID Deferral	$48.67	3.6%
Net Decrease in DAC	($6.42)	(0.5%)
Recovery of GCR COVID Deferral	$31.43	2.3%
Increase re: Texas Eastern Transmission, LP Rate Case	$12.66	0.9%
Net Increase in Remaining GCR Components	$20.21	1.5%
Increase in Gross Earnings Tax	$3.30	0.2%
	$1,478.21	

Overall, the increase in an average residential heating customer's bill of $109.85, or 8.0 percent, is driven mostly by an increase of $80.10, or 5.9%, due to the recovery COVID deferral amounts that were not recovered through the 2020-2021 DAC and GCR factors.

Q. Does this conclude your testimony?

A. Yes.

<u>Attachments of Ryan M. Scheib</u>

Attachment RMS-1	Gas Cost Recovery Factors
Attachment RMS-2	Annual GCR Reconciliation Filing
Attachment RMS-3	Projected Gas Cost Balances
Attachment RMS-4	Bill Impact Analysis
Attachment RMS-5	FT-2 Demand Rate
Attachment RMS-6	FT-2 Capacity Allocator Percentages
Attachment RMS-7	COVID Deferral

Attachment RMS-1
Gas Cost Recovery Factors

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2021

	Description (a)	Source: Reference (b)	Source: Line # (c)	High Load[1] (d)	Low Load[2] (e)	FT-2 Mkter[3] (f)
(1)	Fixed Cost Factor - $/dktherm	RMS-1, pg 2	Line (16)	$2.1261	$2.8591	
(2)	Variable Cost Factor -$/dktherm	RMS-1, pg 3	Line (14)	$3.1703	$3.1703	
(3)	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$5.2964	$6.0294	
(4)	Uncollectible %	Docket 4770		1.91%	1.91%	
(5)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) ÷ [1 - (4)]		$5.3995	$6.1468	
(6)	GCR Charge on a per therm basis	(5) ÷ 10		$0.5399	$0.6146	
(7)	COVID Deferral Factor per therm	RMS-7, pg 1	[Line (1) & (2)] ÷ 10	$0.0153	$0.0177	
(8)	GCR Charge on a per therm basis	(6) + (7)		**$0.5552**	**$0.6323**	
(9)	Current rate effective 11/01/20 - $/therm	Docket 5066		$0.4940	$0.5562	
(10)	Increase / (Decrease) - $/therm	(8) - (9)		$0.0612	$0.0761	
(11)	Percent Increase	(9) ÷ (8)		12.4%	13.7%	

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load
[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load
[3] See RMS-5 for calculation of FT-2 rate
(6): Truncated to 4 decimals.

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Fixed Cost Calculation ($ per Dth)

	Description	Source: Reference	Source: Line #	Amount	High Load Factor Total	Low Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Costs (net of Cap Rel to marketers)	RMS-1, pg 5	Line (41)	$90,887,120		
	Less:					
(2)	NGPMP Customer Benefit	GSP-1		($8,039,179)		
(3)	Interruptible Costs			$0		
(4)	FT-2 Storage Demand Costs	RMS-5, pg 2	Line (25)	($2,880,020)		
(5)	System Pressure to DAC	GSP-1, pg 12		($6,685,226)		
(6)	Refunds			$0		
(7)	Total Credits	Sum[(2):(6)]		($17,604,425)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Dkt 4770	Compliance Attachment 2 Schedule 32 Pg 5	$829,823		
(9)	Working Capital Requirement	RMS-1, pg 9	Line (16)	$620,254		
(10)	Deferred Fixed Cost Under-recovered	RMS-1, pg 7	Line (17)	$3,569,594		
(11)	Total Additions	Sum[(8):(10)]		$5,019,671		
(12)	Total Fixed Costs	(1) + (7) + (11)		$78,302,365		
(13)	Design Winter Sales Percentage	RMS-1, pg 13	Lines (10) & (11)		1.78%	98.22%
(14)	Allocated Supply Fixed Costs	(12) x (13)			$1,393,782	$76,908,583
(15)	Sales (Dth) Nov 2020 - Oct 2021	RMS-1, pg 12	Line (9)	27,554,528	655,553	26,898,975
(16)	Fixed Factor	(14) ÷ (15)			**$2.1261**	**$2.8591**

(15) Col (e): RMS-1 page 12, Sum[Lines (1), (6), (8)]
Col (f): RMS-1 page 12, Sum[Lines (2)-(5), (7)]

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Variable Cost Calculation ($ per Dth)

	Description	Source: Reference	Source: Line #	Amount
	(a)	(b)	(c)	(d)
(1)	Variable Costs, excluding Refunds	RMS-1, pg 6	Line (77) - Line (74)	$78,612,614
	Less:			
(2)	System Pressure to DAC			$0
(3)	Non-Firm Sales			$0
(4)	Refunds	RMS-1, pg 6	Line (74)	$0
(5)	Total Credits	Sum [(2):(4)]		$0
	Plus:			
(6)	Working Capital	RMS-1, pg 9	Line (32)	$579,082
(7)	Deferred Variable Cost Under-recovered	RMS-1, pg 7	Line (35)	$7,128,552
(8)	Supply Related LNG O&M	Docket 4770	Compliance Attachment 2 Schedule 32 Pg 5 Ln 15 - Ln 12	$302,244
(9)	Inventory Financing - LNG	RMS-1, pg 11	Line (22)	$267,879
(10)	Inventory Financing - Storage	RMS-1, pg 11	Line (12)	$468,035
(11)	Total Additions	Sum [(6):(10)]		$8,745,793
(12)	Total Variable Supply Costs	(1) + (5) + (11)		$87,358,407
(13)	Sales (Dth) Nov 2020 - Oct 2021	RMS-1, pg 12	Line (9)	27,554,528
(14)	Variable Cost Factor	(12) ÷ (13)		**$3.1703**

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

	Description (a)	Reference (b)	Nov-21 (c)	Dec-21 (d)	Jan-22 (e)	Feb-22 (f)	Mar-22 (g)	Apr-22 (h)	May-22 (i)	Jun-22 (j)	Jul-22 (k)	Aug-22 (l)	Sep-22 (m)	Oct-22 (n)	Nov-Oct (o)
	Supply Fixed Costs - Pipeline Delivery														
(1)	Dawn to E Here	GSP-1	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$1,112,092	$13,345,099
(2)	Dawn to WADDY	GSP-1	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$25,511	$306,138
(3)	Dominion SP	GSP-1	$7,119	$7,119	$7,119	$7,708	$7,708	$7,708	$7,708	$7,708	$7,708	$7,708	$7,708	$7,708	$90,725
(4)	Dracut	GSP-1	$83,636	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$1,018,900
(5)	Everett	GSP-1	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$104,545	$1,254,540
(6)	Manchester Lateral	GSP-1	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$209,627	$2,515,522
(7)	Millennium/AIM	GSP-1	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$760,234	$9,122,812
(8)	Niagara	GSP-1	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$80,610
(9)	TCO (Pool)	GSP-1	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$703,059	$8,436,708
(10)	AGT M3	GSP-1	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$1,521,482
(11)	TETCO SCT Long Haul	GSP-1	$17,889	$17,889	$17,889	$25,971	$25,971	$25,971	$25,971	$25,971	$25,971	$25,971	$25,971	$25,971	$287,402
(12)	TETCO CDS Long Haul	GSP-1	$1,000,079	$1,000,079	$1,000,079	$1,455,931	$1,455,931	$1,455,931	$1,455,931	$1,455,931	$1,455,931	$1,455,931	$1,455,931	$1,455,931	$16,103,620
(13)	Transco Leidy	GSP-1	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$9,423	$113,074
(14)	Yankee Interconnect	GSP-1	$46,961	$46,961	$42,961	$42,961	$42,961	$42,961	$42,961	$42,961	$42,961	$42,961	$42,961	$42,961	$523,538
(15)	TGP Long Haul	GSP-1	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$451,553	$5,418,632
(16)	TGP ConneXion	GSP-1	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$215,979	$2,591,749
(17)	AMA Credits	GSP-1	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($125,155)	($1,501,864)
(18)	Less Credits from Mkter Releases*	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Total Supply Fixed Costs - Pipeline	Sum[(1):(18)]	$4,756,059	$4,757,447	$4,753,447	$5,217,970	$5,217,970	$5,217,970	$5,217,970	$5,217,970	$5,217,970	$5,217,970	$5,217,970	$5,217,970	$61,228,685
	Storaged Fixed Costs - Facilities														
(20)	Columbia FSS	GSP-1	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$278,385
(21)	Dominion GSS	GSP-1	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$436,941
(22)	Dominion GSSTE	GSP-1	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$561,478
(23)	Providence LNG	GSP-1	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$3,486,240
(24)	Tennessee FSMA	GSP-1	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$507,760
(25)	Tetco FSS1	GSP-1	$3,502	$3,502	$3,502	$4,722	$4,722	$4,722	$4,722	$4,722	$4,722	$4,722	$4,722	$4,722	$53,002
(26)	Tetco SS1	GSP-1	$132,098	$131,995	$131,995	$191,183	$191,183	$191,183	$191,183	$191,183	$191,183	$191,183	$191,183	$191,183	$2,116,736
(27)	Total Fixed Storage Costs	Sum[(20):(26)]	$574,834	$574,730	$574,730	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$7,440,542

* Capacity release credits included in forecasted supply costs

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-21 (c)	Dec-21 (d)	Jan-22 (e)	Feb-22 (f)	Mar-22 (g)	Apr-22 (h)	May-22 (i)	Jun-22 (j)	Jul-22 (k)	Aug-22 (l)	Sep-22 (m)	Oct-22 (n)	Nov-Oct (o)
Storage Fixed Costs - Delivery														
(28) Storage Delivery	GSP-1	$461,954	$461,954	$461,954	$485,292	$485,292	$454,466	$454,466	$454,466	$454,466	$454,466	$454,466	$454,466	$5,537,709
(29) LNG	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(30) Proposed CNG/LNG	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(31) Everett Supply Deal	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(32) Dracut Supply Deal	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(33) Everett Supply Deal2	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(34) Summer Liquid Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(35) Summer Trucking	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(36) AGT Citygate	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(37) Winter Trucking	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(38) Proposed Summer Liquid	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(39) Storage Delivery Fixed Cost	Sum[(28):(38)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(40) Total Storage Fixed	(27) + (39)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(41) Total Fixed Costs	(19)+(27)+(39)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$90,887,120

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-21 (c)	Dec-21 (d)	Jan-22 (e)	Feb-22 (f)	Mar-22 (g)	Apr-22 (h)	May-22 (i)	Jun-22 (j)	Jul-22 (k)	Aug-22 (l)	Sep-22 (m)	Oct-22 (n)	Nov-Oct (o)
Variable Commodity Costs														
(42) AGT Citygate	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(43) AIM at Ramapo	GSP-1	$31,614	$7,989	$100,784	$93,545	$31,422	$48,532	$0	$0	$0	$0	$0	$10,802	$324,688
(44) Const Summer Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(45) Const Winter Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(46) Dawn via IGTS	GSP-1	$0	$20,859	$72,157	$68,224	$0	$0	$0	$0	$0	$0	$0	$0	$161,240
(47) Dawn via PNGTS	GSP-1	$98,210	$860,230	$2,089,085	$1,891,700	$984,087	$11,576	$0	$0	$0	$0	$0	$0	$5,934,888
(48) Dominion SP	GSP-1	$55,453	$60,866	$62,174	$55,605	$58,031	$0	$41,460	$40,550	$41,732	$0	$35,424	$36,588	$487,883
(49) Dracut Supply	GSP-1	$0	$0	$0	$0	$0	$0	$457,282	$287,382	$0	$0	$187,437	$0	$932,100
(50) Everett Long-Term	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(51) Everett Swing	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(52) Millennium	GSP-1	$747,985	$821,010	$838,644	$750,039	$782,765	$153,552	$559,249	$546,971	$562,913	$548,485	$477,824	$493,522	$7,282,959
(53) Niagara	GSP-1	$11,875	$113,371	$126,251	$80,202	$32,245	$91,310	$0	$0	$0	$0	$0	$0	$455,253
(54) TCO Appalachia	GSP-1	$1,514,033	$3,765,787	$3,877,226	$3,484,655	$3,287,924	$253,670	$132,969	$6,582	$130,604	$129,575	$78,210	$52,147	$16,713,382
(55) Tetco M3	GSP-1	$240,618	$143,487	$623,151	$306,358	$744,288	$4,477,765	$1,867,289	$1,090,382	$0	$0	$13,696	$970,722	$10,477,754
(56) Transco Leidy	GSP-1	$34,897	$67,008	$136,893	$108,798	$90,721	$7,803	$5,379	$5,251	$5,367	$5,231	$4,589	$42,564	$514,501
(57) Waddington	GSP-1	$0	$401	$871	$285	$32,859	$0	$0	$0	$0	$0	$0	$0	$34,417
(58) Nextera Summer Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(59) Tetco M2 CDS	GSP-1	$3,756,607	$4,138,098	$4,412,486	$3,825,613	$3,977,602	$148,341	$1,036,971	$638,157	$1,920,435	$1,897,707	$1,853,302	$2,369,704	$29,975,022
(60) Tetco M2 SCT	GSP-1	$0	$31,752	$113,280	$98,875	$11,858	$0	$0	$0	$0	$0	$0	$0	$255,765
(61) TGP Z4 Cnx	GSP-1	$705,579	$966,245	$1,156,665	$1,027,059	$918,643	$538,589	$773,946	$293,409	$627,983	$802,721	$706,780	$731,526	$9,249,144
(62) TGP Z4 LH	GSP-1	$1,293,120	$1,596,670	$2,549,703	$2,286,491	$1,386,688	$630,637	$0	$0	$0	$151,408	$0	$519,172	$10,413,889
(63) Proposed Summer Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(64) Total Variable Commodity Costs	Sum[(42) (63)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Storage Costs														
(65) Underground Storage	GSP-1	$1,006,002	$2,268,603	$2,441,573	$2,245,611	$1,481,955	$192,438	$0	$0	$0	$0	$0	$0	$9,636,182
(66) LNG Withdrawals and Trucking	GSP-1	$84,843	$87,768	$534,395	$398,408	$90,365	$88,559	$91,391	$88,256	$91,049	$90,946	$87,913	$90,750	$1,824,641
(67) Total Variable Storage Costs	(65) + (66)	$1,090,844	$2,356,371	$2,975,968	$2,644,019	$1,572,320	$280,997	$91,391	$88,256	$91,049	$90,946	$87,913	$90,750	$11,460,823
Variable Transportation Costs														
(68) Variable Costs for Purchases to City Ga	GSP-1	$207,776	$260,883	$324,500	$315,220	$285,542	$86,185	$42,640	$29,649	$55,547	$59,070	$74,942	$134,715	$1,876,669
(69) Variable Cost for Storage Withdrawal	GSP-1	$43,468	$99,296	$102,126	$94,558	$53,470	$4,737	$0	$0	$0	$0	$0	$0	$397,655
(70) Variable Cost for Storage Injection	GSP-1	$26,603	$0	$0	$0	$132,167	$52,020	$55,859	$36,160	$70,133	$46,420	$66,945	$65,534	$551,841
(71) Total Variable Transportation Costs	Sum[(68):(70)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injections														
(72) Cost of Injections	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(73) Variable Cost for Storage Injection	GSP-1	($26,603)	$0	$0	$0	($132,167)	($52,020)	($55,859)	($36,160)	($70,133)	($46,420)	($66,945)	($65,534)	($551,841)
(74) Refunds	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(75) Total Injections	Sum[(72):(74)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Impact														
(76) Hedging Impact	JMP-5	($2,494,992)	($3,116,104)	($3,521,325)	($3,018,095)	($2,512,023)	($1,240,010)	($1,115,646)	($872,167)	($676,698)	($574,487)	($732,258)	($806,750)	($20,680,555)
(77) Total Variable Costs	(64)+(67)+(71)+(75)+(76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$78,612,614
(78) Total Supply Costs	(41) + (77)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$169,499,735
Storage Costs for FT-2 Calculation														
(79) Storage Fixed Costs - Facilities	(27)	$574,834	$574,730	$574,730	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$635,139	$7,440,542
(80) Storage Fixed Costs - Deliveries	(39)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(81) Total Storage Costs	(79) + (80)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
GCR Deferred Balances

	Description	Nov-20 actual	Dec-20 actual	Jan-21 actual	Feb-21 actual	Mar-21 actual	Apr-21 actual	May-21 actual	Jun-21 actual	Jul-21 actual	Aug-21 forecast	Sep-21 forecast	Oct-21 forecast	Nov-Oct
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	I Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	$6,235,963	$7,685,937	$7,128,094	$1,076,203	($5,082,948)	($11,636,525)	($13,864,154)	($13,168,237)	($10,294,563)	($6,558,105)	($2,976,290)	$553,344	$6,235,963
(4)	Supply Fixed Costs (net of cap rel)	$6,172,559	$8,866,638	$8,836,970	$9,180,189	$9,050,245	$5,642,607	$5,545,613	$5,818,330	$5,462,123	$5,874,894	$5,874,894	$5,874,894	$82,199,954
(5)	Supply Related System Pressure to DAC	($20,574)	($1,305,540)	($1,242,058)	($1,252,572)	($1,147,240)	($5,414)	($20,574)	($20,574)	($20,574)	($20,909)	($20,909)	($20,909)	($5,097,849)
(6)	Supply Related LNG O&M	$69,152	$69,152	$69,152	$69,152	$115,939	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$876,610
(7)	NGPMP Credits	($437,588)	($437,588)	($1,338,739)	($437,588)	($3,167,524)	($437,588)	($437,588)	($437,588)	($105,189)	($437,588)	($437,588)	($437,588)	($8,549,740)
(8)	Working Capital	$46,538	$57,197	$57,453	$59,970	$59,784	$42,644	$41,795	$43,858	$41,164	$44,284	$44,284	$44,284	$583,254
(9)	Total Supply Fixed Costs	$5,830,086	$7,249,859	$6,382,779	$7,619,152	$4,911,204	$5,311,400	$5,198,398	$5,473,178	$5,446,675	$5,529,833	$5,529,833	$5,529,833	$70,012,229
(10)	Supply Fixed - Revenue	$4,198,905	$7,815,561	$12,439,023	$13,776,383	$11,455,910	$7,525,937	$4,488,139	$2,587,457	$1,701,276	$1,942,960	$1,998,955	$2,515,771	$72,446,275
(11)	Monthly Under/(Over) Recovery	$1,631,181	($565,703)	($6,056,244)	($6,157,231)	($6,544,706)	($2,214,537)	$710,259	$2,885,721	$3,745,399	$3,586,873	$3,530,878	$3,014,062	($2,434,046)
(12)	Prelim Ending Under/(Over) Recovery	$7,867,144	$7,120,235	$1,071,850	($5,081,028)	($11,627,655)	($13,851,061)	($13,153,895)	($10,282,516)	($6,549,164)	($2,971,232)	$554,588	$3,567,406	$3,801,917
(13)	Month's Average Balance	$7,051,554	$7,403,086	$4,099,972	($2,002,413)	($8,355,301)	($12,743,793)	($13,509,025)	($11,725,377)	($8,421,863)	($4,764,668)	($1,210,851)	$2,060,375	
(14)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(15)	Interest Applied	$7,245	$7,859	$4,353	($1,920)	($8,870)	($13,093)	($14,342)	($12,047)	($8,941)	($5,058)	($1,244)	$2,187	($43,871)
(16)	Marketer Reconcilation	($188,452)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($188,452)
(17)	Fixed Ending Under/(Over) Recovery	$7,685,937	$7,128,094	$1,076,203	($5,082,948)	($11,636,525)	($13,864,154)	($13,168,237)	($10,294,563)	($6,558,105)	($2,976,290)	$553,344	$3,569,594	$3,569,594
(18)	II Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$5,896,957	$7,145,258	$11,196,560	$13,753,077	$16,711,897	$14,095,362	$11,279,428	$9,200,801	$8,449,829	$8,544,732	$7,594,211	$6,519,923	$5,896,957
(20)														
(21)	Variable Supply Costs	$5,716,480	$11,965,664	$15,388,563	$17,212,370	$9,216,169	$4,842,056	$2,380,847	$1,654,565	$1,559,313	$771,383	$699,327	$2,903,652	$74,310,390
(22)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23)	Supply Related LNG O&M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(24)	Inventory Financing - LNG	$23,751	$23,050	$22,804	$22,275	$22,830	$22,641	$22,543	$22,448	$22,114	$21,135	$21,966	$21,957	$269,513
(25)	Inventory Financing - UG	$74,899	$68,025	$58,259	$49,740	$42,819	$43,664	$45,398	$44,966	$47,761	$49,236	$60,093	$70,944	$655,805
(26)	Working Capital	$43,243	$90,517	$116,410	$130,206	$69,717	$36,629	$18,010	$12,516	$11,796	$5,835	$5,290	$21,965	$562,135
(27)	Total Supply Variable Costs	$5,883,560	$12,172,442	$15,611,223	$17,439,779	$9,376,722	$4,970,176	$2,491,986	$1,759,682	$1,666,170	$872,777	$811,864	$3,043,706	$76,100,087
(28)	Supply Variable - Revenue	$4,690,905	$8,130,870	$13,067,943	$14,495,558	$12,009,601	$7,799,139	$4,581,479	$2,519,717	$1,580,284	$1,831,860	$1,893,399	$2,442,317	$75,043,071
(29)	Monthly Under/(Over) Recovery	$1,192,655	$4,041,571	$2,543,280	$2,944,220	($2,632,879)	($2,828,962)	($2,089,493)	($760,034)	$85,887	($959,083)	($1,081,535)	$601,389	$1,057,015
(30)	Prelim Ending Under/(Over) Recovery	$7,089,612	$11,186,829	$13,739,840	$16,697,297	$14,079,018	$11,266,400	$9,189,935	$8,440,766	$8,535,716	$7,585,649	$6,512,676	$7,121,311	$6,953,973
(31)	Month's Average Balance	$6,493,285	$9,166,043	$12,468,200	$15,225,187	$15,395,457	$12,680,881	$10,234,682	$8,820,784	$8,492,772	$8,065,191	$7,053,444	$6,820,617	
(32)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(33)	Interest Applied	$6,671	$9,731	$13,237	$14,599	$16,344	$13,028	$10,866	$9,062	$9,016	$8,562	$7,247	$7,241	$125,606
(34)	Gas Procurement Incentive/(penalty)	$48,974	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$48,974
(35)	Variable Ending Under/(Over) Recovery	$7,145,258	$11,196,560	$13,753,077	$16,711,897	$14,095,362	$11,279,428	$9,200,801	$8,449,829	$8,544,732	$7,594,211	$6,519,923	$7,128,552	$7,128,552
(36)	III COVID Deferral													
(37)	Beginning Balance	$0	$154,001	$693,790	$1,563,369	$2,528,850	$3,330,403	$3,852,884	$4,159,592	$4,331,097	$4,439,946	$4,566,128	$4,696,286	$0
(38)	COVID Cost Deferral	$153,922	$539,339	$868,382	$963,520	$798,445	$518,793	$302,457	$167,146	$104,195	$121,404	$125,402	$162,182	$4,825,186
(39)	Prelim Ending Balance	$153,922	$693,340	$1,562,172	$2,526,889	$3,327,295	$3,849,196	$4,155,341	$4,326,738	$4,435,293	$4,561,350	$4,691,530	$4,858,468	
(40)	Month's Average Balance	$76,961	$423,671	$1,127,981	$2,045,129	$2,928,072	$3,589,800	$4,004,113	$4,243,165	$4,383,195	$4,500,648	$4,628,829	$4,777,377	
(41)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(42)	Interest Applied	$79	$450	$1,198	$1,961	$3,109	$3,688	$4,251	$4,359	$4,653	$4,778	$4,756	$5,072	$38,354
(43)	COVID Deferral Ending Balance	$154,001	$693,790	$1,563,369	$2,528,850	$3,330,403	$3,852,884	$4,159,592	$4,331,097	$4,439,946	$4,566,128	$4,696,286	$4,863,540	$4,863,540
(44)	GCR Deferred Summary													
(45)	Beginning Under/(Over) Recovery	$12,132,920	$14,985,196	$19,018,444	$16,392,649	$14,157,799	$5,789,241	$1,268,158	$192,156	$2,486,364	$6,426,573	$9,184,049	$11,769,553	$12,132,920
(46)	Gas Costs	$11,774,351	$19,621,100	$23,077,814	$25,234,327	$17,260,300	$10,573,587	$8,000,225	$7,546,659	$7,095,200	$6,719,707	$6,647,651	$8,851,976	$152,402,897
(47)	Inventory Finance	$98,650	$91,074	$81,063	$72,015	$65,649	$66,305	$67,942	$67,414	$69,875	$70,371	$82,059	$92,901	$925,318
(48)	Working Capital	$89,781	$147,714	$173,863	$190,176	$129,501	$79,272	$59,806	$56,375	$52,959	$50,119	$49,574	$66,249	$1,145,389
(49)	NGPMP Credits	($437,588)	($437,588)	($1,338,739)	($437,588)	($3,167,524)	($437,588)	($437,588)	($437,588)	($105,189)	($437,588)	($437,588)	($437,588)	($8,549,740)
(50)	Total Costs	$11,525,194	$19,422,300	$21,994,002	$25,058,930	$14,287,926	$10,281,577	$7,690,384	$7,232,860	$7,112,845	$6,402,610	$6,341,697	$8,573,538	$145,923,864
(51)	Revenue	$8,735,887	$15,407,093	$24,638,584	$27,308,421	$22,667,067	$14,806,283	$8,767,161	$4,940,028	$3,177,364	$3,653,416	$3,766,952	$4,795,906	$142,664,160
(52)	Monthly Under/(Over) Recovery	$2,789,307	$4,015,207	($2,644,582)	($2,249,491)	($8,379,141)	($4,524,706)	($1,076,777)	$2,292,832	$3,935,481	$2,749,194	$2,574,745	$3,777,633	$3,259,703
(53)	Prelim Ending Under/(Over) Recovery	$14,922,227	$19,000,403	$16,373,862	$14,143,158	$5,778,658	$1,264,534	$191,381	$2,484,988	$6,421,845	$9,175,767	$11,758,794	$15,547,185	$15,392,623
(54)	Month's Average Balance	$13,527,574	$16,992,800	$17,696,153	$15,267,904	$9,968,228	$3,526,887	$729,770	$1,338,572	$4,454,104	$7,801,170	$10,471,422	$13,658,369	
(55)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(56)	Interest Applied	$13,995	$18,040	$18,787	$14,640	$10,583	$3,624	$775	$1,375	$4,729	$8,282	$10,758	$14,500	$120,088
(57)	Gas Purchase Plan Incentives/(Penalties)	$48,974	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$48,974
(58)	Ending Under/(Over) Recovery W/ Interest	$14,985,196	$19,018,444	$16,392,649	$14,157,799	$5,789,241	$1,268,158	$192,156	$2,486,364	$6,426,573	$9,184,049	$11,769,553	$\boxed{\$15,561,686}$	$15,561,686

Source: Docket No 5066 filed on August 20, 2021

REDACTED

The Narragansett Electric Company
d/b/a National Grid
Docket No 5180
Attachment RMS-1
Page 8 of 16

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
GCR - Gas Cost Revenue

	Description (a)	Nov-21 fcst (b)	Dec-21 fcst (c)	Jan-22 fcst (d)	Feb-22 fcst (e)	Mar-22 fcst (f)	Apr-22 fcst (g)	May-22 fcst (h)	Jun-22 fcst (i)	Jul-22 fcst (j)	Aug-22 fcst (k)	Sep-22 fcst (l)	Oct-22 fcst (m)	Total Nov-Oct (n)
(1)	I Fixed Cost Revenue													
(2)	(a) Low Load dth	2,076,841	3,475,596	4,567,729	4,963,697	3,812,545	3,073,666	1,327,512	811,489	643,701	609,299	646,808	890,093	26,898,975
(3)	Fixed Cost Factor	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	$2 8591	
(4)	Low Load Revenue	$5,937,897	$9,937,077	$13,059,594	$14,191,705	$10,900,446	$8,787,920	$3,795,489	$2,320,129	$1,840,405	$1,742,046	$1,849,288	$2,544,865	$76,906,861
(5)	(b) High Load dth	56,086	69,723	80,698	81,548	71,399	63,479	44,779	40,352	35,916	34,975	35,650	40,947	655,553
(6)	Fixed Cost Factor	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	$2 1261	
(7)	High Load Revenue	$119,245	$148,238	$171,572	$173,379	$151,801	$134,962	$95,205	$85,792	$76,362	$74,361	$75,797	$87,057	$1,393,771
(8)	sub-total Dth	2,132,927	3,545,319	4,648,427	5,045,244	3,883,944	3,137,145	1,372,291	851,841	679,617	644,274	682,458	931,040	27,554,528
(9)	FT-2 Storage Revenue from marketers	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$240,002	$2,880,020
(10)	Total Fixed Revenue	$6,297,144	$10,325,317	$13,471,168	$14,605,086	$11,292,249	$9,162,884	$4,130,696	$2,645,923	$2,156,769	$2,056,409	$2,165,087	$2,871,924	$81,180,652
(11)	II Variable Cost Revenue													
(12)	(a) Firm Sales dth	2,132,927	3,545,319	4,648,427	5,045,244	3,883,944	3,137,145	1,372,291	851,841	679,617	644,274	682,458	931,040	27,554,528
(13)	Variable Cost Factor	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	$3 1703	
(14)	Variable Revenue	$6,762,020	$11,239,725	$14,736,908	$15,994,938	$12,313,266	$9,945,692	$4,350,574	$2,700,592	$2,154,590	$2,042,541	$2,163,598	$2,951,676	$87,356,120
(15)	Total Variable Revenue	$6,762,020	$11,239,725	$14,736,908	$15,994,938	$12,313,266	$9,945,692	$4,350,574	$2,700,592	$2,154,590	$2,042,541	$2,163,598	$2,951,676	$87,356,120
(16)	III COVID Deferral Revenue													
(17)	(a) Low Load dth	2,076,841	3,475,596	4,567,729	4,963,697	3,812,545	3,073,666	1,327,512	811,489	643,701	609,299	646,808	890,093	26,898,975
(18)	COVID Deferal Factor	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	$0 1770	
(19)	Low Load Revenue	$367,601	$615,180	$808,488	$878,574	$674,820	$544,039	$234,970	$143,634	$113,935	$107,846	$114,485	$157,546	$4,761,118
(20)	(b) High Load dth	56,086	69,723	80,698	81,548	71,399	63,479	44,779	40,352	35,916	34,975	35,650	40,947	655,553
(21)	COVID Deferal Factor	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	$0 1535	
(22)	High Load Revenue	$8,609	$10,703	$12,387	$12,518	$10,960	$9,744	$6,874	$6,194	$5,513	$5,369	$5,472	$6,285	$100,628
(23)	Total COVID Deferral Revenue	$376,210	$625,883	$820,875	$891,092	$685,780	$553,783	$241,844	$149,828	$119,448	$113,215	$119,957	$163,831	$4,861,746
(24)	Total Gas Cost Revenue	$13,435,374	$22,190,925	$29,028,951	$31,491,116	$24,291,295	$19,662,359	$8,723,114	$5,496,343	$4,430,807	$4,212,165	$4,448,642	$5,987,431	$173,398,518

(2) RMS-1, pg 12, Sum [Lines (2)-(5), (7)]
(3) RMS-1, pg 1, Line 1, col (e)
(4) Line (2) x Line (3)
(5) RMS-1, pg 12, Sum [Lines (1), (6), (8)]
(6) RMS-1, pg 1, Line 1, col (d)
(7) Line (5) x Line (6)
(8) Line (2) + Line (5)
(9) [RMS-5, pg 2, Line (25)] ÷ 12
(14) Line (12) x Line (13)
(15) Line (14)
(17) RMS-1, pg 12, Sum [Lines (2)-(5), (7)]
(10) Sum[Lines (4), (7), (9)]
(12) Line (8)
(13) RMS-1, pg 1, Line (2)
(18) RMS-7, pg 1, Line 2, col (d)
(19) Line (17) x Line (18)
(20) RMS-1, pg 12, Sum [Lines (1), (6), (8)]
(21) RMS-7, pg 1, Line 1, col (d)
(22) Line (20) x Line (21)
(23) Line (19) + Line (22)
(24) Line (10) + Line (15)

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Working Capital Estimate

Description (a)	Nov-21 (b)	Dec-21 (c)	Jan-22 (d)	Feb-22 (e)	Mar-22 (f)	Apr-22 (g)	May-22 (h)	Jun-22 (i)	Jul-22 (j)	Aug-22 (k)	Sep-22 (l)	Oct-22 (m)	Total (n)
(1) Fixed Costs	$5,896,129	$9,741,455	$9,737,455	$10,285,725	$10,285,725	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$90,887,120
(2) Capacity Release Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(3) Less System Pressure to DAC	($20,909)	($1,629,488)	($1,629,488)	($1,629,488)	($1,629,488)	($20,909)	($20,909)	($20,909)	($20,909)	($20,909)	($20,909)	($20,909)	($6,685,226)
(4) Less: Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6) Allowable Working Capital Costs	$5,875,220	$8,111,966	$8,107,966	$8,656,236	$8,656,236	$6,399,181	$6,399,181	$6,399,181	$6,399,181	$6,399,181	$6,399,181	$6,399,181	$84,201,894
(7) Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(8) Working Capital Requirement	$529,897	$731,633	$731,272	$780,721	$780,721	$577,154	$577,154	$577,154	$577,154	$577,154	$577,154	$577,154	
(9) Weighted Average Cost of Capital	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	
(10) Return on Working Capital Requirement	$36,616	$50,556	$50,531	$53,948	$53,948	$39,881	$39,881	$39,881	$39,881	$39,881	$39,881	$39,881	
(11) Cost of Debt (Long Term Debt + Short Term Debt)	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	
(12) Interest Expense	$11,552	$15,950	$15,942	$17,020	$17,020	$12,582	$12,582	$12,582	$12,582	$12,582	$12,582	$12,582	
(13) Taxable Income	$25,064	$34,606	$34,589	$36,928	$36,928	$27,299	$27,299	$27,299	$27,299	$27,299	$27,299	$27,299	
(14) 1 - Combined Tax Rate	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(15) Return and Tax Requirement	$31,727	$43,805	$43,784	$46,744	$46,744	$34,556	$34,556	$34,556	$34,556	$34,556	$34,556	$34,556	
(16) Fixed Working Capital Requirement	$43,278	$59,755	$59,725	$63,764	$63,764	$47,138	$47,138	$47,138	$47,138	$47,138	$47,138	$47,138	$620,254
(17) Variable Costs	$7,337,085	$12,624,035	$17,201,504	$14,953,292	$11,758,848	$5,244,070	$1,949,045	$1,216,273	$1,037,896	$1,140,875	$1,142,249	$3,007,443	$78,612,614
(18) Less: Non-firm Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19) Less: Supply Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20) Less: Bal Related Syst Pressure Commodity to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22) Allowable Working Capital Costs	$7,337,085	$12,624,035	$17,201,504	$14,953,292	$11,758,848	$5,244,070	$1,949,045	$1,216,273	$1,037,896	$1,140,875	$1,142,249	$3,007,443	$78,612,614
(23) Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(24) Working Capital Requirement	$661,745	$1,138,584	$1,551,434	$1,348,664	$1,060,551	$472,972	$175,788	$109,698	$93,610	$102,898	$103,022	$271,247	
(25) Weighted Average Cost of Capital	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	
(26) Return on Working Capital Requirement	$45,727	$78,676	$107,204	$93,193	$73,284	$32,682	$12,147	$7,580	$6,468	$7,110	$7,119	$18,743	
(27) Cost of Debt (Long Term Debt + Short Term Debt)	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	
(28) Interest Expense	$14,426	$24,821	$33,821	$29,401	$23,120	$10,311	$3,832	$2,391	$2,041	$2,243	$2,246	$5,913	
(29) Taxable Income	$31,301	$53,855	$73,383	$63,792	$50,164	$22,372	$8,315	$5,189	$4,428	$4,867	$4,873	$12,830	
(30) 1 - Combined Tax Rate	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(31) Return and Tax Requirement	$39,621	$68,171	$92,890	$80,749	$63,499	$28,318	$10,525	$6,568	$5,605	$6,161	$6,168	$16,240	
(32) Variable Working Capital Requirement	$54,047	$92,992	$126,711	$110,150	$86,619	$38,629	$14,357	$8,959	$7,645	$8,404	$8,414	$22,154	$579,082

(1) RMS-1, Pg 2, Line (1)
(3) GSP-1
(6) Sum[Lines (1)-(5)]
(7) Dkt 4770
(8) [Line (6) x Line (7)] ÷ 365
(9) Dkt 5165
(10 Line (8) x Line (9)
(11) Dkt 5165
(12) Line (8) x Line (11)
(13) Line (10) - Line (12)
(14) Tax Law effective Jan 1, 2018
(15) Line (13) ÷ Line (14)
(16) Line (12) + Line (15)
(17) RMS-1, Pg 3, Line (1)
(20) RMS-1, Pg 3, Line (2) ÷ 12
(22) Sum[Lines (17):(21)]
(23) Dkt 4770
(24) [Line (22) x Line (23)] ÷ 365
(25) Dkt 5165
(26) Line (24) x Line (25)
(27) Dkt 4955
(28) Line (24) x Line (27)
(29) Line (26) - Line (28)
(30) Tax Law effective Jan 1, 2018
(31) Line (29) ÷ Line (30)
(32) Line (28) + Line (31)

REDACTED

Storage Fixed Cost Working Capital Calculation for FT-2 Demand Rate (see RMS-5, pg 2)

Description (a)	Nov-21 (b)	Dec-21 (c)	Jan-22 (d)	Feb-22 (e)	Mar-22 (f)	Apr-22 (g)	May-22 (h)	Jun-22 (i)	Jul-22 (j)	Aug-22 (k)	Sep-22 (l)	Oct-22 (m)	Total (n)
(33) Storage Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(34) Less: System Pressure to DAC													
(35) Less: Credits													
(36) Plus: Supply Related LNG O&M Costs													
(37) Allowable Working Capital Costs													
(38) Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(39) Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(40) Weighted Average Cost of Capital	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	
(41) Return on Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(42) Cost of Debt (Long Term Debt + Short Term Debt)	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	
(43) Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(44) Taxable Income	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(45) 1 - Combined Tax Rate	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(46) Return and Tax Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(47) Storage Fixed Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$169,227

(33) RMS-1, pg 5, Line (40)
(34) Line (3)
(37) Sum[Lines (33) - (36)]
(38) Dkt 4770
(39) [Line (37) x Line (38)] ÷ 365
(40) Dkt 5165
(41) Line (39) x Line (40)
(42) Dkt 5165
(43) Line (39) x Line (42)
(44) Line (41) - Line (43)
(45) Tax Law effective Jan 1, 2018
(46) Line (44) ÷ Line (45)
(47) Line (43) + Line (46)

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Inventory Finance Estimate

Description (a)	Source (b)	Nov-21 (c)	Dec-21 (d)	Jan-22 (e)	Feb-22 (f)	Mar-22 (g)	Apr-22 (h)	May-22 (i)	Jun-22 (j)	Jul-22 (k)	Aug-22 (l)	Sep-22 (m)	Oct-22 (n)	Total (o)
(1) **Storage Inventory Balance**	GSP-1	$9,572,864	$7,304,261	$4,861,492	$2,617,341	$1,135,121	$1,197,526	$3,182,649	$4,146,261	$5,911,109	$7,927,310	$9,613,997	$11,296,878	
(2) Hedging		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(3) Subtotal	(1) + (2)	$9,572,864	$7,304,261	$4,861,492	$2,617,341	$1,135,121	$1,197,526	$3,182,649	$4,146,261	$5,911,109	$7,927,310	$9,613,997	$11,296,878	
(4) Weighted Average Cost of Capital	Dkt 5165	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	
(5) Return on Working Capital Requirement	(3) x (4)	$661,485	$504,724	$335,929	$180,858	$78,437	$82,749	$219,921	$286,507	$408,458	$547,777	$664,327	$780,614	$4,751,787
(6) Cost of Debt (LTD + STD)*	Dkt 5165	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	
(7) Interest Charges Financed	(3) x (6)	$208,688	$159,233	$105,981	$57,058	$24,746	$26,106	$69,382	$90,388	$128,862	$172,815	$209,585	$246,272	$1,499,116
(8) Taxable Income	(5) - (7)	$452,796	$345,492	$229,949	$123,800	$53,691	$56,643	$150,539	$196,118	$279,595	$374,962	$454,742	$534,342	
(9) 1 - Combined Tax Rate		0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(10) Return and Tax Requirement	(8) ÷ (9)	$573,160	$437,331	$291,074	$156,709	$67,964	$71,700	$190,556	$248,251	$353,918	$474,635	$575,623	$676,383	$4,117,304
(11) Working Capital Requirement	(7) + (10)	$781,849	$596,564	$397,055	$213,767	$92,709	$97,806	$259,938	$338,639	$482,780	$647,450	$785,208	$922,655	$5,616,420
(12) Storage-Related Inventory Costs	(11) ÷ 12	$65,154	$49,714	$33,088	$17,814	$7,726	$8,151	$21,661	$28,220	$40,232	$53,954	$65,434	$76,888	$468,035
(13) **LNG Inventory Balance**	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(14) Weighted Average Cost of Capital	Dkt 5165	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	6 91%	
(15) Return on Working Capital Requirement	(13) x (14)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,719,680
(16) Cost of Debt (LTD + STD)*	Dkt 5165	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	2 18%	
(17) Interest Charges Financed	(13) x (16)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$858,018
(18) Taxable Income	(15) - (17)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(19) 1 - Combined Tax Rate		0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(20) Return and Tax Requirement	(18) ÷ (19)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,356,534
(21) Working Capital Requirement	(17) + (20)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$3,214,552
(22) LNG-Related Inventory Costs	(21) ÷ 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$267,879
(23) Total Inventory Financing Costs	(12) + (22)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$735,914

*LTD: Long Term Debt
*STD: Short Term Debt

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Forecasted Throughput (Dth)

	Rate Class	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	SALES													
(1)	Residential Non-Heating	26,077	37,414	47,084	50,236	40,433	33,894	17,716	12,854	8,013	6,392	7,967	12,706	300,785
(2)	Residential Heating	1,528,915	2,589,854	3,439,229	3,811,850	2,887,874	2,339,944	955,323	597,144	477,322	453,942	477,646	644,498	20,203,541
(3)	Small C&I	184,206	298,399	380,743	388,554	311,395	246,807	124,451	70,922	54,679	50,946	55,621	81,581	2,248,302
(4)	Medium C&I	299,010	482,518	614,005	626,797	503,885	400,214	204,019	118,508	92,492	86,514	94,001	135,356	3,657,319
(5)	Large LLF	56,685	91,826	117,165	119,569	95,825	75,950	38,297	21,825	16,826	15,678	17,116	25,105	691,867
(6)	Large HLF	20,518	22,091	22,983	21,409	21,173	20,228	18,504	18,801	19,078	19,543	18,928	19,309	242,567
(7)	Extra Large LLF	8,025	13,000	16,587	16,927	13,566	10,752	5,422	3,090	2,382	2,219	2,423	3,554	97,947
(8)	Extra Large HLF	9,491	10,218	10,631	9,903	9,794	9,357	8,559	8,697	8,825	9,040	8,756	8,931	112,201
(9)	**Total Sales**	2,132,927	3,545,319	4,648,427	5,045,244	3,883,944	3,137,145	1,372,291	851,841	679,617	644,274	682,458	931,040	27,554,528
	TRANSPORTATION													
(10)	FT- Small	14,152	22,925	29,251	29,851	23,923	18,961	9,561	5,449	4,201	3,914	4,273	6,268	172,729
(11)	FT- Medium	219,044	354,834	452,751	462,040	370,288	293,485	147,988	84,336	65,020	60,581	66,140	97,010	2,673,516
(12)	FT- Large LLF	171,796	278,296	355,093	362,378	290,417	230,180	116,067	66,144	50,995	47,514	51,874	76,085	2,096,839
(13)	FT- Large HLF	75,991	81,884	84,666	78,948	78,653	75,148	71,421	72,765	73,741	75,376	73,213	74,253	916,058
(14)	FT- Extra Large LLF	71,514	115,847	147,815	150,847	120,892	95,817	48,315	27,534	21,228	19,779	21,594	31,672	872,853
(15)	FT- Extra Large HLF	506,416	545,221	567,237	528,399	522,566	499,250	456,705	464,036	470,874	482,339	467,172	476,560	5,986,775
(16)	**Total FT Transportation**	1,058,913	1,399,007	1,636,814	1,612,463	1,406,739	1,212,842	850,056	720,264	686,058	689,503	684,266	761,846	12,718,770
	Total THROUGHPUT													
(17)	Residential Non-Heating	26,077	37,414	47,084	50,236	40,433	33,894	17,716	12,854	8,013	6,392	7,967	12,706	300,785
(18)	Residential Heating	1,528,915	2,589,854	3,439,229	3,811,850	2,887,874	2,339,944	955,323	597,144	477,322	453,942	477,646	644,498	20,203,541
(19)	Small C&I	198,358	321,323	409,994	418,405	335,318	265,768	134,012	76,371	58,880	54,860	59,894	87,848	2,421,031
(20)	Medium C&I	518,054	837,351	1,066,756	1,088,836	874,173	693,699	352,007	202,844	157,512	147,095	160,142	232,366	6,330,834
(21)	Large LLF	228,481	370,122	472,258	481,947	386,242	306,130	154,364	87,969	67,821	63,192	68,990	101,189	2,788,706
(22)	Large HLF	96,510	103,975	107,649	100,357	99,826	95,376	89,925	91,567	92,819	94,919	92,141	93,561	1,158,625
(23)	Extra Large LLF	79,539	128,846	164,402	167,775	134,458	106,569	53,737	30,624	23,610	21,998	24,017	35,226	970,800
(24)	Extra Large HLF	515,907	555,440	577,868	538,302	532,360	508,607	465,264	472,732	479,699	491,379	475,928	485,491	6,098,976
(25)	**Total Throughput**	3,191,840	4,944,326	6,285,240	6,657,707	5,290,682	4,349,987	2,222,347	1,572,105	1,365,675	1,333,777	1,366,725	1,692,886	40,273,298

Source: Attachement TEP-1

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Design Winter Period and Design Day Throughput (Dth)

	Rate Class (a)	Reference	Line #	Nov-21 (b)	Dec-21 (c)	Jan-22 (d)	Feb-22 (e)	Mar-22 (f)	Total (g)	% (h)
	SALES (dth)									
(1)	Residential Non-Heating	RMS-1, pg 16	Line (70)	28,570	42,249	53,539	57,300	45,278	226,935	1.04%
(2)	Residential Heating	RMS-1, pg 16	Line (71)	1,670,861	2,932,169	3,923,047	4,362,159	3,243,341	16,131,578	74.14%
(3)	Small C&I	RMS-1, pg 16	Line (72)	201,675	337,899	434,014	443,776	349,262	1,766,626	8.12%
(4)	Medium C&I	RMS-1, pg 16	Line (74)	326,880	545,721	699,200	715,240	564,559	2,851,600	13.11%
(5)	Large LLF	RMS-1, pg 16	Line (76)	62,061	103,981	133,559	136,562	107,478	543,641	2.50%
(6)	Large HLF	RMS-1, pg 16	Line (78)	20,751	22,528	23,569	22,043	21,435	110,325	0.51%
(7)	Extra Large LLF	RMS-1, pg 16	Line (80)	8,786	14,721	18,908	19,333	15,216	76,963	0.35%
(8)	Extra Large HLF	RMS-1, pg 16	Line (82)	9,599	10,420	10,902	10,196	9,915	51,032	0.23%
(9)	Total Sales	Sum[(1):(8)]		2,329,183	4,009,687	5,296,737	5,766,609	4,356,483	21,758,699	100.00%
(10)	Low Load Factor	Sum[(2)-(5),(7)]		2,270,264	3,934,490	5,208,728	5,677,070	4,279,855	21,370,407	98.22%
(11)	High Load Factor	Sum[(1),(6),(8)]		58,919	75,197	88,009	89,538	76,628	388,292	1.78%

REDACTED

2021/2022 Design Day Send Out

(12)	Pipeline	212,782	Dktherm
(13)	Underground Storage	42,761	Dktherm
(14)	LNG	[redacted]	Dktherm
(15)	Total Projected 2021/2022 Design Day	[redacted]	Dktherm

(1) Column (h): [Line (1), Col (g)]÷[Line (9), Col (g)]
(2) Column (h): [Line (2), Col (g)]÷[Line (9), Col (g)]
(3) Column (h): [Line (3), Col (g)]÷[Line (9), Col (g)]
(4) Column (h): [Line (4), Col (g)]÷[Line (9), Col (g)]
(5) Column (h): [Line (5), Col (g)]÷[Line (9), Col (g)]
(6) Column (h): [Line (6), Col (g)]÷[Line (9), Col (g)]
(7) Column (h): [Line (7), Col (g)]÷[Line (9), Col (g)]
(8) Column (h): [Line (8), Col (g)]÷[Line (9), Col (g)]
(10) Column (h): [Line (10), Col (g)]÷[Line (9), Col (g)]
(11) Column (h): [Line (11), Col (g)]÷[Line (9), Col (g)]

REDACTED

Derivation of Monthly Design Sales

Normal Volumes (Dth)

	(a)	Nov-21 (b)	Dec-21 (c)	Jan-22 (d)	Feb-22 (e)	Mar-22 (f)	Apr-22 (g)	May-22 (h)	Jun-22 (i)	Jul-22 (j)	Aug-22 (k)	Sep-22 (l)	Oct-22 (m)	Nov-Oct (n)
(1)	Residential Non-Heating	26,077	37,414	47,084	50,236	40,433	33,894	17,716	12,854	8,013	6,392	7,967	12,706	300,785
(2)	Residential Heating	1,528,915	2,589,854	3,439,229	3,811,850	2,887,874	2,339,944	955,323	597,144	477,322	453,942	477,646	644,498	20,203,541
(3)	Small C&I	184,206	298,399	380,743	388,554	311,395	246,807	124,451	70,922	54,679	50,946	55,621	81,581	2,248,302
(4)	Small Transport	14,152	22,925	29,251	29,851	23,923	18,961	9,561	5,449	4,201	3,914	4,273	6,268	172,729
(5)	Medium C&I	299,010	482,518	614,005	626,797	503,885	400,214	204,019	118,508	92,492	86,514	94,001	135,356	3,657,319
(6)	Med Transport	219,044	354,834	452,751	462,040	370,288	293,485	147,988	84,336	65,020	60,581	66,140	97,010	2,673,516
(7)	Large Low Load	56,685	91,826	117,165	119,569	95,825	75,950	38,297	21,825	16,826	15,678	17,116	25,105	691,867
(8)	Large Low Load- Transport	171,796	278,296	355,093	362,378	290,417	230,180	116,067	66,144	50,995	47,514	51,874	76,085	2,096,839
(9)	Large High Load	20,518	22,091	22,983	21,409	21,173	20,228	18,504	18,801	19,078	19,543	18,928	19,309	242,567
(10)	Large High Load- Transport	75,991	81,884	84,666	78,948	78,653	75,148	71,421	72,765	73,741	75,376	73,213	74,253	916,058
(11)	XL Low Load	8,025	13,000	16,587	16,927	13,566	10,752	5,422	3,090	2,382	2,219	2,423	3,554	97,947
(12)	XL Low Load-Transport	71,514	115,847	147,815	150,847	120,892	95,817	48,315	27,534	21,228	19,779	21,594	31,672	872,853
(13)	XL High Load	9,491	10,218	10,631	9,903	9,794	9,357	8,559	8,697	8,825	9,040	8,756	8,931	112,201
(14)	XL High Load-Transport	506,416	545,221	567,237	528,399	522,566	499,250	456,705	464,036	470,874	482,339	467,172	476,560	5,986,775
(15)	**Total**	3,191,840	4,944,326	6,285,240	6,657,707	5,290,682	4,349,987	2,222,347	1,572,105	1,365,675	1,333,777	1,366,725	1,692,886	40,273,298
(16)	HLF	638,493	696,829	732,602	688,894	672,618	637,877	572,905	577,153	580,531	592,690	576,036	591,759	7,558,386
(17)	LLF	2,553,347	4,247,497	5,552,639	5,968,813	4,618,065	3,712,110	1,649,443	994,952	785,145	741,087	790,689	1,101,127	32,714,912

Baseload

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-Oct
		30	31	31	28	31	30	31	30	31	31	30	31	
(18)	Residential Non-Heating	7,295	7,538	7,538	6,809	7,538	7,295	7,538	7,295	7,538	6,392	7,295	7,538	87,612
(19)	Residential Heating	459,427	474,741	474,741	428,799	474,741	459,427	474,741	459,427	474,741	453,942	459,427	474,741	5,568,898
(20)	Small C&I	52,580	54,333	54,333	49,075	54,333	52,580	54,333	52,580	54,333	50,946	52,580	54,333	636,339
(21)	Small Transport	4,040	4,174	4,174	3,770	4,174	4,040	4,174	4,040	4,174	3,914	4,040	4,174	48,888
(22)	Medium C&I	89,024	91,991	91,991	83,089	91,991	89,024	91,991	89,024	91,991	86,514	89,024	91,991	1,077,646
(23)	Med Transport	62,524	64,609	64,609	58,356	64,609	62,524	64,609	62,524	64,609	60,581	62,524	64,609	756,687
(24)	Large Low Load	16,180	16,720	16,720	15,102	16,720	16,180	16,720	16,180	16,720	15,678	16,180	16,720	195,820
(25)	Large Low Load- Transport	49,038	50,673	50,673	45,769	50,673	49,038	50,673	49,038	50,673	47,514	49,038	50,673	593,470
(26)	Large High Load	18,766	19,392	19,392	17,515	19,392	18,766	18,504	18,766	19,078	19,392	18,766	19,309	227,039
(27)	Large High Load- Transport	72,499	74,915	74,915	67,666	74,915	72,499	71,421	72,499	73,741	74,915	72,499	74,253	876,737
(28)	XL Low Load	2,291	2,367	2,367	2,138	2,367	2,291	2,367	2,291	2,367	2,219	2,291	2,367	27,722
(29)	XL Low Load-Transport	20,413	21,094	21,094	19,052	21,094	20,413	21,094	20,413	21,094	19,779	20,413	21,094	247,044
(30)	XL High Load	8,681	8,970	8,970	8,102	8,970	8,681	8,559	8,681	8,825	8,970	8,681	8,931	105,019
(31)	XL High Load-Transport	463,169	478,608	478,608	432,291	478,608	463,169	456,705	463,169	470,874	478,608	463,169	476,560	5,603,537
(32)	Total	1,325,927	1,370,125	1,370,125	1,237,532	1,370,125	1,325,927	1,343,429	1,325,927	1,360,758	1,329,364	1,325,927	1,367,292	16,052,458
(33)	HLF	570,410	589,423	589,423	532,382	589,423	570,410	562,727	570,410	580,056	588,278	570,410	586,591	6,899,944
(34)	LLF	755,517	780,701	780,701	705,150	780,701	755,517	780,701	755,517	780,701	741,087	755,517	780,701	9,152,514

REDACTED

Derivation of Monthly Design Sales

Heat Volumes

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(35) Residential Non-Heating	18,782	29,876	39,546	43,427	32,894	26,599	10,177	5,558	475	0	671	5,168	213,173
(36) Residential Heating	1,069,488	2,115,113	2,964,487	3,383,051	2,413,132	1,880,516	480,581	137,717	2,580	0	18,219	169,756	14,634,642
(37) Small C&I	131,626	244,066	326,410	339,479	257,062	194,227	70,118	18,342	346	0	3,041	27,248	1,611,964
(38) Small Transport	10,112	18,751	25,077	26,081	19,749	14,922	5,387	1,409	27	0	234	2,093	123,841
(39) Medium C&I	209,986	390,526	522,014	543,708	411,894	311,190	112,028	29,484	501	0	4,977	43,365	2,579,672
(40) Med Transport	156,519	290,225	388,143	403,684	305,679	230,960	83,379	21,811	411	0	3,616	32,401	1,916,829
(41) Large Low Load	40,505	75,106	100,446	104,467	79,105	59,769	21,577	5,644	106	0	936	8,385	496,047
(42) Large Low Load- Transport	122,758	227,624	304,420	316,609	239,744	181,142	65,394	17,106	323	0	2,836	25,412	1,503,369
(43) Large High Load	1,752	2,699	3,591	3,894	1,781	1,462	0	35	0	151	162	0	15,528
(44) Large High Load- Transport	3,492	6,969	9,751	11,282	3,737	2,649	0	267	0	461	714	0	39,322
(45) XL Low Load	5,734	10,633	14,220	14,789	11,199	8,461	3,055	799	15	0	132	1,187	70,225
(46) XL Low Load-Transport	51,101	94,753	126,721	131,795	99,799	75,404	27,222	7,121	134	0	1,181	10,578	625,809
(47) XL High Load	811	1,248	1,661	1,801	824	676	0	16	0	70	75	0	7,182
(48) XL High Load-Transport	43,247	66,613	88,629	96,108	43,958	36,081	0	867	0	3,731	4,003	0	383,237
(49) Total	1,865,913	3,574,201	4,915,116	5,420,175	3,920,558	3,024,060	878,919	246,177	4,918	4,413	40,797	325,594	24,220,840
(50) HLF	68,083	107,405	143,178	156,512	83,194	67,468	10,177	6,743	475	4,413	5,626	5,168	658,442
(51) LLF	1,797,829	3,466,796	4,771,937	5,263,663	3,837,363	2,956,592	868,741	239,435	4,443	0	35,172	320,426	23,562,398
(52) **Normal Billing DD**	**437**	**760**	**1011**	**1125**	**835**	**673**	**262**	**131**	**19**	**0**	**13**	**156**	**5422**

Heat Factors

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(53) Residential Non-Heating	43	39	39	39	39	40	39	42	25	0	52	33	39
(54) Residential Heating	2,447	2,783	2,932	3,007	2,890	2,794	1,834	1,051	136	0	1,401	1,088	2,699
(55) Small C&I	301	321	323	302	308	289	268	140	18	0	234	175	297
(56) Small Transport	23	25	25	23	24	22	21	11	1	0	18	13	23
(57) Medium C&I	481	514	516	483	493	462	428	225	26	0	383	278	476
(58) Med Transport	358	382	384	359	366	343	318	166	22	0	278	208	354
(59) Large Low Load	93	99	99	93	95	89	82	43	6	0	72	54	91
(60) Large Low Load- Transport	281	300	301	281	287	269	250	131	17	0	218	163	277
(61) Large High Load	4	4	4	3	2	2	0	0	0	0	12	0	3
(62) Large High Load- Transport	8	9	10	10	4	4	0	2	0	0	55	0	7
(63) XL Low Load	13	14	14	13	13	13	12	6	1	0	10	8	13
(64) XL Low Load-Transport	117	125	125	117	120	112	104	54	7	0	91	68	115
(65) XL High Load	2	2	2	2	1	1	0	0	0	0	6	0	1
(66) XL High Load-Transport	99	88	88	85	53	54	0	7	0	0	308	0	71
(67) Total	4,270	4,703	4,862	4,818	4,695	4,493	3,355	1,879	259	0	3,138	2,087	4,467
(68) **NormalBilling DD**	**437**	**760**	**1011**	**1125**	**835**	**673**	**262**	**131**	**19**	**0**	**13**	**156**	**5422**
(69) **DesignBilling DD**	**495**	**883**	**1176**	**1308**	**958**	**771**	**292**	**154**	**27**	**0**	**9**	**177**	**6250**

REDACTED

Derivation of Monthly Design Sales

Design Sales

	(a)	Nov-21 (b)	Dec-21 (c)	Jan-22 (d)	Feb-22 (e)	Mar-22 (f)	Apr-22 (g)	May-22 (h)	Jun-22 (i)	Jul-22 (j)	Aug-22 (k)	Sep-22 (l)	Oct-22 (m)	Nov-Oct
(70)	Residential Non-Heating	28,570	42,249	53,539	57,300	45,278	37,767	18,881	13,830	7,538	6,392	7,760	13,402	332,505
(71)	Residential Heating	1,670,861	2,932,169	3,923,047	4,362,159	3,243,341	2,613,778	1,010,351	621,324	474,741	453,942	472,040	667,350	22,445,104
(72)	Small C&I	201,675	337,899	434,014	443,776	349,262	275,090	132,480	74,143	54,333	50,946	54,685	85,249	2,493,551
(73)	Small Transport	15,494	25,960	33,344	34,094	26,833	21,134	10,178	5,696	4,174	3,914	4,201	6,549	191,571
(74)	Medium C&I	326,880	545,721	699,200	715,240	564,559	445,529	216,847	123,685	91,991	86,514	92,470	141,194	4,049,829
(75)	Med Transport	239,818	401,804	516,098	527,706	415,316	327,116	157,535	88,165	64,609	60,581	65,028	101,371	2,965,147
(76)	Large Low Load	62,061	103,981	133,559	136,562	107,478	84,653	40,768	22,816	16,720	15,678	16,828	26,233	767,337
(77)	Large Low Load- Transport	188,089	315,135	404,776	413,880	325,732	256,557	123,555	69,148	50,673	47,514	51,001	79,506	2,325,565
(78)	Large High Load	20,751	22,528	23,569	22,043	21,435	20,441	18,504	18,808	19,078	19,392	18,879	19,309	244,736
(79)	Large High Load- Transport	76,455	83,012	86,258	80,783	79,203	75,534	71,421	72,812	73,741	74,915	72,993	74,253	921,379
(80)	XL Low Load	8,786	14,721	18,908	19,333	15,216	11,984	5,771	3,230	2,367	2,219	2,382	3,714	108,631
(81)	XL Low Load-Transport	78,296	131,182	168,496	172,286	135,593	106,797	51,432	28,784	21,094	19,779	21,230	33,096	968,065
(82)	XL High Load	9,599	10,420	10,902	10,196	9,915	9,455	8,559	8,700	8,825	8,970	8,732	8,931	113,205
(83)	XL High Load-Transport	512,156	556,002	581,702	544,033	529,041	504,504	456,705	464,188	470,874	478,608	465,941	476,560	6,040,313
(84)	Total	3,439,490	5,522,782	7,087,411	7,539,389	5,868,202	4,790,341	2,322,987	1,615,327	1,360,758	1,329,364	1,354,172	1,736,716	43,966,937
(85)	HLF	647,529	714,211	755,969	714,354	684,873	647,702	574,070	578,337	580,056	588,278	574,305	592,455	7,652,137
(86)	LLF	2,791,960	4,808,571	6,331,442	6,825,035	5,183,329	4,142,639	1,748,917	1,036,990	780,701	741,087	779,867	1,144,261	36,314,800

Source: Attachement TEP-1

Attachment RMS-2
Redacted

Attachment RMS-2
Annual GCR Reconciliation Filing

REDACTED

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

Deferred Gas Cost Balances

	Description	Apr-20 Actual	May-20 Actual	Jun-20 Actual	Jul-20 Actual	Aug-20 Actual	Sep-20 Actual	Oct-20 Actual	Nov-20 Actual	Dec-20 Actual	Jan-21 Actual	Feb-21 Actual	Mar-21 Actual	Apr-Mar
(1)	# of Days in Month	30	31	30	31	31	30	31	30	31	31	28	31	365
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(2)	I Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	($8,461,383)	($9,710,995)	($12,426,527)	($9,488,015)	($6,100,630)	($2,600,025)	$2,150,791	$6,235,963	$7,685,937	$7,128,094	$1,076,203	($5,082,948)	($8,461,383)
(4)	Supply Fixed Costs (net of cap rel)	$5,567,480	$2,777,190	$5,553,300	$5,391,037	$5,387,032	$5,431,471	$6,365,529	$6,172,559	$8,866,638	$8,836,970	$9,180,189	$9,050,245	$78,579,640
(5)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	($20,574)	($1,305,540)	($1,242,058)	($1,252,572)	($1,147,240)	($4,967,984)
(6)	Supply Related LNG O&M	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$115,939	$876,610
(7)	NGPMP Credits	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	$629,846	($475,000)	($437,588)	($437,588)	($1,338,739)	($437,588)	($3,167,524)	($8,039,179)
(8)	Working Capital	$42,116	$21,009	$42,009	$40,782	$40,751	$41,087	$48,153	$46,538	$57,197	$57,453	$59,970	$59,784	$556,850
(9)	Total Supply Fixed Costs	$5,203,748	$2,392,351	$5,189,461	$5,025,971	$5,021,935	$6,171,557	$6,007,834	$5,830,086	$7,249,859	$6,382,779	$7,619,152	$4,911,204	$67,005,935
(10)	Supply Fixed - Revenue	$6,444,030	$5,096,139	$2,239,697	$1,630,316	$1,516,713	$1,420,511	$1,927,112	$4,198,905	$7,815,561	$12,439,023	$13,776,383	$11,455,910	$69,960,298
(11)	Monthly Under/(Over) Recovery	($1,240,282)	($2,703,788)	$2,949,764	$3,395,655	$3,505,222	$4,751,047	$4,080,722	$1,631,181	($565,703)	($6,056,244)	($6,157,231)	($6,544,706)	($2,954,362)
(12)	Prelim Ending Under/(Over) Recovery	($9,701,664)	($12,414,782)	($9,476,763)	($6,092,360)	($2,595,408)	$2,151,022	$6,231,513	$7,867,144	$7,120,235	$1,071,850	($5,081,028)	($11,627,655)	($11,415,745)
(13)	Month's Average Balance	($9,081,523)	($11,062,888)	($10,951,645)	($7,790,187)	($4,348,019)	($224,501)	$4,191,152	$7,051,554	$7,403,086	$4,099,972	($2,002,413)	($8,355,301)	
(14)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(15)	Interest Applied	($9,330)	($11,745)	($11,252)	($8,270)	($4,616)	($231)	$4,450	$7,245	$7,859	$4,353	($1,920)	($8,870)	($32,328)
(16)	Marketer Reconciliation	$0	$0	$0	$0	$0	$0	$0	($188,452)	$0	$0	$0	$0	($188,452)
(17)	Fixed Ending Under/(Over) Recovery	($9,710,995)	($12,426,527)	($9,488,015)	($6,100,630)	($2,600,025)	$2,150,791	$6,235,963	$7,685,937	$7,128,094	$1,076,203	($5,082,948)	($11,636,525)	($11,636,525)
(18)	II Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$9,288,955	$7,486,618	$4,141,027	$3,753,168	$3,975,835	$4,327,618	$4,746,721	$5,896,957	$7,145,258	$11,196,560	$13,753,077	$16,711,897	$9,288,955
(20)	Variable Supply Costs	$6,292,144	$2,983,048	$2,126,101	$1,913,246	$1,899,688	$1,848,549	$3,227,386	$5,716,480	$11,965,664	$15,388,563	$17,212,370	$9,216,169	$79,789,407
(21)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Supply Related LNG O & M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(23)	Inventory Financing - LNG	$23,875	$23,482	$23,089	$23,331	$23,468	$23,401	$23,408	$23,751	$23,050	$22,804	$22,275	$22,830	$278,763
(24)	Inventory Financing - UG	$52,404	$56,661	$58,782	$62,219	$65,935	$72,790	$76,526	$74,899	$68,025	$58,259	$49,740	$42,819	$739,059
(25)	Working Capital	$47,598	$22,566	$16,083	$14,473	$14,371	$13,984	$24,414	$43,243	$90,517	$116,410	$130,206	$69,717	$603,582
(26)	Total Supply Variable Costs	$6,441,208	$3,110,944	$2,249,242	$2,038,456	$2,028,648	$1,983,911	$3,376,922	$5,883,560	$12,172,442	$15,611,223	$17,439,779	$9,376,722	$81,713,056
(27)	Supply Variable - Revenue	$8,252,159	$6,462,704	$2,641,154	$1,819,890	$1,681,270	$1,569,467	$2,232,332	$4,690,905	$8,130,870	$13,067,943	$14,495,558	$12,009,601	$77,053,853
(28)	Monthly Under/(Over) Recovery	($1,810,951)	($3,351,760)	($391,912)	$218,566	$347,378	$414,444	$1,144,589	$1,192,655	$4,041,571	$2,543,280	$2,944,220	($2,632,879)	$4,659,203
(29)	Prelim Ending Under/(Over) Recovery	$7,478,005	$4,134,858	$3,749,115	$3,971,734	$4,323,212	$4,742,062	$5,891,310	$7,089,612	$11,186,829	$13,739,840	$16,697,297	$14,079,018	$13,948,158
(30)	Month's Average Balance	$8,383,480	$5,810,738	$3,945,071	$3,862,451	$4,149,524	$4,534,840	$5,319,016	$6,493,285	$9,166,043	$12,468,200	$15,225,187	$15,395,457	
(31)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(32)	Interest Applied	$8,613	$6,169	$4,053	$4,101	$4,405	$4,659	$5,647	$6,671	$9,731	$13,237	$14,599	$16,344	$98,230
(33)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$48,974	$0	$0	$0	$0	$48,974
(34)	Variable Ending Under/(Over) Recovery	$7,486,618	$4,141,027	$3,753,168	$3,975,835	$4,327,618	$4,746,721	$5,896,957	$7,145,258	$11,196,560	$13,753,077	$16,711,897	$14,095,362	$14,095,362
(35)	III COVID Deferred													
(36)	Beginning Balance	$0	$0	$0	$0	$0	$0	$0	$0	$154,001	$693,790	$1,563,369	$2,528,850	$0
(37)	COVID Cost Deferral	$0	$0	$0	$0	$0	$0	$0	$153,922	$539,339	$868,382	$963,520	$798,445	$3,323,607
(38)	Prelim Ending Balance	$0	$0	$0	$0	$0	$0	$0	$153,922	$693,340	$1,562,172	$2,526,889	$3,327,295	
(39)	Month's Average Balance	$0	$0	$0	$0	$0	$0	$0	$76,961	$423,671	$1,127,981	$2,045,129	$2,928,072	
(40)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(41)	Interest Applied	$0	$0	$0	$0	$0	$0	$0	$79	$450	$1,198	$1,961	$3,109	$6,796
(42)	Ending Balance	$0	$0	$0	$0	$0	$0	$0	$154,001	$693,790	$1,563,369	$2,528,850	$3,330,403	$3,330,403
(43)	**GCR Deferred Summary**													
(44)	Beginning Under/(Over) Recovery	$827,573	($2,224,377)	($8,285,500)	($5,734,847)	($2,124,796)	$1,727,593	$6,897,512	$12,132,920	$14,985,196	$19,018,444	$16,392,649	$14,157,799	$827,573
(45)	Gas Costs	$11,953,963	$5,854,577	$7,773,739	$7,398,622	$7,381,058	$7,374,359	$9,687,254	$11,774,351	$19,621,100	$23,077,814	$25,234,327	$17,260,300	$154,391,465
(46)	Inventory Finance	$76,279	$80,143	$81,871	$85,550	$89,402	$96,191	$99,934	$98,650	$91,074	$81,063	$72,015	$65,649	$1,017,822
(47)	Working Capital	$89,714	$43,574	$58,092	$55,255	$55,122	$55,071	$72,567	$89,781	$147,714	$173,863	$190,176	$129,501	$1,160,432
(48)	NGPMP Credits	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	$629,846	($475,000)	($437,588)	($437,588)	($1,338,739)	($437,588)	($3,167,524)	($8,039,179)
(49)	Total Costs	$11,644,957	$5,503,295	$7,438,703	$7,064,427	$7,050,583	$8,155,468	$9,384,755	$11,525,194	$19,422,300	$21,994,002	$25,058,930	$14,287,926	$148,530,540
(50)	Revenue	$14,696,189	$11,558,842	$4,880,850	$3,450,206	$3,197,983	$2,989,977	$4,159,444	$8,735,887	$15,407,093	$24,638,584	$27,308,421	$22,667,067	$143,690,544
(51)	Monthly Under/(Over) Recovery	($3,051,233)	($6,055,548)	$2,557,852	$3,614,221	$3,852,600	$5,165,491	$5,225,311	$2,789,307	$4,015,207	($2,644,582)	($2,249,491)	($8,379,141)	$4,839,996
(52)	Prelim Ending Under/(Over) Recovery	($2,223,660)	($8,279,925)	($5,727,648)	($2,120,626)	$1,727,804	$6,893,084	$12,122,824	$14,922,227	$19,000,403	$16,373,862	$14,143,158	$5,778,658	
(53)	Month's Average Balance	($698,043)	($5,252,151)	($7,006,574)	($3,927,736)	($198,496)	$4,310,339	$9,510,168	$13,527,574	$16,992,800	$17,696,153	$15,267,904	$9,968,228	
(54)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(55)	Interest Applied	($717)	($5,576)	($7,199)	($4,170)	($211)	$4,428	$10,096	$13,995	$18,040	$18,787	$14,640	$10,583	$72,698
(56)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$48,974	$0	$0	$0	$0	$48,974
(57)	**Ending Under/(Over) Recovery W/ Interest**	($2,224,377)	($8,285,500)	($5,734,847)	($2,124,796)	$1,727,593	$6,897,512	$12,132,920	$14,985,196	$19,018,444	$16,392,649	$14,157,799	$\boxed{\$5,789,241}$	$5,789,241

(3) Dkt 5066, Sch RMS/MJP-2, pg 1, line (17), col (m)
(4) Sch 2, line (44)
(5) Dkt 4955; Dkt 5040
(6) Docket 4770
(8) Sch 4, line (15)
(9) Sum[Lines (4) : (8)]
(10) Sch 3, line (10)
(11) Line (9) - Line (10)
(12) Line (3) + Line (11)
(13) [Line (3) + Line (12)] ÷ 2
(15) ([Line (13) x Line (14)] ÷ 365) x Line (1)
(16) Dkt 5066
(17) Line (12) + Line (15) + Line (16)
(19) Dkt 5066, Sch RMS/MJP-2, pg 1, line (34), col (m)
(20) Sch 2, line (100)
(21) Dkt 4955; Dkt 5040
(22) Docket 4770
(23) Sch 5, line (22)
(24) Sch 5, line (12)
(25) Sch 4, line (30)
(26) Sum[Lines (20) : (25)]
(27) Sch 3, line (24)
(28) Line (26) - Line (27)
(29) Line (19) + Line (28)
(30) [Line (19) + Line (29)] ÷ 2
(32) ([Line (30) x Line (31)] ÷ 365) x Line (1)
(34) Line (29) + Line (32) + Line (33)
(37) Sch 6, Line (38)
(38) Line (36) + Line (37)
(39) [[Line (36) + Line (38)] ÷ 2
(41) ([Line (39) x Line (40)] / 365) x Line (1)
(42) Line (38) + Line (41)
(44) Line (3) + Line (19) + Line (36)
(45) Sum[Lines (4) (6), (16), (20) (22)]
(46) Line (23) + Line (24)
(47) Line (8) + Line (25)
(48) Line (7)
(49) Sum[Lines (45) : (48)]
(50) Line (10) + Line (27) + Line (37)
(51) Line (49) - Line (50)
(52) Line (44) + Line (51)
(53) [[Line (44) + Line (52)] ÷ 2
(55) Line (15) + Line (32) + Line (41)
(56) Line (33)
(57) Line (52) + Line (55) + Line (56)

REDACTED

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

Supply Estimates Actuals for Filing

	Description	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(1)	**SUPPLY FIXED COSTS - Pipeline Delivery**													
(2)	Algonquin*	$0	$0	$0	$0	$0	$0	$648,797	$0	$0	$0	$0	$0	$648,797
(3)	Dawn to E Here	$1,094,343	$1,110,633	$1,106,174	$1,124,707	$1,126,476	$1,119,050	$1,134,257	$1,025,492	$1,125,751	$1,157,911	$1,272,430	$1,245,385	$13,642,609
(4)	Dawn to WADDY	$11,711	$11,711	$11,711	$11,711	$11,711	$11,711	$11,711	$21,074	$21,200	$21,429	$25,277	$23,604	$194,560
(5)	Dominion SP	$6,763	$6,763	$6,763	$5,231	$6,626	$7,037	$7,037	$7,040	$7,021	$7,021	$7,021	$7,021	$81,342
(6)	Dracut	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$83,636	$83,636	$83,636	$83,636	$83,636	$1,013,348
(7)	Everett	$104,580	$104,580	$104,580	$104,580	$104,580	$104,580	$104,580	$102,872	$102,872	$102,872	$102,872	$102,872	$1,246,418
(8)	Manchester Lateral	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$3,153,600
(9)	Millennium/AIM	$927,625	$933,474	$927,625	$933,474	$933,474	$927,625	$933,474	$927,625	$933,474	$933,474	$915,926	$933,474	$11,160,741
(10)	Niagara	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,718	$6,718	$6,718	$6,718	$6,718	$81,481
(11)	TCO (Pool)	$0	$0	$0	$0	$0	$0	$0	$525,113	$524,283	$525,473	$747,233	$764,949	$3,087,051
(12)	TCO App	$265,371	$263,371	$263,371	$263,371	$260,971	$260,971	$260,971	$0	$0	$0	$0	$0	$1,838,397
(13)	TCO App/M3/Storage	$418,695	$418,695	$418,695	$418,695	$418,695	$488,425	$488,426	$0	$0	$0	$0	$0	$3,070,324
(14)	TCO M3	$53,385	$53,013	$53,013	$53,013	$52,565	$52,565	$52,565	$0	$0	$0	$0	$0	$370,118
(15)	AGT M3	$0	$0	$0	$0	$0	$0	$0	$320,817	$320,817	$320,817	$320,817	$320,817	$1,604,085
(16)	TETCO SCT Long Haul	$0	$0	$0	$0	$0	$0	$0	$23,437	$23,433	$23,433	$24,008	$23,347	$117,658
(17)	TETCO CDS Long Haul	$0	$0	$0	$0	$0	$0	$0	$1,225,946	$1,227,508	$1,227,508	$1,217,302	$1,217,302	$6,115,565
(18)	Tetco M2	$858,269	$858,269	$858,269	$858,269	$862,264	$864,189	$864,189	$0	$0	$0	$0	$0	$6,023,720
(19)	TetcoM2/M3	$368,340	$368,338	$368,341	$368,340	$368,341	$481,492	$481,492	$0	$0	$0	$0	$0	$2,804,683
(20)	Tetco Refund	$0	($2,730,061)	$0	$0	$0	($108,759)	$0	$0	$0	$0	$0	$0	($2,838,819)
(21)	Transco Leidy	$9,197	$9,400	$7,884	$8,043	$8,043	$8,842	$9,001	$8,842	$9,001	$9,001	$8,525	$9,001	$104,779
(22)	Transco Refund	$0	$0	$0	($18,952)	$0	$0	$0	$0	$0	$0	$0	$0	($18,952)
(23)	Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(24)	TGP Long Haul	$0	$0	$0	$0	$0	$0	$0	$552,367	$552,366	$552,366	$552,362	$552,370	$2,761,831
(25)	TGP ConneXion	$0	$0	$0	$0	$0	$0	$0	$264,223	$264,222	$264,222	$264,222	$264,222	$1,321,113
(26)	Zone 4	$449,572	$449,572	$449,572	$449,572	$449,571	$449,572	$449,572	$0	$0	$0	$0	$0	$3,147,001
(27)	Zone 4 CXN	$263,953	$263,953	$263,953	$263,953	$263,953	$263,953	$263,953	$0	$0	$0	$0	$0	$1,847,674
(28)	AMA Credits	$0	($5,101)	($5,101)	($5,751)	($5,101)	($5,101)	($5,101)	($31,333)	($31,333)	($31,333)	($59,394)	($31,333)	($215,984)
(29)	Less Credits from Mkter Releases	($789,886)	($864,978)	($896,167)	($1,016,837)	($1,040,083)	($1,087,640)	($941,145)	($882,552)	($978,870)	($978,133)	($956,826)	($1,015,815)	($11,448,934)
(30)	**Supply Fixed - Supplier**													
(31)	Distrigas FCS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(32)	**Total**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(33)	**STORAGE FIXED COSTS - Facilities**													
(34)	Columbia FSS	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$23,199	$23,199	$143,338
(35)	Dominion GSS	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,412	$36,412	$36,412	$36,412	$36,412	$436,798
(36)	Dominion GSSTE	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,790	$46,790	$46,790	$46,790	$46,790	$561,297
(37)	Providence LNG	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$1,964,880
(38)	Tennessee FSMA	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$42,313	$42,313	$42,313	$42,313	$42,313	$514,370
(39)	Tetco FSS1	$2,397	$2,400	$2,456	$2,401	$2,404	$2,348	$2,349	$2,349	$2,359	$2,407	$2,400	$2,397	$28,668
(40)	Tetco SS1	$114,352	$114,404	$115,317	$114,417	$114,775	$113,943	$113,960	$113,960	$114,112	$114,898	$113,957	$113,908	$1,372,002
(41)	**STORAGE FIXED COSTS - Delivery**													
(42)	Storage Delivery	$311,804	$311,741	$311,741	$311,741	$306,709	$335,609	$344,381	$373,733	$373,148	$373,148	$387,581	$387,581	$4,128,916
(43)	**Confidential Pipeline and Peaking Supplies**	$442,496	$442,502	$530,593	$486,548	$486,547	$486,547	$486,548	$893,824	$3,577,545	$3,514,063	$3,524,577	$3,419,245	$18,291,033
(44)	**TOTAL FIXED COSTS**	$5,567,480	$2,777,190	$5,553,300	$5,391,037	$5,387,032	$5,431,471	$6,365,529	$6,172,559	$8,866,638	$8,836,970	$9,180,189	$9,050,245	$78,579,640

* Increase in demand rates for the period June 2020 through August 2020, resulting from Algonquin Gas Transmission, LLC rate settlement
(44) Sum[Lines (2) : (43)]

REDACTED

National Grid
Rhode Island - Gas

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

Supply Estimates Actuals for Filing

	Description	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(45)	**VARIABLE COMMODITY COSTS**													
(46)	AGT Citygate													
(47)	AIM at Ramapo													
(48)	Const Summer Refill													
(49)	Const Winter Refill													
(50)	Dawn via IGTS													
(51)	Dawn via PNGTS													
(52)	Dominion SP													
(53)	Dracut Supply													
(54)	Everett Long-Term													
(55)	Everett Swing													
(56)	Millennium													
(57)	Niagara													
(58)	TCO Appalachia													
(59)	TCO M3													
(60)	Tetco M2													
(61)	Tetco M3													
(62)	TGP Z4													
(63)	Transco Leidy													
(64)	Waddington													
(65)	Confidential Pipeline and Peaking Supplies													
(66)	Variable Transportation Costs													
(67)	Total Pipeline Commodity Charges	$3,600,118	$1,813,879	$802,884	$971,082	$1,145,334	$1,303,238	$2,220,317	$4,410,356	$9,471,840	$11,915,326	$14,961,635	$7,289,409	$59,905,420
(68)	**INJECTIONS & HEDGING IMPACT**													
(69)	Hedging	$1,652,722	$619,112	$476,792	$602,437	$418,795	$228,734	$661,718	$663,614	$1,754,079	$2,106,300	$659,969	$305,431	$10,149,703
(70)	Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(71)	Less: Costs of Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(72)	**TOTAL VARIABLE SUPPLY COSTS**	$5,252,840	$2,432,991	$1,279,677	$1,573,518	$1,564,129	$1,531,971	$2,882,035	$5,073,971	$11,225,919	$14,021,626	$15,621,605	$7,594,840	$70,055,122
(73)	**VARIABLE STORAGE COSTS**													
(74)	Underground Storage	$740,650	$381,773	$537,511	$93,662	$36,551	$62,110	$133,404	$487,251	$831,945	$1,033,914	$1,129,546	$1,121,965	$6,590,282
(75)	LNG Withdrawals and Trucking	$63,528	$51,845	$50,287	$76,450	$68,954	$65,962	$70,646	$146,539	$72,704	$74,454	$256,817	$157,896	$1,156,081
(76)	**TOTAL VARIABLE STORAGE COSTS**	$804,178	$433,617	$587,798	$170,112	$105,505	$128,072	$204,050	$633,790	$904,650	$1,108,367	$1,386,363	$1,279,861	$7,746,363
(77)	**TOTAL VARIABLE COSTS**	$6,057,018	$2,866,608	$1,867,475	$1,743,631	$1,669,634	$1,660,044	$3,086,085	$5,707,761	$12,130,569	$15,129,993	$17,007,967	$8,874,701	$77,801,486
(78)	**TOTAL SUPPLY COSTS**	$11,624,498	$5,643,799	$7,420,775	$7,134,668	$7,056,666	$7,091,515	$9,451,613	$11,880,319	$20,997,206	$23,966,964	$26,188,156	$17,924,946	$156,381,125

(67) Sum[Lines (46) : (66)]
(72) Sum[Lines (67) : (71)]
(76) Sum[Lines (74) : (75)]
(77) Line (72) + Line (76)
(78) Line (44) + Line (77)

REDACTED

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

Supply Estimates Actuals for Filing

	Description	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(79)	**Storage Costs for FT-2 Calculation**													
(80)	**Storage Fixed Costs - Facilities**	$416,596	$416,651	$417,620	$416,665	$417,026	$416,138	$416,156	$415,258	$415,420	$416,254	$428,810	$428,758	$5,021,352
(81)	**Storage Fixed Costs - Deliveries**	$432,908	$708,616	$796,706	$752,661	$747,629	$776,529	$785,301	$1,267,557	$3,950,693	$3,887,211	$3,912,158	$3,806,826	$21,824,794
(82)	**Sub-Total Storage Costs**	$849,504	$1,125,266	$1,214,326	$1,169,326	$1,164,655	$1,192,667	$1,201,457	$1,682,815	$4,366,113	$4,303,464	$4,340,968	$4,235,584	$26,846,147
(83)	**Tennessee Dracut for Peaking.**	$189,604	$189,604	$189,604	$189,604	$189,604	$189,604	$189,604	$186,508	$186,508	$186,508	$186,508	$186,508	$2,259,766
(84)	**Inventory Financing**	$76,279	$80,143	$81,871	$85,550	$89,402	$96,191	$99,934	$98,650	$91,074	$81,063	$72,015	$65,649	$1,017,822
(85)	**Supply related LNG O&M Costs**	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$115,939	$876,610
(86)	**Working Capital Requirement**	$12,815	$34,789	$34,279	$32,483	$32,924	$6,426	$8,512	$12,574	$23,152	$23,159	$23,363	$23,362	$267,839
(87)	**Total FT-2 Storage Fixed Costs**	$1,197,354	$1,498,954	$1,589,232	$1,546,115	$1,545,737	$1,554,040	$1,568,659	$2,049,699	$4,736,000	$4,663,346	$4,692,006	$4,627,042	$31,268,184
(88)	**System Storage MDQ (Dth)**	230,971	232,216	231,440	230,279	227,542	225,880	225,332	225,770	198,466	198,957	199,289	198,491	2,624,633
(89)	**FT-2 Storage Cost per MDQ (Dth)**	$5 1840	$6 4550	$6 8667	$6 7141	$6 7932	$6 8799	$6 9615	$9 0787	$23 8630	$23 4390	$23 5438	$23 3111	$11 9134
(90)	Pipeline Variable	$6,057,018	$2,866,608	$1,867,475	$1,743,631	$1,669,634	$1,660,044	$3,086,085	$5,707,761	$12,130,569	$15,129,993	$17,007,967	$8,874,701	$77,801,486
(91)	Less Non-firm Gas Costs	($56,997)	($53,042)	($15,734)	$5,568	($3,349)	($7,927)	($10,496)	($57,316)	($198,264)	($164,397)	($52,043)	($670)	($614,666)
(92)	Less Company Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(93)	Less Manchester St Balancing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(94)	Plus Cashout	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(95)	Less Mkter W/drawals/Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(96)	Mkter Over-takes/Undertakes	$47,849	($44,390)	$44,485	($44,617)	$22,326	($10,342)	($43,290)	($104,058)	($192,501)	$449,405	$211,798	$153,957	$490,622
(97)	Marketer Reconciliation Surcharge	$0	$0	$0	$0	$0	$0	$0	$0	$188,000	$0	$0	$0	$188,000
(98)	Plus Pipeline Srchg/Credit	$219,366	$214,776	$219,637	$210,411	$211,242	$206,775	$199,700	$206,260	$0	$0	$0	$0	$1,688,166
(99)	Less Mkter FT-2 Daily weather true-up	$24,908	($904)	$10,238	($1,746)	($166)	$0	($4,613)	($36,167)	$37,860	($26,438)	$44,648	$188,180	$235,799
(100)	**TOTAL FIRM COMMODITY COSTS**	$6,292,144	$2,983,048	$2,126,101	$1,913,246	$1,899,688	$1,848,549	$3,227,386	$5,716,480	$11,965,664	$15,388,563	$17,212,370	$9,216,169	$79,789,407

(82) Line (80) + Line (81)
(87) Sum[Lines (83) : (86)]
(89) Line (87) ÷ Line (88)
(90) Line (77)
(100) Sum[Lines (90) : (99)]

REDACTED

National Grid
Rhode Island - Gas

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

Schedule 3
Page 1 of 1

GCR Revenue

Description	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(1) **I. Fixed Cost Revenue**													
(2) (a) Low Load dth	2,707,105	2,108,558	842,394	574,273	530,136	489,988	710,322	1,546,738	2,711,846	4,364,731	4,870,211	4,026,399	25,482,701
(3) Fixed Cost Factor	$2 2336	$2 2363	$2 2329	$2 2354	$2 2419	$2 2388	$2 2339	$2 4750	$2 7401	$2 7528	$2 7417	$2 7424	
(4) Low Load Revenue	$6,046,626	$4,715,368	$1,880,951	$1,283,704	$1,188,503	$1,096,967	$1,586,813	$3,828,215	$7,430,771	$12,015,412	$13,352,444	$11,042,053	$65,467,828
(5) (b) High Load dth	63,510	57,683	45,155	38,763	29,789	28,225	38,614	50,599	69,007	87,323	87,253	82,908	678,829
(6) Fixed Cost Factor	$1 6768	$1 6794	$1 6786	$1 6789	$1 6793	$1 6791	$1 6785	$1 8710	$2 0901	$2 0895	$2 0903	$2 0899	
(7) High Load Revenue	$106,494	$96,872	$75,795	$65,081	$50,025	$47,391	$64,816	$94,671	$144,233	$182,460	$182,385	$173,270	$1,283,492
(8) Sub-total throughput Dth	2,770,615	2,166,242	887,550	613,036	559,925	518,213	748,936	1,597,337	2,780,853	4,452,054	4,957,463	4,109,307	26,161,530
(9) FT-2 Storage Revenue from marketers	$290,910	$283,899	$282,950	$281,531	$278,185	$276,153	$275,483	$276,018	$240,557	$241,151	$241,553	$240,586	$3,208,977
(10) **TOTAL Fixed Revenue**	$6,444,030	$5,096,139	$2,239,697	$1,630,316	$1,516,713	$1,420,511	$1,927,112	$4,198,905	$7,815,561	$12,439,023	$13,776,383	$11,455,910	$69,960,298
(11) **II. Variable Cost Revenue**													
(12) (a) Firm Sales dth	2,770,615	2,166,242	887,550	613,036	559,925	518,213	748,936	1,597,337	2,780,853	4,452,054	4,957,463	4,109,307	26,161,530
(13) Variable Supply Cost Factor	$2 9668	$2 9704	$2 9659	$2 9690	$2 9773	$2 9734	$2 9672	$2 9230	$2 9075	$2 9207	$2 9090	$2 9098	
(14) Variable Supply Revenue	$8,219,796	$6,434,515	$2,632,380	$1,820,135	$1,667,072	$1,540,832	$2,222,279	$4,668,958	$8,085,195	$13,002,944	$14,421,500	$11,957,369	$76,672,975
(15) (b) TSS Sales dth	16,361	16,173	1,115	202	1,248	745	1,691	8,126	15,186	23,963	29,433	28,253	142,497
(16) TSS Surcharge Factor	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	
(17) TSS Surcharge Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18) (c) Default Sales dth	5,844	5,097	1,510	(172)	1,510	1,890	1,674	3,291	7,269	11,301	9,700	7,082	55,996
(19) Variable Supply Cost Factor	$5 20	$5 20	$5 20	$5 20	$5 20	$5 20	$5 20	$5 20	$5 54	$5 46	$7 45	$7 38	
(20) Variable Supply Revenue	$30,394	$26,509	$7,855	($894)	$7,855	$9,827	$8,709	$17,114	$40,294	$61,654	$72,259	$52,232	$333,809
(21) (d) Peaking Gas Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22) (e) Deferred Responsibility	$1,969	$1,679	$919	$648	$6,343	$18,807	$1,345	$4,833	$5,381	$3,345	$1,799	$0	$47,069
(23) (e) FT-1 Storage and Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(24) **TOTAL Variable Revenue**	$8,252,159	$6,462,704	$2,641,154	$1,819,890	$1,681,270	$1,569,467	$2,232,332	$4,690,905	$8,130,870	$13,067,943	$14,495,558	$12,009,601	$77,053,853
(25) **III. Reduction to GCR**													
(26) (a) Low Load dth	2,707,105	2,108,558	842,394	574,273	530,136	489,988	710,322	1,546,738	2,711,846	4,364,731	4,870,211	4,026,399	25,482,701
(27) Low Load COVID Factor ($/dth)	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	($0 0970)	($0 1950)	($0 1959)	($0 1951)	($0 1952)	
(28) Low Load Revenue	$0	$0	$0	$0	$0	$0	$0	($150,078)	($528,774)	($855,018)	($950,161)	($785,754)	($3,269,785)
(29) (b) High Load dth	63,510	57,683	45,155	38,763	29,789	28,225	38,614	50,599	69,007	87,323	87,253	82,908	678,829
(30) High Load COVID Factor ($/dth)	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	($0 0760)	($0 1531)	($0 1530)	($0 1531)	($0 1531)	
(31) High Load Revenue	$0	$0	$0	$0	$0	$0	$0	($3,844)	($10,564)	($13,364)	($13,359)	($12,691)	($53,822)
(32) Total Reduction to GCR	$0	$0	$0	$0	$0	$0	$0	($153,922)	($539,339)	($868,382)	($963,520)	($798,445)	($3,323,607)
(33) **Total Gas Cost Revenue (w/o FT-2)**	$14,696,189	$11,558,842	$4,880,850	$3,450,206	$3,197,983	$2,989,977	$4,159,444	$8,735,887	$15,407,093	$24,638,584	$27,308,421	$22,667,067	$143,690,544

(2) Sch 6, Sum[lines (24) : (28), (30)]
(3) Line (4) ÷ Line (2)
(5) Sch 6, Sum[lines (22), (23), (29), (31)]
(6) Line (7) ÷ Line (5)
(8) Line (2) + Line (5)
(10) Line (4) + Line (7) + Line (9)
(12) Line (8)
(13) Line (14) ÷ Line (12)
(15) Sch 6, line (20)
(16) Company's website
(17) Line (15) x Line (16)
(18) Sch 6, line (61)
(19) Line (20) ÷ Line (18)
(22) Company Data
(24) Sum[Lines (14), (17), (20) (23)]
(26) Sch 6, Sum[lines (24) : (28), (30)]
(27) Line (28) ÷ Line (26)
(29) Sch 6, Sum[lines (22), (23), (29), (31)]
(30) Line (31) ÷ Line (29)
(32) Line (28) + Line (31)
(33) Line (10) + Line (24) + Line (32)

REDACTED

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

WORKING CAPITAL

	Description	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(1)	**Supply Fixed Costs**	$5,567,480	$2,777,190	$5,553,300	$5,391,037	$5,387,032	$5,431,471	$6,365,529	$6,172,559	$8,866,638	$8,836,970	$9,180,189	$9,050,245	$78,579,640
(2)	Less: System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	($20,574)	($1,305,540)	($1,242,058)	($1,252,572)	($1,147,240)	($4,967,984)
(3)	Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	($20,574)	($1,305,540)	($1,242,058)	($1,252,572)	($1,147,240)	($4,967,984)
(5)	Allowable Working Capital Costs	$5,567,480	$2,777,190	$5,553,300	$5,391,037	$5,387,032	$5,431,471	$6,365,529	$6,151,984	$7,561,097	$7,594,912	$7,927,617	$7,903,005	$73,611,656
(6)	Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(7)	Working Capital Requirement	$502,141	$250,480	$500,862	$486,227	$485,866	$489,874	$574,118	$554,858	$681,949	$684,999	$715,006	$712,786	
(8)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(9)	Return on Working Capital Requirement	$35,803	$17,859	$35,711	$34,668	$34,642	$34,928	$40,935	$39,561	$48,623	$48,840	$50,980	$50,822	
(10)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(11)	Interest Expense	$12,051	$6,012	$12,021	$11,669	$11,661	$11,757	$13,779	$13,317	$16,367	$16,440	$17,160	$17,107	
(12)	Taxable Income	$23,751	$11,848	$23,691	$22,999	$22,981	$23,171	$27,156	$26,245	$32,256	$32,400	$33,820	$33,715	
(13)	1 - Combined Tax Rate	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(14)	Return and Tax Requirement	$30,065	$14,997	$29,988	$29,112	$29,090	$29,330	$34,374	$33,221	$40,831	$41,013	$42,810	$42,677	
(15)	**Supply Fixed Working Capital Requiremen**	$42,116	$21,009	$42,009	$40,782	$40,751	$41,087	$48,153	$46,538	$57,197	$57,453	$59,970	$59,784	$556,850
(16)	**Supply Variable Costs**	$6,292,144	$2,983,048	$2,126,101	$1,913,246	$1,899,688	$1,848,549	$3,227,386	$5,716,480	$11,965,664	$15,388,563	$17,212,370	$9,216,169	$79,789,407
(17)	Less: Bal Related Syst Pressure Commodity to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20)	Allowable Working Capital Costs	$6,292,144	$2,983,048	$2,126,101	$1,913,246	$1,899,688	$1,848,549	$3,227,386	$5,716,480	$11,965,664	$15,388,563	$17,212,370	$9,216,169	$79,789,407
(21)	Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(22)	Working Capital Requirement	$567,500	$269,046	$191,757	$172,559	$171,336	$166,724	$291,084	$515,579	$1,079,205	$1,387,922	$1,552,414	$831,223	
(23)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(24)	Return on Working Capital Requirement	$40,463	$19,183	$13,672	$12,303	$12,216	$11,887	$20,754	$36,761	$76,947	$98,959	$110,687	$59,266	
(25)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(26)	Interest Expense	$13,620	$6,457	$4,602	$4,141	$4,112	$4,001	$6,986	$12,374	$25,901	$33,310	$37,258	$19,949	
(27)	Taxable Income	$26,843	$12,726	$9,070	$8,162	$8,104	$7,886	$13,768	$24,387	$51,046	$65,649	$73,429	$39,317	
(28)	1 - Combined Tax Rate[2]	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(29)	Return and Tax Requirement	$33,978	$16,109	$11,481	$10,332	$10,258	$9,982	$17,428	$30,870	$64,616	$83,100	$92,948	$49,768	
(30)	**Supply Variable Working Capital Requiremen**	$47,598	$22,566	$16,083	$14,473	$14,371	$13,984	$24,414	$43,243	$90,517	$116,410	$130,206	$69,717	$603,582

(1) Sch 1, line (4)
(2) Sch 1, line (5)
(3) Docket 4770
(4) Line (2) + Line (3)
(5) Line (1) + Line (4)
(6) Docket 4770
(7) [Line (5) x Line (6)] ÷ 365
(8) Docket 4770
(9) Line (7) x Line (8)
(10) Docket 4770
(11) Line (7) x Line (10)
(12) Line (9) - Line (11)
(13) Docket 4770
(14) Line (12) ÷ Line (13)
(15) Line (11) + Line (14)
(16) Sch 1, line (20)
(17) Sch 1, line (21)
(18) Docket 4770
(19) Line (17) + Line (18)
(20) Line (16) + Line (19)
(21) Docket 4770
(22) [Line (20) x Line (21)] ÷ 365
(23) Docket 4770
(24) Line (22) x Line (23)
(25) Docket 4770
(26) Line (22) x Line (25)
(27) Line (24) - Line (26)
(28) Docket 4770
(29) Line (27) ÷ Line (28)
(30) Line (26) + Line (29)

REDACTED

National Grid
Rhode Island - Gas

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

INVENTORY FINANCE

	Description	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(1)	**Storage Inventory Balance**	$7,339,795	$7,547,181	$7,386,030	$7,576,717	$7,815,992	$8,535,099	$8,754,267	$8,565,450	$8,042,722	$7,325,858	$6,699,522	$6,126,219	
(2)	Monthly Storage Deferral/Amortization	$157,781	$559,506	$1,024,123	$1,325,125	$1,617,472	$1,879,110	$2,194,483	$2,150,593	$1,689,752	$1,009,463	$416,953	$1	
(3)	**Subtotal**	$7,497,576	$8,106,687	$8,410,153	$8,901,842	$9,433,464	$10,414,209	$10,948,749	$10,716,043	$9,732,474	$8,335,320	$7,116,475	$6,126,220	
(4)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(5)	Return on Working Capital Requirement	$534,577	$578,007	$599,644	$634,701	$672,606	$742,533	$780,646	$764,054	$693,925	$594,308	$507,405	$436,800	$7,539,206
(6)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(7)	Interest Charges Financed	$179,942	$194,560	$201,844	$213,644	$226,403	$249,941	$262,770	$257,185	$233,579	$200,048	$170,795	$147,029	$2,537,741
(8)	Taxable Income	$354,635	$383,446	$397,800	$421,057	$446,203	$492,592	$517,876	$506,869	$460,346	$394,261	$336,609	$289,770	
(9)	1 - Combined Tax Rate	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(10)	Return and Tax Requirement	$448,906	$485,375	$503,545	$532,984	$564,814	$623,534	$655,539	$641,606	$582,717	$499,064	$426,088	$366,798	$6,330,968
(11)	Working Capital Requirement	$628,847	$679,936	$705,388	$746,628	$791,217	$873,475	$918,309	$898,791	$816,296	$699,112	$596,883	$513,827	$8,868,709
(12)	Monthly Average	$52,404	$56,661	$58,782	$62,219	$65,935	$72,790	$76,526	$74,899	$68,025	$58,259	$49,740	$42,819	$739,059
(13)	**LNG Inventory Balance**	$3,415,916	$3,359,565	$3,303,365	$3,338,032	$3,357,595	$3,348,116	$3,349,082	$3,398,061	$3,297,776	$3,262,629	$3,186,896	$3,266,372	
(14)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(15)	Return on Working Capital Requirement	$243,555	$239,537	$235,530	$238,002	$239,396	$238,721	$238,790	$242,282	$235,131	$232,625	$227,226	$232,892	$2,843,687
(16)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(17)	Interest Charges Financed	$81,982	$80,630	$79,281	$80,113	$80,582	$80,355	$80,378	$81,553	$79,147	$78,303	$76,486	$78,393	$957,202
(18)	Taxable Income	$161,573	$158,907	$156,249	$157,889	$158,814	$158,366	$158,412	$160,728	$155,985	$154,322	$150,740	$154,499	
(19)	1 - Combined Tax Rate	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(20)	Return and Tax Requirement	$204,523	$201,149	$197,784	$199,859	$201,031	$200,463	$200,521	$203,454	$197,449	$195,345	$190,810	$195,569	$2,387,956
(21)	Working Capital Requirement	$286,505	$281,778	$277,065	$279,972	$281,613	$280,818	$280,899	$285,007	$276,596	$273,648	$267,296	$273,962	$3,345,158
(22)	Monthly Average	$23,875	$23,482	$23,089	$23,331	$23,468	$23,401	$23,408	$23,751	$23,050	$22,804	$22,275	$22,830	$278,763
(23)	TOTAL GCR Inventory Financing Costs	$76,279	$80,143	$81,871	$85,550	$89,402	$96,191	$99,934	$98,650	$91,074	$81,063	$72,015	$65,649	$1,017,822

(3) Line (1) + Line (2)
(4) Docket 4770
(5) Line (3) x Line (4)
(6) Docket 4770
(7) Line (3) x Line (6)
(8) Line (5) - Line (7)
(9) Docket 4770
(10) Line (8) ÷ Line (9)
(11) Line (7) + Line (10)
(12) Line (11) ÷ 12
(14) Docket 4770
(15) Line (13) x Line (14)
(16) Docket 4770
(17) Line (13) x Line (16)
(18) Line (15) - Line (17)
(19) Docket 4770
(20) Line (18) ÷ Line (19)
(21) Line (17) + Line (20)
(22) Line (21) ÷ 12
(23) Line (12) + Line (22)

REDACTED

National Grid
Rhode Island - Gas

CONTAINS CONFIDENTIAL INFORMATION - DO NOT RELEASE

Schedule 6
Page 1 of 1

Actual Dth Usage for Filing

	THROUGHPUT (Dth) Rate Class	Apr-20 Actual (a)	May-20 Actual (b)	Jun-20 Actual (c)	Jul-20 Actual (d)	Aug-20 Actual (e)	Sep-20 Actual (f)	Oct-20 Actual (g)	Nov-20 Actual (h)	Dec-20 Actual (i)	Jan-21 Actual (j)	Feb-21 Actual (k)	Mar-21 Actual (l)	Apr-Mar (m)
(1)	**SALES**													
(2)	Residential Non-Heating	35,701	31,884	19,358	15,026	13,867	12,733	15,448	24,249	32,651	49,873	49,981	44,626	345,397
(3)	Residential Non-Heating Low Income	2,089	1,766	978	713	640	618	731	1,291	1,767	2,896	3,012	2,688	19,188
(4)	Residential Heating	1,925,877	1,524,285	602,351	402,672	364,713	341,335	484,559	1,082,842	1,911,972	3,079,189	3,399,975	2,795,586	17,915,355
(5)	Residential Heating Low Income	188,477	150,327	61,353	42,038	38,718	37,323	48,940	108,880	169,529	277,546	291,378	246,319	1,660,826
(6)	Small C&I	221,149	153,668	56,287	34,464	36,320	35,449	49,808	119,855	233,932	413,973	473,489	391,685	2,220,079
(7)	Medium C&I	296,219	218,546	110,408	85,100	81,927	69,814	101,349	192,957	322,356	487,636	549,707	457,550	2,973,569
(8)	Large LLF	55,257	42,207	8,942	9,299	6,951	5,346	9,342	27,728	51,650	77,602	120,309	101,152	515,784
(9)	Large HLF	20,259	16,298	15,457	13,291	11,305	9,958	15,011	17,253	21,173	28,963	27,754	29,044	225,764
(10)	Extra Large LLF	5,026	4,780	1,938	498	312	58	14,725	6,492	7,442	5,228	6,309	6,129	58,938
(11)	Extra Large HLF	4,200	6,309	9,362	9,733	3,925	4,834	7,331	7,665	13,195	5,185	6,116	6,277	84,133
(12)	Total Sales	2,754,254	2,150,069	886,434	612,834	558,677	517,468	747,245	1,589,210	2,765,666	4,428,091	4,928,030	4,081,054	26,019,032
(13)	**TSS**													
(14)	Small	1,540	1,150	2	27	70	(36)	(81)	165	665	910	1,265	1,173	6,851
(15)	Medium	9,614	12,156	1,113	58	1,102	479	1,223	3,661	8,371	13,151	15,628	14,682	81,238
(16)	Large LLF	3,946	1,440	0	117	25	220	455	4,159	5,930	9,495	12,150	12,124	50,061
(17)	Large HLF	1,261	1,427	0	0	52	83	94	141	221	406	389	274	4,347
(18)	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20)	Total TSS	16,361	16,173	1,115	202	1,248	745	1,691	8,126	15,186	23,963	29,433	28,253	142,497
(21)	**Sales & TSS THROUGHPUT**													
(22)	Residential Non-Heating	35,701	31,884	19,358	15,026	13,867	12,733	15,448	24,249	32,651	49,873	49,981	44,626	345,397
(23)	Residential Non-Heating Low Income	2,089	1,766	978	713	640	618	731	1,291	1,767	2,896	3,012	2,688	19,188
(24)	Residential Heating	1,925,877	1,524,285	602,351	402,672	364,713	341,335	484,559	1,082,842	1,911,972	3,079,189	3,399,975	2,795,586	17,915,355
(25)	Residential Heating Low Income	188,477	150,327	61,353	42,038	38,718	37,323	48,940	108,880	169,529	277,546	291,378	246,319	1,660,826
(26)	Small C&I	222,689	154,817	56,289	34,491	36,390	35,414	49,727	120,020	234,597	414,883	474,755	392,858	2,226,930
(27)	Medium C&I	305,833	230,702	111,521	85,158	83,028	70,293	102,573	196,618	330,727	500,788	565,335	472,232	3,054,808
(28)	Large LLF	59,203	43,647	8,942	9,416	6,976	5,566	9,797	31,887	57,580	87,098	132,459	113,276	565,845
(29)	Large HLF	21,519	17,725	15,457	13,291	11,357	10,040	15,104	17,394	21,393	29,369	28,143	29,318	230,111
(30)	Extra Large LLF	5,026	4,780	1,938	498	312	58	14,725	6,492	7,442	5,228	6,309	6,129	58,938
(31)	Extra Large HLF	4,200	6,309	9,362	9,733	3,925	4,834	7,331	7,665	13,195	5,185	6,116	6,277	84,133
(32)	Total Sales & TSS Throughput	2,770,615	2,166,242	887,550	613,036	559,925	518,213	748,936	1,597,337	2,780,853	4,452,054	4,957,463	4,109,307	26,161,530
(33)	**FT-1 TRANSPORTATION**													
(34)	FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	0
(35)	FT-1 Medium	39,875	38,431	4,978	8,581	17,647	18,901	26,982	49,147	65,463	105,383	95,744	71,951	543,083
(36)	FT-1 Large LLF	72,569	60,840	(1,617)	(7,842)	13,100	16,332	27,229	74,224	110,752	185,815	163,349	118,607	833,357
(37)	FT-1 Large HLF	32,983	24,926	16,851	26,425	22,596	17,068	20,155	24,902	30,545	43,265	41,213	33,703	334,631
(38)	FT-1 Extra Large LLF	100,362	77,008	(7,572)	(8,602)	18,150	24,280	32,928	111,031	148,418	226,942	215,127	147,432	1,085,504
(39)	FT-1 Extra Large HLF	487,905	414,021	367,817	361,290	405,650	440,020	376,766	388,807	523,490	583,228	562,929	449,948	5,361,871
(40)	Default	5,844	5,097	1,510	(172)	1,510	1,890	1,674	3,291	7,269	11,301	9,700	7,082	55,996
(41)	Total FT-1 Transportation	739,538	620,323	381,967	379,679	478,653	518,491	485,735	651,402	885,936	1,155,933	1,088,061	828,723	8,214,441
(42)	**FT-2 TRANSPORTATION**													
(43)	FT-2 Small	19,347	14,451	5,709	4,010	3,741	3,330	5,031	10,968	19,809	32,316	37,376	30,090	186,178
(44)	FT-2 Medium	190,183	144,794	64,652	46,873	45,397	38,138	63,483	126,800	197,417	285,214	314,456	279,625	1,797,031
(45)	FT-2 Large LLF	156,577	115,345	36,944	18,352	15,031	16,147	31,730	91,406	148,342	235,254	280,675	241,752	1,387,555
(46)	FT-2 Large HLF	57,204	48,678	41,195	38,975	35,105	33,574	39,789	45,481	64,000	81,868	77,564	75,619	639,051
(47)	FT-2 Extra Large LLF	6,806	3,406	1,492	503	250	506	796	2,608	6,390	11,552	11,320	10,141	55,770
(48)	FT-2 Extra Large HLF	34,018	25,434	33,930	33,899	26,441	35,884	37,081	41,216	43,499	44,550	44,114	5,247	405,313
(49)	Total FT-2 Transportation	464,135	352,108	183,922	142,611	125,964	127,580	177,910	318,480	479,456	690,754	765,505	642,474	4,470,898
(50)	**Total THROUGHPUT**													
(51)	Residential Non-Heating	35,701	31,884	19,358	15,026	13,867	12,733	15,448	24,249	32,651	49,873	49,981	44,626	345,397
(52)	Residential Non-Heating Low Income	2,089	1,766	978	713	640	618	731	1,291	1,767	2,896	3,012	2,688	19,188
(53)	Residential Heating	1,925,877	1,524,285	602,351	402,672	364,713	341,335	484,559	1,082,842	1,911,972	3,079,189	3,399,975	2,795,586	17,915,355
(54)	Residential Heating Low Income	188,477	150,327	61,353	42,038	38,718	37,323	48,940	108,880	169,529	277,546	291,378	246,319	1,660,826
(55)	Small C&I	242,036	169,268	61,998	38,501	40,131	38,744	54,758	130,988	254,406	447,199	512,131	422,948	2,413,108
(56)	Medium C&I	535,891	413,927	181,151	140,611	146,072	127,332	193,038	372,566	593,607	891,384	975,535	823,807	5,394,922
(57)	Large LLF	288,349	219,831	44,269	19,926	35,106	38,045	68,757	197,517	316,673	508,166	576,482	473,636	2,786,756
(58)	Large HLF	111,706	91,329	73,503	78,691	69,057	60,682	75,049	87,776	115,938	154,502	146,920	138,639	1,203,793
(59)	Extra Large LLF	112,194	85,194	(4,141)	(7,601)	18,712	24,844	48,449	120,132	162,251	243,722	232,756	163,702	1,200,212
(60)	Extra Large HLF	526,123	445,764	411,110	404,921	436,016	480,738	421,179	437,688	580,184	632,963	613,159	461,472	5,851,316
(61)	Default	5,844	5,097	1,510	(172)	1,510	1,890	1,674	3,291	7,269	11,301	9,700	7,082	55,996
(62)	Total Throughput	3,974,288	3,138,673	1,453,439	1,135,327	1,164,541	1,164,284	1,412,581	2,567,219	4,146,245	6,298,740	6,811,028	5,580,505	38,846,870

Attachment RMS-3
Projected Gas Cost Balances

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Projected Gas Cost Deferred Balances

	Description	Nov-21 forecast	Dec-21 forecast	Jan-22 forecast	Feb-22 forecast	Mar-22 forecast	Apr-22 forecast	May-22 forecast	Jun-22 forecast	Jul-22 forecast	Aug-22 forecast	Sep-22 forecast	Oct-22 forecast	Nov - Oct
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	**I. Fixed Cost Deferred**													
(3)	Beginning Under/(Over) Recovery	$3,569,594	$2,593,333	($159,751)	($6,067,310)	($12,562,102)	($15,750,151)	($19,085,381)	($17,389,888)	($14,206,494)	($10,530,847)	($6,750,885)	($3,075,477)	$3,569,594
(4)	Fixed Costs (net of capacity release)	$5,896,129	$9,741,455	$9,737,455	$10,285,725	$10,285,725	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$6,420,090	$90,887,120
(5)	Supply Related System Pressure to DAC	($20,909)	($1,629,488)	($1,629,488)	($1,629,488)	($1,629,488)	($20,909)	($20,909)	($20,909)	($20,909)	($20,909)	($20,909)	($20,909)	($6,685,226)
(6)	NGPMP Credits	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($8,039,179)
(7)	Working Capital	$43,278	$59,755	$59,725	$63,764	$63,764	$47,138	$47,138	$47,138	$47,138	$47,138	$47,138	$47,138	$620,254
(8)	Supply Related LNG O & M	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$829,823
(9)	Total Supply Fixed Costs	$5,317,719	$7,570,942	$7,566,912	$8,119,221	$8,119,221	$5,845,540	$5,845,540	$5,845,540	$5,845,540	$5,845,540	$5,845,540	$5,845,540	$77,612,792
(10)	Fixed - Revenue	($6,297,144)	($10,325,317)	($13,471,168)	($14,605,086)	($11,292,249)	($9,162,884)	($4,130,696)	($2,645,923)	($2,156,769)	($2,056,409)	($2,165,087)	($2,871,924)	($81,180,652)
(11)	Prelim. Ending Under/(Over) Recovery	$2,590,169	($161,042)	($6,064,006)	($12,553,175)	($15,735,130)	($19,067,495)	($17,370,537)	($14,190,271)	($10,517,723)	($6,741,716)	($3,070,432)	($101,862)	
(12)	Month's Average Balance	$3,079,881	$1,216,146	($3,111,878)	($9,310,242)	($14,148,616)	($17,408,823)	($18,227,959)	($15,790,080)	($12,362,109)	($8,636,282)	($4,910,659)	($1,588,669)	
(13)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(14)	Interest Applied	$3,164	$1,291	($3,304)	($8,928)	($15,021)	($17,886)	($19,352)	($16,223)	($13,124)	($9,169)	($5,045)	($1,687)	($105,281)
(15)	Marketer Reconciliation	$0												$0
(16)	Fixed Ending Under/(Over) Recovery	$2,593,333	($159,751)	($6,067,310)	($12,562,102)	($15,750,151)	($19,085,381)	($17,389,888)	($14,206,494)	($10,530,847)	($6,750,885)	($3,075,477)	($103,548)	($103,548)
(17)	**II. Variable Cost Deferred**													
(18)	Beginning Under/(Over) Recovery	$7,128,552	$7,878,933	$9,462,957	$12,142,969	$11,281,933	$10,880,889	$6,283,516	$3,972,087	$2,576,795	$1,559,148	$769,430	($128,896)	$7,128,552
(19)	Variable Costs	$7,337,085	$12,624,035	$17,201,504	$14,953,292	$11,758,848	$5,244,070	$1,949,045	$1,216,273	$1,037,896	$1,140,875	$1,142,249	$3,007,443	$78,612,614
(20)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21)	Supply Related LNG O & M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(22)	Inventory Financing - LNG	$23,222	$22,621	$18,967	$16,234	$22,084	$23,469	$23,453	$23,298	$23,789	$23,167	$23,659	$23,915	$267,879
(23)	Inventory Financing - UG	$65,154	$49,714	$33,088	$17,814	$7,726	$8,151	$21,661	$28,220	$40,232	$53,954	$65,434	$76,888	$468,035
(24)	Working Capital	$54,047	$92,992	$126,711	$110,150	$86,619	$38,629	$14,357	$8,959	$7,645	$8,404	$8,414	$22,154	$579,082
(25)	Total Variable Costs	$7,504,695	$12,814,549	$17,405,457	$15,122,677	$11,900,464	$5,339,506	$2,033,704	$1,301,938	$1,134,749	$1,251,588	$1,264,943	$3,155,586	$80,229,855
(26)	Variable - Revenue	($6,762,020)	($11,239,725)	($14,736,908)	($15,994,938)	($12,313,266)	($9,945,692)	($4,350,574)	($2,700,592)	($2,154,590)	($2,042,541)	($2,163,598)	($2,951,676)	($87,356,120)
(27)	Prelim. Ending Under/(Over) Recovery	$7,871,227	$9,453,757	$12,131,506	$11,270,707	$10,869,131	$6,274,703	$3,966,646	$2,573,432	$1,556,954	$768,195	($129,225)	$75,015	
(28)	Month's Average Balance	$7,499,890	$8,666,345	$10,797,232	$11,706,838	$11,075,532	$8,577,796	$5,125,081	$3,272,760	$2,066,874	$1,163,672	$320,103	($26,941)	
(29)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(30)	Interest Applied	$7,705	$9,201	$11,463	$11,226	$11,758	$8,813	$5,441	$3,362	$2,194	$1,235	$329	($29)	$72,699
(31)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(32)	Variable Ending Under/(Over) Recovery	$7,878,933	$9,462,957	$12,142,969	$11,281,933	$10,880,889	$6,283,516	$3,972,087	$2,576,795	$1,559,148	$769,430	($128,896)	$74,986	$74,986
(33)	**III. COVID Deferral**													
(34)	Beginning Under/(Over) Recovery	$4,863,540	$4,492,133	$3,870,687	$3,053,486	$2,164,894	$1,481,049	$928,503	$687,516	$538,318	$419,378	$306,548	$186,844	$4,863,540
(35)	COVID - Revenue	($376,210)	($625,883)	($820,875)	($891,092)	($685,780)	($553,783)	($241,844)	($149,828)	($119,448)	($113,215)	($119,957)	($163,831)	($4,861,746)
(36)	Prelim. Ending Under/(Over) Recovery	$4,487,330	$3,866,250	$3,049,812	$2,162,394	$1,479,114	$927,266	$686,659	$537,688	$418,870	$306,163	$186,591	$23,013	
(37)	Month's Average Balance	$4,675,435	$4,179,192	$3,460,250	$2,607,940	$1,822,004	$1,204,157	$807,581	$612,602	$478,594	$362,770	$246,569	$104,929	
(38)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(39)	Interest Applied	$4,804	$4,437	$3,674	$2,501	$1,934	$1,237	$857	$629	$508	$385	$253	$111	$21,331
(40)	COVID Ending Under/(Over) Recovery	$4,492,133	$3,870,687	$3,053,486	$2,164,894	$1,481,049	$928,503	$687,516	$538,318	$419,378	$306,548	$186,844	$23,124	$23,124
(41)	**GCR Deferred Summary**													
(42)	Beginning Under/(Over) Recovery	$15,561,686	$14,964,399	$13,173,894	$9,129,145	$884,725	($3,388,213)	($11,873,362)	($12,730,286)	($11,091,382)	($8,552,321)	($5,674,907)	($3,017,529)	$15,561,686
(43)	Gas Costs	$13,306,645	$20,830,340	$25,403,809	$23,703,867	$20,509,423	$11,737,590	$8,442,565	$7,709,793	$7,531,416	$7,634,395	$7,635,769	$9,500,963	$163,946,576
(44)	Inventory Finance	$88,376	$72,335	$52,055	$34,048	$29,810	$31,620	$45,115	$51,518	$64,021	$77,122	$89,093	$100,803	$735,914
(45)	Working Capital	$97,325	$152,747	$186,436	$173,914	$150,383	$85,767	$61,495	$56,097	$54,784	$55,542	$55,552	$69,292	$1,199,336
(46)	NGPMP Credits	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($669,932)	($8,039,179)
(47)	Total Costs	$12,822,414	$20,385,490	$24,972,369	$23,241,897	$20,019,685	$11,185,045	$7,879,244	$7,147,477	$6,980,289	$7,097,127	$7,110,483	$9,001,126	$157,842,646
(48)	Revenue	($13,435,374)	($22,190,925)	($29,028,951)	($31,491,116)	($24,291,295)	($19,662,359)	($8,723,114)	($5,496,343)	($4,430,807)	($4,212,165)	($4,448,642)	($5,987,431)	($173,398,518)
(49)	Prelim. Ending Under/(Over) Recovery	$14,948,726	$13,158,965	$9,117,312	$879,926	($3,386,885)	($11,865,526)	($12,717,232)	($11,079,151)	($8,541,900)	($5,667,359)	($3,013,066)	($3,834)	$5,814
(50)	Month's Average Balance	$15,255,206	$14,061,682	$11,145,603	$5,004,536	($1,251,080)	($7,626,870)	($12,295,297)	($11,904,718)	($9,816,641)	($7,109,840)	($4,343,987)	($1,510,681)	
(51)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(52)	Interest Applied	$15,673	$14,928	$11,833	$4,799	($1,328)	($7,836)	($13,053)	($12,231)	($10,422)	($7,548)	($4,463)	($1,604)	($11,252)
(53)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(54)	Ending Under/(Over) Recovery W/ Interest	$14,964,399	$13,173,894	$9,129,145	$884,725	($3,388,213)	($11,873,362)	($12,730,286)	($11,091,382)	($8,552,321)	($5,674,907)	($3,017,529)	$\boxed{(\$5,438)}$	($5,438)

(3) RMS-1, pg 7, Line (17)(m)
(4) RMS-1, pg 5, Line (41)
(6) GSP-1
(7) RMS-1, pg 9, Line (17)
(8) RMS-1, pg 2, Line (8) ÷ 12
(9) Sum[(4)-(8)]
(10) RMS-1, pg 8, Line (10)
(11) Sum[Lines (3), (9), (10)]
(14) [Line (12) x Line (13)] ÷ 365 x Line (1)
(16) Sum[Lines (11), (14), (15)]
(18) Nov-21: RMS-1, pg 7, Line (35)(m)
(19) RMS-1, pg 6, Line (77)
(21) RMS-1, pg 3, Line (8) ÷ 12
(22) RMS-1, pg 11, Line (22)
(23) RMS-1, pg 11, Line (12)
(24) RMS-1, pg 9, Line (32)
(26) RMS-1, pg 8, Line (15)
(27) Sum[Lines (18), (25), (26)]
(28) [Line (18) + Line (27)] ÷ 2
(30) [Line (28) x Line (29)] ÷ 365 x Line (1)
(32) Sum[Lines (27), (30), (31)]
(34) RMS-1, pg 7, Line (43)(m)
(35) RMS-1, Pg 8, Line (23)
(36) Line (34) + Line (35)
(39) [Line (37) x Line (38)] ÷ 365 x Line (1)
(40) Line (36) + Line (39)
(42) Line (3) + Line (18) + Line (34)
(43) Sum[Lines (4),(8),(15),(19)-(21)]
(44) Line (22) + Line (23)
(45) Line (7) + Line (24)
(46) Line (6)
(47) Sum[Lines (43)-(46)]
(49) Sum[Lines (42), (47), (48)]
(50) [Lines (42) + Line (49)] ÷ 2
(52) Line (14) + Line (30) + Line (39)
(53) Line (31)
(54) Sum[Lines (49), (52), (53)]

Attachment RMS-4

Attachment RMS-4
Bill Impact Analysis
Includes the proposed GCR And DAC Factors

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Heating:

						Difference due to:					
(1)											
(2)	Annual	Proposed	Current				DAC				
(3)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(4)											
(5)	548	$1,023.00	$951.75	$71.25	7.5%	$41.71	$27.40	$0.00	$0.00	$0.00	$2.14
(6)	608	$1,115.00	$1,035.96	$79.04	7.6%	$46.27	$30.40	$0.00	$0.00	$0.00	$2.37
(7)	667	$1,205.44	$1,118.73	$86.71	7.8%	$50.76	$33.35	$0.00	$0.00	$0.00	$2.60
(8)	726	$1,295.88	$1,201.52	$94.36	7.9%	$55.23	$36.30	$0.00	$0.00	$0.00	$2.83
(9)	785	$1,386.25	$1,284.19	$102.06	7.9%	$59.75	$39.25	$0.00	$0.00	$0.00	$3.06
(10)	845	$1,478.21	$1,368.36	$109.85	8.0%	$64.30	$42.25	$0.00	$0.00	$0.00	$3.30
(11)	905	$1,570.22	$1,452.57	$117.65	8.1%	$68.87	$45.25	$0.00	$0.00	$0.00	$3.53
(12)	964	$1,660.59	$1,535.29	$125.30	8.2%	$73.34	$48.20	$0.00	$0.00	$0.00	$3.76
(13)	1,023	$1,751.04	$1,618.03	$133.01	8.2%	$77.87	$51.15	$0.00	$0.00	$0.00	$3.99
(14)	1,082	$1,841.47	$1,700.81	$140.66	8.3%	$82.34	$54.10	$0.00	$0.00	$0.00	$4.22
(15)	1,142	$1,933.49	$1,785.03	$148.45	8.3%	$86.90	$57.10	$0.00	$0.00	$0.00	$4.45

Residential Heating Low Income:

							Difference due to:					
(16)												
(17)	Annual	Proposed	Current				Total Bill	DAC				
(18)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(19)												
(20)	548	$759.03	$707.36	$51.67	7.3%	$41.71	($16.71)	$25.12	$0.00	$0.00	$0.00	$1.55
(21)	608	$827.14	$769.83	$57.32	7.4%	$46.27	($18.53)	$27.86	$0.00	$0.00	$0.00	$1.72
(22)	667	$894.09	$831.21	$62.88	7.6%	$50.76	($20.33)	$30.57	$0.00	$0.00	$0.00	$1.89
(23)	726	$961.03	$892.61	$68.43	7.7%	$55.23	($22.13)	$33.27	$0.00	$0.00	$0.00	$2.05
(24)	785	$1,027.92	$953.92	$74.00	7.8%	$59.75	($23.93)	$35.96	$0.00	$0.00	$0.00	$2.22
(25)	845	$1,095.98	$1,016.34	$79.65	7.8%	$64.30	($25.75)	$38.71	$0.00	$0.00	$0.00	$2.39
(26)	905	$1,164.10	$1,078.79	$85.31	7.9%	$68.87	($27.59)	$41.47	$0.00	$0.00	$0.00	$2.56
(27)	964	$1,230.99	$1,140.13	$90.86	8.0%	$73.34	($29.38)	$44.17	$0.00	$0.00	$0.00	$2.73
(28)	1,023	$1,297.95	$1,201.50	$96.45	8.0%	$77.87	($31.19)	$46.87	$0.00	$0.00	$0.00	$2.89
(29)	1,082	$1,364.88	$1,262.89	$101.99	8.1%	$82.34	($32.98)	$49.57	$0.00	$0.00	$0.00	$3.06
(30)	1,142	$1,432.98	$1,325.36	$107.62	8.1%	$86.90	($34.80)	$52.29	$0.00	$0.00	$0.00	$3.23

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Non-Heating:

							Difference due to:				
(31)											
(32)	Annual	Proposed	Current				DAC				
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$387.87	$383.62	$4.26	1.1%	$8.81	($4.68)	$0.00	$0.00	$0.00	$0.13
(36)	158	$407.71	$403.03	$4.68	1.2%	$9.69	($5.15)	$0.00	$0.00	$0.00	$0.14
(37)	172	$427.67	$422.62	$5.05	1.2%	$10.53	($5.63)	$0.00	$0.00	$0.00	$0.15
(38)	189	$451.83	$446.29	$5.54	1.2%	$11.56	($6.19)	$0.00	$0.00	$0.00	$0.17
(39)	202	$470.29	$464.37	$5.92	1.3%	$12.36	($6.62)	$0.00	$0.00	$0.00	$0.18
(40)	220	$495.93	$489.45	$6.47	1.3%	$13.47	($7.19)	$0.00	$0.00	$0.00	$0.19
(41)	238	$521.49	$514.52	$6.97	1.4%	$14.56	($7.80)	$0.00	$0.00	$0.00	$0.21
(42)	251	$539.99	$532.64	$7.35	1.4%	$15.37	($8.24)	$0.00	$0.00	$0.00	$0.22
(43)	268	$564.15	$556.27	$7.88	1.4%	$16.40	($8.76)	$0.00	$0.00	$0.00	$0.24
(44)	282	$584.07	$575.76	$8.31	1.4%	$17.27	($9.21)	$0.00	$0.00	$0.00	$0.25
(45)	297	$605.38	$596.68	$8.70	1.5%	$18.16	($9.72)	$0.00	$0.00	$0.00	$0.26

Residential Non-Heating Low Income:

								Difference due to:				
(46)												
(47)	Annual	Proposed	Current				Total Bill	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$288.88	$286.03	$2.85	1.0%	$8.81	($0.92)	($5.12)	$0.00	$0.00	$0.00	$0.09
(51)	158	$303.60	$300.42	$3.19	1.1%	$9.69	($1.03)	($5.57)	$0.00	$0.00	$0.00	$0.10
(52)	172	$318.37	$314.94	$3.43	1.1%	$10.53	($1.11)	($6.10)	$0.00	$0.00	$0.00	$0.10
(53)	189	$336.22	$332.47	$3.75	1.1%	$11.56	($1.21)	($6.71)	$0.00	$0.00	$0.00	$0.11
(54)	202	$349.92	$345.91	$4.01	1.2%	$12.36	($1.30)	($7.18)	$0.00	$0.00	$0.00	$0.12
(55)	220	$368.87	$364.50	$4.37	1.2%	$13.47	($1.41)	($7.82)	$0.00	$0.00	$0.00	$0.13
(56)	238	$387.81	$383.07	$4.75	1.2%	$14.56	($1.54)	($8.42)	$0.00	$0.00	$0.00	$0.14
(57)	251	$401.50	$396.52	$4.99	1.3%	$15.37	($1.61)	($8.92)	$0.00	$0.00	$0.00	$0.15
(58)	268	$419.39	$414.07	$5.32	1.3%	$16.40	($1.72)	($9.52)	$0.00	$0.00	$0.00	$0.16
(59)	282	$434.11	$428.50	$5.61	1.3%	$17.27	($1.81)	($10.02)	$0.00	$0.00	$0.00	$0.17
(60)	297	$449.91	$444.02	$5.89	1.3%	$18.16	($1.91)	($10.54)	$0.00	$0.00	$0.00	$0.18

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I Small:

							Difference due to:					
(61)												
(62)	Annual	Proposed	Current				DAC					
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(64)											
(65)	830	$1,506.12	$1,394.94	$111.18	8.0%	$63.17	$44.67	$0.00	$0.00	$0.00	$3.34
(66)	919	$1,633.31	$1,510.26	$123.05	8.1%	$69.93	$49.43	$0.00	$0.00	$0.00	$3.69
(67)	1,010	$1,763.49	$1,628.23	$135.27	8.3%	$76.87	$54.34	$0.00	$0.00	$0.00	$4.06
(68)	1,099	$1,890.76	$1,743.61	$147.14	8.4%	$83.63	$59.10	$0.00	$0.00	$0.00	$4.41
(69)	1,187	$2,016.70	$1,857.76	$158.94	8.6%	$90.32	$63.85	$0.00	$0.00	$0.00	$4.77
(70)	1,277	$2,145.32	$1,974.28	$171.03	8.7%	$97.19	$68.71	$0.00	$0.00	$0.00	$5.13
(71)	1,367	$2,274.01	$2,090.96	$183.05	8.8%	$104.00	$73.56	$0.00	$0.00	$0.00	$5.49
(72)	1,456	$2,401.27	$2,206.31	$194.96	8.8%	$110.78	$78.33	$0.00	$0.00	$0.00	$5.85
(73)	1,544	$2,527.19	$2,320.44	$206.74	8.9%	$117.47	$83.07	$0.00	$0.00	$0.00	$6.20
(74)	1,635	$2,657.32	$2,438.37	$218.95	9.0%	$124.43	$87.95	$0.00	$0.00	$0.00	$6.57
(75)	1,725	$2,785.96	$2,554.98	$230.98	9.0%	$131.25	$92.80	$0.00	$0.00	$0.00	$6.93

C & I Medium:

							Difference due to:				
(76)											
(77)	Annual	Proposed	Current				DAC				
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(79)											
(80)	6,907	$9,678.13	$8,645.65	$1,032.48	11.9%	$525.64	$475.87	$0.00	$0.00	$0.00	$30.97
(81)	7,650	$10,605.21	$9,461.62	$1,143.59	12.1%	$582.16	$527.12	$0.00	$0.00	$0.00	$34.31
(82)	8,391	$11,529.30	$10,274.98	$1,254.32	12.2%	$638.56	$578.13	$0.00	$0.00	$0.00	$37.63
(83)	9,136	$12,458.66	$11,092.97	$1,365.68	12.3%	$695.22	$629.49	$0.00	$0.00	$0.00	$40.97
(84)	9,880	$13,386.87	$11,909.97	$1,476.90	12.4%	$751.87	$680.72	$0.00	$0.00	$0.00	$44.31
(85)	10,623	$14,313.91	$12,725.96	$1,587.95	12.5%	$808.39	$731.92	$0.00	$0.00	$0.00	$47.64
(86)	11,366	$15,241.01	$13,541.97	$1,699.04	12.5%	$864.97	$783.10	$0.00	$0.00	$0.00	$50.97
(87)	12,111	$16,170.34	$14,359.95	$1,810.39	12.6%	$921.62	$834.46	$0.00	$0.00	$0.00	$54.31
(88)	12,855	$17,098.58	$15,176.97	$1,921.61	12.7%	$978.27	$885.69	$0.00	$0.00	$0.00	$57.65
(89)	13,596	$18,022.72	$15,990.33	$2,032.39	12.7%	$1,034.65	$936.77	$0.00	$0.00	$0.00	$60.97
(90)	14,340	$18,950.92	$16,807.33	$2,143.59	12.8%	$1,091.28	$988.00	$0.00	$0.00	$0.00	$64.31

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(91)											
(92)											
(93)											
(94)											
(95)	37,587	$48,573.95	$44,559.50	$4,014.45	9.0%	$2,860.37	$1,033.65	$0.00	$0.00	$0.00	$120.43
(96)	41,634	$53,536.14	$49,089.45	$4,446.69	9.1%	$3,168.33	$1,144.96	$0.00	$0.00	$0.00	$133.40
(97)	45,683	$58,501.16	$53,622.03	$4,879.12	9.1%	$3,476.47	$1,256.28	$0.00	$0.00	$0.00	$146.37
(98)	49,731	$63,465.07	$58,153.60	$5,311.47	9.1%	$3,784.52	$1,367.61	$0.00	$0.00	$0.00	$159.34
(99)	53,777	$68,426.12	$62,682.51	$5,743.61	9.2%	$4,092.43	$1,478.87	$0.00	$0.00	$0.00	$172.31
(100)	57,825	$73,390.02	$67,214.07	$6,175.95	9.2%	$4,400.47	$1,590.20	$0.00	$0.00	$0.00	$185.28
(101)	61,873	$78,353.99	$71,745.68	$6,608.31	9.2%	$4,708.54	$1,701.52	$0.00	$0.00	$0.00	$198.25
(102)	65,920	$83,316.14	$76,275.60	$7,040.54	9.2%	$5,016.50	$1,812.82	$0.00	$0.00	$0.00	$211.22
(103)	69,967	$88,278.88	$80,806.13	$7,472.75	9.2%	$5,324.46	$1,924.11	$0.00	$0.00	$0.00	$224.18
(104)	74,016	$93,243.97	$85,338.74	$7,905.23	9.3%	$5,632.61	$2,035.46	$0.00	$0.00	$0.00	$237.16
(105)	78,063	$98,206.10	$89,868.64	$8,337.46	9.3%	$5,940.60	$2,146.74	$0.00	$0.00	$0.00	$250.12

C & I HLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(106)											
(107)											
(108)											
(109)											
(110)	41,956	$46,149.96	$41,573.70	$4,576.26	11.0%	$2,567.71	$1,871.26	$0.00	$0.00	$0.00	$137.29
(111)	46,471	$50,849.14	$45,780.40	$5,068.73	11.1%	$2,844.03	$2,072.64	$0.00	$0.00	$0.00	$152.06
(112)	50,991	$55,553.00	$49,991.31	$5,561.69	11.1%	$3,120.64	$2,274.20	$0.00	$0.00	$0.00	$166.85
(113)	55,507	$60,253.13	$54,198.85	$6,054.28	11.2%	$3,397.03	$2,475.62	$0.00	$0.00	$0.00	$181.63
(114)	60,028	$64,958.03	$58,410.61	$6,547.41	11.2%	$3,673.72	$2,677.27	$0.00	$0.00	$0.00	$196.42
(115)	64,545	$69,659.08	$62,619.02	$7,040.06	11.2%	$3,950.13	$2,878.73	$0.00	$0.00	$0.00	$211.20
(116)	69,062	$74,360.11	$66,827.41	$7,532.70	11.3%	$4,226.58	$3,080.14	$0.00	$0.00	$0.00	$225.98
(117)	73,583	$79,065.02	$71,039.13	$8,025.89	11.3%	$4,503.29	$3,281.82	$0.00	$0.00	$0.00	$240.78
(118)	78,099	$83,765.13	$75,246.66	$8,518.47	11.3%	$4,779.69	$3,483.23	$0.00	$0.00	$0.00	$255.55
(119)	82,619	$88,469.04	$79,457.61	$9,011.43	11.3%	$5,056.28	$3,684.81	$0.00	$0.00	$0.00	$270.34
(120)	87,137	$93,171.98	$83,667.75	$9,504.23	11.4%	$5,332.77	$3,886.33	$0.00	$0.00	$0.00	$285.13

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Extra-Large:

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(121)						Difference due to:					
(122)											
(123)											
(124)											
(125)	233,835	$230,423.57	$203,327.62	$27,095.95	13.3%	$17,794.86	$8,488.21	$0.00	$0.00	$0.00	$812.88
(126)	259,019	$254,572.70	$224,558.53	$30,014.16	13.4%	$19,711.36	$9,402.38	$0.00	$0.00	$0.00	$900.42
(127)	284,197	$278,716.64	$245,784.96	$32,931.68	13.4%	$21,627.39	$10,316.34	$0.00	$0.00	$0.00	$987.95
(128)	309,381	$302,865.72	$267,015.79	$35,849.93	13.4%	$23,543.90	$11,230.53	$0.00	$0.00	$0.00	$1,075.50
(129)	334,562	$327,012.25	$288,244.43	$38,767.81	13.4%	$25,460.17	$12,144.61	$0.00	$0.00	$0.00	$1,163.03
(130)	359,745	$351,160.48	$309,474.58	$41,685.90	13.5%	$27,376.60	$13,058.72	$0.00	$0.00	$0.00	$1,250.58
(131)	384,928	$375,308.71	$330,704.70	$44,604.01	13.5%	$29,293.02	$13,972.87	$0.00	$0.00	$0.00	$1,338.12
(132)	410,110	$399,456.13	$351,934.12	$47,522.01	13.5%	$31,209.36	$14,886.99	$0.00	$0.00	$0.00	$1,425.66
(133)	435,293	$423,604.32	$373,164.17	$50,440.15	13.5%	$33,125.79	$15,801.16	$0.00	$0.00	$0.00	$1,513.20
(134)	460,471	$447,748.29	$394,390.65	$53,357.65	13.5%	$35,041.84	$16,715.08	$0.00	$0.00	$0.00	$1,600.73
(135)	485,655	$471,897.42	$415,621.51	$56,275.91	13.5%	$36,958.35	$17,629.28	$0.00	$0.00	$0.00	$1,688.28

C & I HLF Extra-Large:

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(136)						Difference due to:					
(137)											
(138)											
(139)											
(140)	486,528	$418,982.68	$368,122.95	$50,859.73	13.8%	$29,775.53	$19,558.41	$0.00	$0.00	$0.00	$1,525.79
(141)	538,924	$463,437.47	$407,100.50	$56,336.98	13.8%	$32,982.14	$21,664.73	$0.00	$0.00	$0.00	$1,690.11
(142)	591,320	$507,891.53	$446,077.27	$61,814.26	13.9%	$36,188.77	$23,771.06	$0.00	$0.00	$0.00	$1,854.43
(143)	643,718	$552,347.94	$485,056.14	$67,291.79	13.9%	$39,395.57	$25,877.47	$0.00	$0.00	$0.00	$2,018.75
(144)	696,109	$596,798.12	$524,029.61	$72,768.51	13.9%	$42,601.87	$27,983.58	$0.00	$0.00	$0.00	$2,183.06
(145)	748,506	$641,253.76	$563,007.86	$78,245.90	13.9%	$45,808.58	$30,089.94	$0.00	$0.00	$0.00	$2,347.38
(146)	800,903	$685,709.37	$601,986.14	$83,723.23	13.9%	$49,015.25	$32,196.28	$0.00	$0.00	$0.00	$2,511.70
(147)	853,294	$730,159.52	$640,959.51	$89,200.01	13.9%	$52,221.58	$34,302.43	$0.00	$0.00	$0.00	$2,676.00
(148)	905,692	$774,615.96	$679,938.42	$94,677.54	13.9%	$55,428.38	$36,408.83	$0.00	$0.00	$0.00	$2,840.33
(149)	958,088	$819,069.98	$718,915.22	$100,154.75	13.9%	$58,634.99	$38,515.12	$0.00	$0.00	$0.00	$3,004.64
(150)	1,010,485	$863,525.62	$757,893.49	$105,632.13	13.9%	$61,841.68	$40,621.49	$0.00	$0.00	$0.00	$3,168.96

Attachment RMS-5
Redacted

Attachment RMS-5
FT-2 Demand Rate

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Summary of Marketer Transportation Factors

	Item (a)	Reference (b)	Proposed (c)	Billing Units (d)
(1)	FT-2 Demand Usage (Dt) Nov 2020 - Oct 2021	Pg 2, Line (21)	$12.2364	Dth/Mth
(2)	Storage and Peaking charge for FT-1 firm transportation Customers eligible for TSS	Pg 3, Line (5)	$0.9605	Per Dth

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Calculation of FT- 2 Demand Rate (per Dth)

	Description	Source Reference	Source Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Storage Fixed Costs	RMS-1 pg 5	Line (40)	[redacted]	
	Less:				
(2)	System Pressure to DAC			($6,685,226)	
(3)	Credits			$0	
(4)	Refunds			$0	
(5)	Total Credits	Sum [(2)-(4)]		($6,685,226)	
	Plus:				
(6)	Supply Related LNG O&M Costs	RMS-1 Pg 2	Line (8)	$829,823	
(7)	Working Capital Requirement	RMS-1 pg 10	Line (47)	$169,227	
(8)	FT Demand Everett	RMS-1 pg 4	Line (5)	$1,254,540	
(9)	Total Additions	Sum [(6)-(8)]		$2,253,590	
(10)	Total Storage Fixed Costs	(1) + (5) + (9)		[redacted]	
	Inventory Financing				
(11)	Underground	RMS-1 pg 11	Line (12)	$468,035	
(12)	LNG	RMS-1 pg 11	Line (22)	$267,879	
(13)	Total Storage Fixed Costs	(10) + (11) + (12)		[redacted]	
(14)	LNG Storage MDQ (Dth)	RMS-1 pg 13	Line (14)	[redacted]	
(15)	AGT	GSP-1			
(16)	TENN	GSP-1			
(17)	Total Storage MDQ	Sum [(14)-(16)]			
(18)	Storage MDQ X 12 Months	(17) x 12		[redacted]	MDCQ Dth
(19)	FT- 2 Demand Rate	(13) ÷ (18)		$12.0027	per MDCQ Dth
(20)	Uncollectible %	Docket 4770		1.91%	
(21)	Total FT-2 Demand Rate adjusted for Uncollectibles	(19) ÷ [(1 - (20)]		$12.2364	per MDCQ Dth
(22)	MDQ-U	Mkter MDQ Forecast		4,612	
(23)	MDQ-P	Mkter MDQ Forecast		15,384	
(24)	Marketer MDQs	(22) + (23)		19,996	Dth/Mth
(25)	FT-2 Storage Costs	(19) x (24) x 12 Months		**$2,880,020**	

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Calculation of FT-1 Storage and Peaking Charge Applied to Firm Transportation Customers Eligible for TSS

	Description	Source Reference	Source Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Total Storage Fixed Costs	Pg 2	Line (13)	[redacted]	
(2)	Usage (Dth) Nov 2021 - Oct 2022	RMS-1, pg 2	Line (15)	[redacted]	
(3)	Volumetric Rate	(1) ÷ (2)		$0.9422	
(4)	Uncollectible %	Docket 4770		1.91%	
(5)	Volumetric Rate Including Uncollectible	(3) ÷ [1 - (4)]		$0.9605	per dth
(6)	Storage & Peaking charge applied to FT-1 customers eligible for TSS	(5) ÷ 10		$0.0960	per therm

Attachment RMS-6

Attachment RMS-6
FT-2 Capacity Allocator Percentages

RI Gas Company
Capacity Assignment Table

			% of Peak Day Requirement				% of Total Capacity		
			Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	HLF	Res - Non-Heating	67.0%	8.0%	25.0%	100.0%	1.0%	0.8%	0.8%
2	HLF	Res - Non-Heating LI	67.0%	8.0%	25.0%	100.0%			
3	LLF	Res - Heating	52.0%	11.0%	37.0%	100.0%	61.9%	63.9%	63.9%
4	LLF	Res - Heating LI	52.0%	11.0%	37.0%	100.0%			
5	LLF	Small	52.0%	11.0%	37.0%	100.0%	7.7%	8.2%	8.2%
6	LLF	Med	52.0%	11.0%	37.0%	100.0%	9.2%	9.2%	9.2%
7	LLF	Large Low Load	52.0%	11.0%	37.0%	100.0%	2.0%	2.1%	2.1%
8	HLF	Large High Load	67.0%	8.0%	25.0%	100.0%	0.5%	0.4%	0.4%
9	LLF	XL Low Load	52.0%	11.0%	37.0%	100.0%	0.1%	0.1%	0.1%
10	HLF	XL High Load	67.0%	8.0%	25.0%	100.0%	0.1%	0.0%	0.0%
11	HLF	High Load Factor	67.0%	8.0%	25.0%	100.0%	6.4%	3.6%	3.6%
12	LLF	Low Load Factor	52.0%	11.0%	37.0%	100.0%	93.6%	96.4%	96.4%
13		Total	53.0%	11.0%	36.0%	100.0%	100.0%	100.0%	100.0%

Attachment RMS-7

Attachment RMS-7
COVID Deferral

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
COVID Deferral Recovery Factors

		COVID Deferal Balance (b)	2020/2021 Throughput (c)	Covid Deferral per Dth (d)
(1)	High Load	$100,674	655,553	$0.1535
(2)	Low Load	$4,762,865	26,898,975	$0.1770
(3)	Total	$4,863,540	27,554,528	

Col (b) (1): RMS-7, Page 2, Col (l), Line (14); (2): RMS-7, Page 2, Col (l)
Col (c) Company Forecast
Col (d) Col (b) ÷ Col (c)

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Projected COVID Deferral Balances

	Description	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov-Oct
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	**365**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Monthly Revenue Credit													
(1)	Low Load dth	1,546,738	2,711,846	4,382,453	4,870,211	4,026,399	2,606,931	1,510,433	824,017	507,219	595,478	613,567	801,559	
(2)	Low Load COVID Factor ($/dth)										($0.1950)	($0.1950)	($0.1950)	
(3)	Low Load Revenue	($150,078)	($528,774)	($855,018)	($950,161)	($785,754)	($508,795)	($294,801)	($160,763)	($99,002)	($116,118)	($119,646)	($156,304)	
(4)	High Load dth	50,599	69,007	87,323	87,253	82,908	65,309	50,001	41,702	33,925	34,547	37,622	38,418	
(5)	High Load COVID Factor ($/dth)										($0.1530)	($0.1530)	($0.1530)	
(6)	High Load Revenue	($3,844)	($10,564)	($13,364)	($13,359)	($12,691)	($9,998)	($7,656)	($6,383)	($5,193)	($5,286)	($5,756)	($5,878)	
(7)	Monthly Covid Credit	($153,922)	($539,339)	($868,382)	($963,520)	($798,445)	($518,793)	($302,457)	($167,146)	($104,195)	($121,404)	($125,402)	($162,182)	
	COVID Deferred - Low Load													
(8)	COVID Deferral Beginning Balance	$0	$150,155	$679,369	$1,535,562	$2,487,651	$3,276,463	$3,788,886	$4,087,866	$4,252,911	$4,356,481	$4,477,286	$4,601,593	$0
(9)	Revenue Credit	$150,078	$528,774	$855,018	$950,161	$785,754	$508,795	$294,801	$160,763	$99,002	$116,118	$119,646	$156,304	$4,725,214
(10)	Ending Balance Before Interest	$150,078	$678,929	$1,534,387	$2,485,723	$3,273,405	$3,785,258	$4,083,687	$4,248,629	$4,351,913	$4,472,599	$4,596,932	$4,757,897	
(11)	Average Monthly Balance	$75,039	$414,542	$1,106,878	$2,010,643	$2,880,528	$3,530,861	$3,936,286	$4,168,247	$4,302,412	$4,414,540	$4,537,109	$4,679,745	
(12)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(13)	Interest Applied	$77	$440	$1,175	$1,928	$3,058	$3,628	$4,179	$4,282	$4,568	$4,687	$4,661	$4,968	$37,651
(14)	COVID Deferral Ending Balance	$150,155	$679,369	$1,535,562	$2,487,651	$3,276,463	$3,788,886	$4,087,866	$4,252,911	$4,356,481	$4,477,286	$4,601,593	$4,762,865	$4,762,865
	COVID Deferred - High Load													
(15)	COVID Deferral Beginning Balance	$0	$3,846	$14,420	$27,807	$41,199	$53,940	$63,999	$71,726	$78,186	$83,465	$88,842	$94,693	$0
(16)	Revenue Credit	$3,844	$10,564	$13,364	$13,359	$12,691	$9,998	$7,656	$6,383	$5,193	$5,286	$5,756	$5,878	$99,972
(17)	Ending Balance Before Interest	$3,844	$14,411	$27,784	$41,165	$53,890	$63,938	$71,654	$78,109	$83,379	$88,751	$94,598	$100,571	
(18)	Average Monthly Balance	$1,922	$9,129	$21,102	$34,486	$47,544	$58,939	$67,826	$74,918	$80,783	$86,108	$91,720	$97,632	
(19)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
(20)	Interest Applied	$2	$10	$22	$33	$50	$61	$72	$77	$86	$91	$94	$104	$702
(21)	COVID Deferral Ending Balance	$3,846	$14,420	$27,807	$41,199	$53,940	$63,999	$71,726	$78,186	$83,465	$88,842	$94,693	$100,674	$100,674

(1) Col (a) - Col (i): Company Report; Col (j) - Col (l): Company Forecast
(2) Line (3) ÷ Line (1)
(3) Col (a) - Col (i): Company Report; Col (j) - Col (l): Line (1) x Line (2)
(4) Col (a) - Col (i): Company Report; Col (j) - Col (l): Company Forecast
(5) Line (6) ÷ Line (4)
(6) Col (a) - Col (i): Company Report; Col (j) - Col (l): Line (4) x Line (5)
(7) Line (3) + Line (6)
(9) Line (3)
(10) Line (8) + Line (9)
(11) [Line (8) + Line (10)] ÷ 2
(13) [Line (11) x Line (12)] ÷ 365 x Line (1)
(14) Line (10) + Line (13)
(16) Line (6)
(17) Line (15) + Line (16)
(18) [Line (15) + Line (17)] ÷ 2
(20) [Line (18) x Line (19)] ÷ 365 x Line (1)
(21) Line (17) + Line (20)

Testimony of
Gas Load Forecasting

JOINT DIRECT TESTIMONY

OF

GAS LOAD FORECASTING ("GLF") WITNESSES

THEODORE POE, JR.

AND

SHIRA HOROWITZ

September 1, 2021

Table of Contents

I. Introduction

Q. Mr. Poe, please state your name and business address.

A. My name is Theodore Poe, Jr. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am Manager, Gas Load Forecasting for National Grid USA Service Company, Inc. In this position, I am responsible for preparing forecasts of the resource requirements for the New England local gas distribution companies that operate as The Narragansett Electric Company (the Company), Boston Gas Company, and Colonial Gas Company, each d/b/a National Grid. In addition to the New England portfolios, I am responsible for preparing forecasts of the resource requirements for The Brooklyn Union Gas Company d/b/a National Grid NY (formerly KeySpan Energy Delivery New York), KeySpan Gas East Corporation d/b/a National Grid (formerly d/b/a KeySpan Energy Delivery Long Island), and Niagara Mohawk Power Corporation, all of which are located in New York. For purposes of this testimony, references to the Company relate solely to The Narragansett Electric Company.

Q. Please summarize your educational background and professional experience.

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science degree in Geology. From 1981 to 1989, I worked as a Research Associate with

Jensen Associates, Inc. of Boston, where I was responsible for developing a variety of computer-forecasting models to analyze natural gas supply and demand for interstate pipeline and local gas distribution companies. I joined Boston Gas Company in 1989, where I was responsible for modeling and forecasting customers' natural gas resource requirements and managing the resource planning process. In 1998-99, I assumed the same responsibilities for Essex Gas Company and Colonial Gas Company. In 2000, I assumed responsibility for modeling and forecasting the natural gas resource requirements of The Brooklyn Union Gas Company and KeySpan Gas East Corporation. In 2008, I assumed responsibility for modeling and forecasting the natural gas resource requirements for the Company and Niagara Mohawk Power Corporation.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Northeast Gas Association, the New England-Canada Business Council and the American Meteorological Society.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commissions?

A. Yes. I testified before the PUC in previous Gas Cost Recovery filings in Docket Nos. 4719, 4647, 4872, 4963 and 5066. I also submitted pre-filed written testimony in support of the Company's 2017 rate case filing in Docket No. 4770. In addition, I have testified in a number of proceedings before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

Q. Ms. Horowitz, please state your name and business address.

A. My name is Shira Horowitz, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am the Director, Economics and Gas Forecasting for the National Grid USA Service Company, Inc. ("Service Company"). Service Company provides engineering, financial, administrative, and other technical support to direct and indirect subsidiary companies of National Grid USA ("National Grid"), which include The Narragansett Electric Company d/b/a National Grid ("Narragansett" or the "Company"). I oversee the gas load forecasts for National Grid, as well as economic analysis.

Q. Please summarize your professional and educational background.

A. I have been in my current position at National Grid since May 2021 where I oversee gas load forecasting and general economic analysis for National Grid. Before that, from June 2019 through April 2021, I was the Manager of Economics and Load Forecasting at National Grid. Prior to joining National Grid, I worked at Con Edison in New York and PJM Interconnection in Pennsylvania.

I received a Bachelor of Engineering in Electrical Engineering from The Cooper Union in New York and a Doctor of Philosophy in Engineering and Public Policy from Carnegie Mellon University in Pennsylvania. I also completed a Fulbright Fellowship in Sustainable Power Generation in Stockholm, Sweden.

Q. Have you ever testified before the Rhode Island Public Utilities Commission ("PUC") or any other regulatory body?

A. Yes. I recently provided testimony at the evidentiary hearings in R.I.P.U.C. Docket No. 5076 and R.I.P.U.C. Docket No. 5127.

Q. What is the purpose of your joint testimony in this proceeding?

A. Our joint testimony supports the underlying retail and wholesale forecasts of natural gas customer requirements that are used to estimate gas costs in the Company's Gas Cost Recovery submission.

Q. Are you sponsoring any attachments?

A. Yes. We are sponsoring the following attachments with this testimony:

Attachment GLF-1	National Grid RI Retail Volume Forecast 2021 vs. 2020 Forecast
Attachment GLF-2	National Grid RI Retail Meter Count Forecast 2021 vs. 2020 Forecast
Attachment GLF-3	National Grid RI Economic Forecast 2021 vs. 2020 Forecast

Attachment GLF-4	National Grid RI Retail Volume Forecast by Rate Class 2021 vs. 2020 Forecast
Attachment GLF-5	National Grid RI Retail Meter Count Forecast by Rate Class 2021 vs. 2020 Forecast

Q. What was the source of the projected sendout requirements and costs used in this filing?

A. As in prior cost of gas filings, the Company used its internal billing and cost data and external economic data to forecast its sendout requirements.

II. <u>Summary of Retail and Wholesale Natural Gas Forecasts</u>

Q. How did the Company develop its retail and wholesale forecasts?

A. Annually, beginning in April, the Company uses the following five-step process to prepare its 10-year forecast of customer requirements:

1) Forecast retail demand requirements;
2) Develop reference-year wholesale sendout requirements using regression analysis;
3) Normalize forecast of customer requirements;
4) Determine design weather planning standards; and
5) Determine wholesale customer requirements under design weather conditions.

For the Company's forecast, "retail" refers to gas delivered and metered at customers' burner tips, and "wholesale" refers to gas received and metered flowing into the

Company's distribution system. The Company's retail forecast is prepared through econometric and statistical modeling of both customer count (meter count) and use-per-customer. This process is documented in greater detail in the Company's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2021/22 through 2025/26 dated June 30, 2021 (Long Range Plan) that was submitted to the Rhode Island Division of Public Utilities and Carriers and filed for information purposes with the Commission in Docket 5043. Billing data is modeled at the rate class level and further sub-categorized as sales or transportation (either capacity-eligible or capacity-exempt). The Company's volume forecast is the product of meter count and use-per-customer at the rate class level. The retail forecast takes into account the impact of the COVID-19 Pandemic on the Rhode Island economy and the impact of the Company's energy efficiency programs.

The Company's wholesale forecast is based on its retail forecast. The retail forecast is adjusted to correct for the billing lag inherent therein, and it is further adjusted to account for unaccounted-for gas. Unaccounted-for gas is the measure of the difference between gas supplies that are received and metered flowing into the Company's distribution system and gas delivered and metered at customers' burner tips. These two forecasts (retail and wholesale) serve as the annual basis of the Company's supply, engineering, and financial planning.

III. The 2021 Gas Forecast

Q. What is the role of the 2021 gas forecast in the Gas Cost Recovery proceeding?

A. With 72 percent of the Company's wholesale deliveries occurring between the months of November through March, as set forth in the pre-filed joint direct testimony of the Company's Gas Supply Panel, the Company's gas resource portfolio and gas supply purchase planning are designed to address its customers' needs during the winter peak period and throughout the year. Each year, the Company develops its gas forecast by accounting for the most recent heating season's actual customer usage patterns. This provides the Company with a growing set of historical data with which to build its econometric forecast using its most recent economic outlook.

The Company's forecast of sales and throughput requirements under normal weather conditions and under design winter conditions serves three purposes. First, the forecasts provide key inputs for the computation of National Grid's projected Gas Cost Recovery costs. Second, the Company's forecasts of design winter requirements form the basis for the Company's allocation of fixed costs between High Load Factor and Low Load Factor service classifications. Third, forecasts of total annual sales and throughput requirements provide the denominators used in the Company's computation of applicable charges on a dollars per therm basis. The Company's forecasts of future gas service requirements also serve as important indicators of the need for additional capacity to ensure the reliability of the Company's service, particularly during periods of extreme weather, as reflected in measures of design winter, cold snap, and design day requirements. The Company's long-range forecasts of service requirements also play an important role in assessing the economics of alternative gas supply resources.

Q. How do the forecasted sales requirements for 2021/22 compare to the prior retail forecast for 2020/21?

A. A comparison of the Company's 2020 gas forecast of firm retail volumes for the period November 2020 through October 2021 and its current firm retail volume forecast for November 2021 through October 2022 is shown in Table 1 below.

Table 1

	2020/21 Forecasted Volume (MMBtu)	**2021/22 Forecasted Volume (MMBtu)**
Residential Sales	20,169,756	20,504,326
C&I Sales	7,014,708	7,034,186
Total Sales	27,184,464	27,538,512
C&I Transportation	12,286,326	12,546,041
Total	39,470,789	40,084,553

Source: Attachment GLF-1

In summary, the 2021/22 forecast shows a 1.6 percent increase in Total Sales and Commercial and Industrial (C&I) Transportation customer volumes over the 2020/21 forecast, with Total Sales increasing by 1.3 percent and C&I Transportation increasing by 2.1 percent.

Attachment GLF-1 contains tables showing planning year[1] (PY) volumes from PY 2011 through PY 2030 for the Company's current (2021) volume forecast and last year's (2020) forecast. The data is presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts are provided in Attachment GLF-1 for visual comparison. The primary change in the forecast from 2020 to 2021 is the rebound from the COVID-19 pandemic in the Residential, C&I Sales, and C&I Firm Transportation volumes. The five-year per annum growth rate in volumes (excluding Other) from PY 2021 to PY 2026 is 2.1 percent, which is greater than the 1.6 percent per annum growth rate forecasted last year for the same period.

Attachment GLF-2 contains tables from PY 2011 through PY 2030 showing the Company's current (2021) meter count forecast and last year's (2020) forecast. The data is presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts are provided in Attachment GLF-2 for visual comparison. The primary change in the meter count forecast from 2020 to 2021 is a minor increase in the overall forecasted growth rate as the Rhode Island economy rebounds from the impact of COVID-19. The five-year per annum growth rate in meter count (excluding Other) from PY 2021 to

[1] The forecast planning year is November 1 through October 31.

PY 2026 is 1.0 percent, which is greater than the 0.9 percent per annum growth rate forecasted last year.

On a wholesale basis (see Attachment GSP-1, 'Delivery Point Volumes'), the Company forecasts sales volumes to be 29,230,000 MMBtu[2] for the period November 2021 through October 2022. Comparatively, in the Company's previous wholesale forecast for November 2020 through October 2021, as filed in Docket No. 5066, the sales volume was projected to be 28,670,000 MMBtu. Wholesale sales volume is projected to increase 2.0 percent as the Rhode Island economy recovers from the COVID-19 Pandemic.

Attachment GLF-3 contains tables for calendar year economic data from 1990 through 2023 for the Company's current (2021) forecast and last year's (2020) forecast. The data is presented for the following key indicators: Natural Gas Residential Price, Residential No. 2 Oil Price, the Gas-to-Oil Price Ratio, Rhode Island Gross Domestic Product, Households, and Non-Farm Employment. Charts are provided in Attachment GLF-3 for visual comparison. The overall 2021 economic forecast, as compared to the 2020 economic forecast, shows higher oil prices as compared to natural gas and slightly lower GDP and employment with the economic recovery from the COVID-19 pandemic.

[2] One million British thermal units (MMBtu).

Q. Have there been any changes to the forecasted sales requirements for 2021/22 as compared to the Company's Long Range Plan filed in Docket No. 5043 on June 30, 2021?

A. No. There are no changes to the forecasted sales requirements for 2021/22 as compared to the Company's Long Range Plan filed on June 30, 2021 in Docket No. 5043.

Q. How has the Company accounted for the effects of weather variations in the historic data inputs to its 2021 gas forecast?

A. In preparing the 2021 gas forecast, the Company used its monthly customer billing data (volume and number of customers) for the period September 2010 through February 2021 to forecast the number of customers and use-per-customer for each of the rate groups the Company analyzes. The Company obtained the historical monthly use-per-customer values by dividing volume of total billed therm for each month by the number of customers for the month. Weather, particularly heating degree days, plays a dominant role in modeling the use-per-customer behavior of the Company's customers under the wide range of weather observed in the historical period. The Company's forecast then applies its normalized heating degree days as the basis of its forecast of use-per-customer under normal weather conditions.

Q. How did the Company's 2020/21 forecast compare to the actual billings weather normalized for the same period?

A. According to the Company's most recent analysis where it normalized its actual billing data for November 2020 through February 2021 and forecasted March through October 2021, actual normalized Firm Sales customers plus C&I Transportation customers totaled 38,758,412 MMBtu. In the Company's 2020 Gas Cost Recovery filing (Docket 5066), the Company's normalized forecast volume for November 2020 through October 2021 was 39,842,972 MMBtu, as set forth in Table 1, above. Actual normalized sales were 2.7 percent lower than forecast, driven principally by the impact of the COVID-19 Pandemic.

Q. How has the Company addressed the effects of colder than normal weather on the development of its design winter and design day requirements?

A. The Company develops appropriate design day and design year planning standards to design a least-cost, reliable supply portfolio for its forecast period. 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. 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. The Company establishes its design standards using a three-step process. First, the Company performs statistical analyses of the coldest days and of the annual degree days recorded over a historical period. Second, the Company conducts cost-benefit analyses to evaluate the cost of maintaining the resources necessary to meet design-level demand versus the cost to customers of experiencing service curtailments. Third, the Company identifies design standards that would maintain reliability at the lowest cost.

Q. Does this conclude your testimony?

A. Yes.

<u>Attachments of Theodore Poe, Jr. and Shira Horowitz</u>

Attachment GLF-1	National Grid RI Retail Volume Forecast 2021 vs. 2020 Forecast

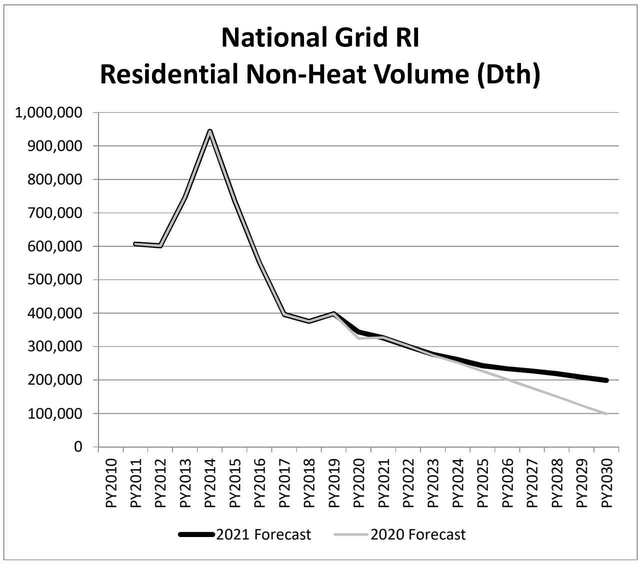
2021 National Grid RI Volume Forecast (Dth) — Chart III-B-1
Planning Year (Nov-Oct) — Page 1 of 2

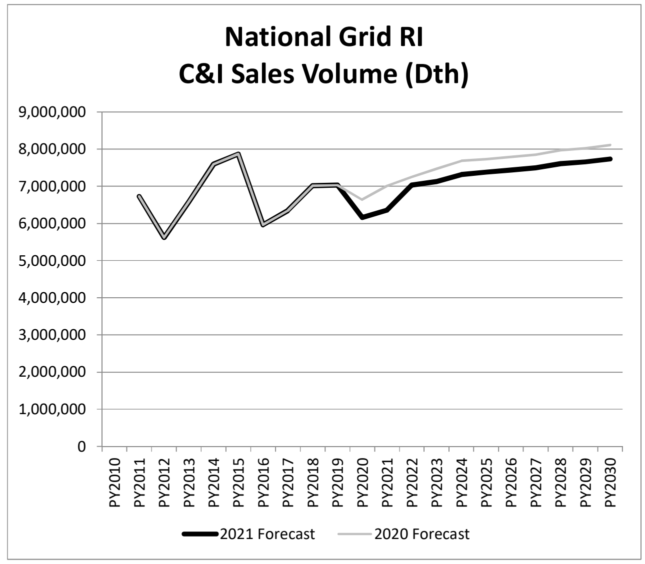
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,726,982	7,680,544	2,569,158	35,321,323	2,267,651	37,588,973
PY2012	601,399	14,783,757	5,621,832	7,610,425	2,333,884	30,951,297	2,195,914	33,147,211
PY2013	746,890	17,315,788	6,583,721	8,278,483	3,049,869	35,974,752	2,014,144	37,988,895
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	18,594,274	6,348,282	8,698,747	3,950,370	37,987,422	1,860,594	39,848,016
PY2018	375,502	19,943,709	7,021,050	9,022,578	4,205,501	40,568,340	1,938,339	42,506,679
PY2019	397,877	20,381,718	7,033,149	8,768,235	4,469,173	41,050,152	2,012,027	43,062,179
PY2020	343,560	19,204,168	6,161,983	8,208,510	4,313,144	38,231,365	2,067,717	40,299,082
PY2021	325,747	18,874,655	6,358,826	7,907,310	4,334,777	37,801,316	2,045,839	39,847,155
PY2022	300,785	20,203,541	7,034,186	7,779,116	4,766,925	40,084,553	2,459,542	42,544,095
PY2023	276,392	20,488,801	7,126,983	8,050,746	4,832,976	40,775,897	2,499,722	43,275,619
PY2024	260,581	20,878,142	7,319,546	8,134,775	4,898,558	41,491,601	2,511,128	44,002,729
PY2025	242,867	21,008,058	7,382,548	8,080,974	4,908,508	41,622,955	2,495,241	44,118,195
PY2026	233,703	21,239,154	7,443,635	8,034,205	4,934,251	41,884,947	2,482,684	44,367,632
PY2027	226,965	21,467,738	7,503,053	7,989,121	4,959,688	42,146,566	2,470,607	44,617,173
PY2028	218,461	21,828,142	7,607,716	7,958,767	5,010,890	42,623,977	2,463,942	45,087,919
PY2029	208,599	21,934,358	7,656,121	7,914,767	5,031,032	42,744,877	2,451,954	45,196,830
PY2030	198,661	22,170,600	7,736,384	7,885,606	5,070,235	43,061,486	2,445,121	45,506,607
PY26/PY21	-6.4%	2.4%	3.2%	0.3%	2.6%	2.1%	3.9%	2.2%

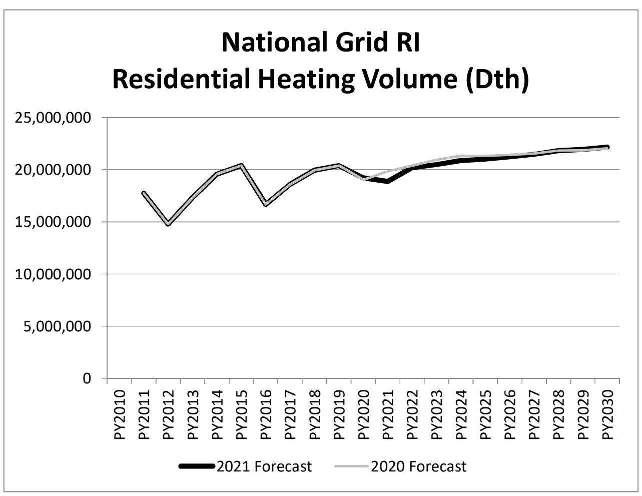
2020 National Grid RI Volume Forecast (Dth)
Planning Year (Nov-Oct)

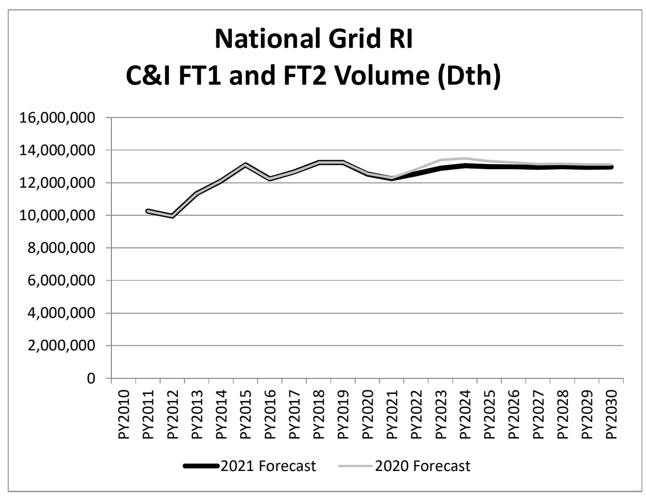
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,726,982	7,680,544	2,569,158	35,321,323	2,267,651	37,588,973
PY2012	601,399	14,783,757	5,621,832	7,610,425	2,333,884	30,951,297	2,195,914	33,147,211
PY2013	746,890	17,315,788	6,583,721	8,278,483	3,049,869	35,974,752	2,014,144	37,988,895
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
PY2028	150,402	21,841,445	7,974,627	8,517,749	4,646,435	43,130,657	1,861,753	44,992,409
PY2029	123,602	21,862,099	8,022,933	8,458,272	4,660,570	43,127,475	1,851,302	44,978,778
PY2030	98,317	22,039,250	8,113,332	8,430,431	4,697,161	43,378,491	1,847,671	45,226,162
PY26/PY21	-9.2%	1.6%	2.1%	1.4%	1.6%	1.6%	0.9%	1.5%

Chart III-B-1
Page 2 of 2









Attachment GLF-2

Attachment GLF-2 National Grid RI Retail Meter Count Forecast
2021 vs. 2020 Forecast

2021 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

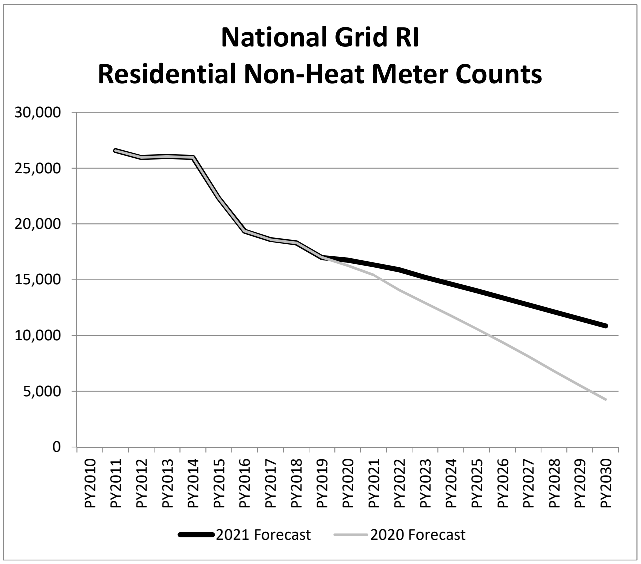
Chart III-B-2
Page 1 of 2

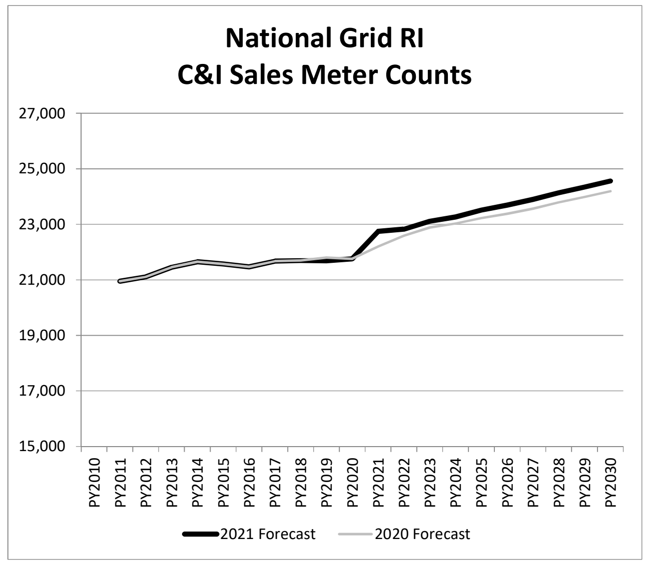
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,950	747	1,244	245,925	54	245,979
PY2012	25,955	200,463	21,105	734	1,399	249,656	65	249,721
PY2013	26,042	204,521	21,451	721	1,499	254,234	159	254,393
PY2014	25,958	206,568	21,651	699	1,486	256,362	178	256,540
PY2015	22,313	212,900	21,567	684	1,552	259,016	326	259,342
PY2016	19,351	218,314	21,467	674	1,680	261,486	488	261,974
PY2017	18,591	222,124	21,670	636	1,758	264,779	577	265,356
PY2018	18,299	225,211	21,693	624	1,776	267,603	637	268,240
PY2019	16,978	228,468	21,685	609	1,865	269,605	812	270,417
PY2020	16,750	230,384	21,757	595	1,823	271,309	870	272,179
PY2021	16,329	235,062	22,745	614	1,902	276,652	876	277,528
PY2022	15,883	238,872	22,826	619	1,911	280,111	880	280,991
PY2023	15,215	242,148	23,110	628	1,935	283,036	891	283,927
PY2024	14,617	245,378	23,268	634	1,947	285,844	896	286,740
PY2025	13,996	248,385	23,513	640	1,967	288,501	905	289,406
PY2026	13,372	251,226	23,689	645	1,981	290,913	912	291,825
PY2027	12,738	254,023	23,900	650	1,998	293,309	920	294,229
PY2028	12,105	256,778	24,132	655	2,017	295,687	928	296,615
PY2029	11,476	259,550	24,342	660	2,034	298,062	936	298,998
PY2030	10,852	262,321	24,556	664	2,050	300,443	944	301,387
PY26/PY21	-3.9%	1.3%	0.8%	1.0%	0.8%	1.0%	0.8%	1.0%

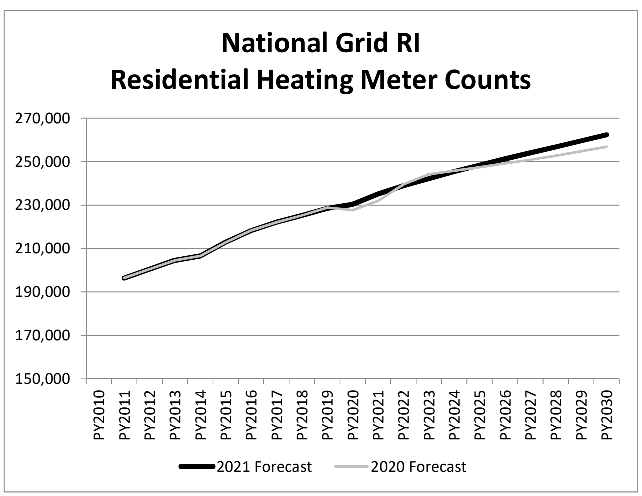
2020 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

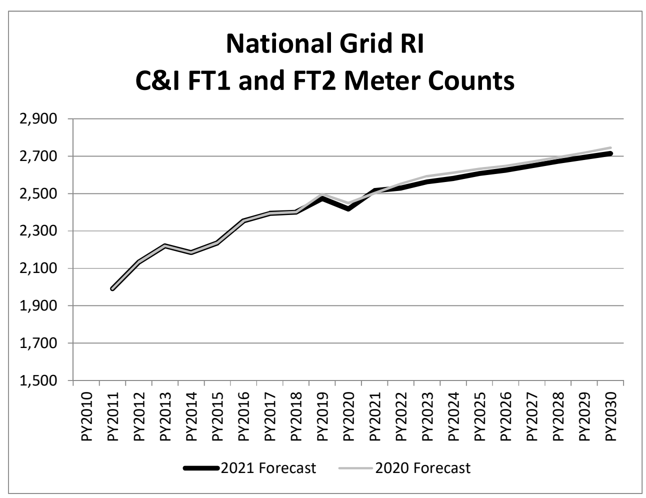
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,950	747	1,244	245,925	54	245,979
PY2012	25,955	200,463	21,105	734	1,399	249,656	65	249,721
PY2013	26,042	204,521	21,451	721	1,499	254,234	159	254,393
PY2014	25,958	206,568	21,651	699	1,486	256,362	178	256,540
PY2015	22,313	212,900	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
PY2028	6,820	252,737	23,786	655	2,039	286,037	922	286,959
PY2029	5,536	254,751	23,984	661	2,058	286,990	929	287,919
PY2030	4,257	256,858	24,192	669	2,076	288,052	937	288,989
PY26/PY21	-9.5%	1.4%	1.0%	1.3%	1.1%	0.9%	1.0%	0.9%

Chart III-B-2
Page 2 of 2









Attachment GLF-3

Attachment GLF-3 National Grid RI Economic Forecast
20210 vs. 2020 Forecast

2021 National Grid RI Economic Data
(Prices in 2019 $/Dth)

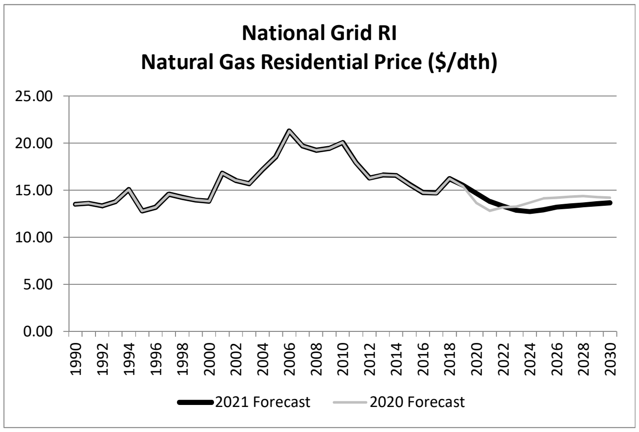
Chart III-B-3
Page 1 of 3

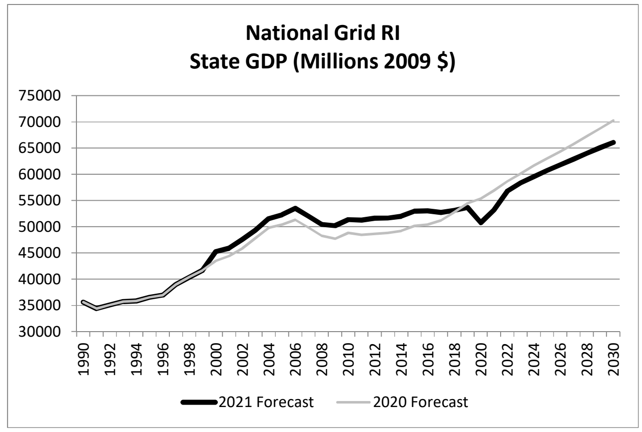
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR* *Residential Gas-to-Oil Price Ratio*	GDP GDP (2009 Millions of $)	HH Households (thousands)	EMPL Non-Farm Employment (thousands)
1990	*13.50*	*14.60*	*0.92*	*35616*	*377*	*454*
1991	*13.62*	*13.32*	*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*	45250	410	480
2001	*16.81*	*12.61*	*1.33*	45903	407	481
2002	*16.03*	*11.17*	*1.43*	47581	410	482
2003	*15.68*	*13.33*	*1.18*	49344	411	487
2004	*17.18*	*14.12*	*1.22*	51552	412	491
2005	*18.56*	*18.01*	*1.03*	52284	411	494
2006	*21.29*	*21.17*	*1.01*	53492	411	496
2007	*19.70*	*22.08*	*0.89*	51999	412	495
2008	*19.25*	*27.64*	*0.70*	50413	414	484
2009	*19.45*	*19.50*	*1.00*	50216	414	463
2010	20.06	25.04	*0.80*	51363	415	462
2011	17.92	31.02	*0.58*	51263	417	464
2012	16.28	33.03	*0.49*	51607	421	469
2013	16.62	32.44	*0.51*	51679	425	475
2014	16.57	31.26	*0.53*	52004	428	482
2015	15.61	21.83	*0.72*	52956	428	489
2016	14.75	17.33	*0.85*	53031	428	494
2017	14.70	19.98	*0.74*	52728	426	497
2018	16.23	22.12	*0.73*	53133	426	500
2019	15.53	21.22	*0.73*	53671	429	504
2020	14.66	16.75	*0.88*	50796	427	465
2021	13.79	19.99	*0.69*	53216	424	476
2022	13.28	20.19	*0.66*	56770	435	490
2023	12.86	22.03	*0.58*	58328	438	498
2024	12.73	23.01	*0.55*	59566	440	502
2025	12.91	23.87	*0.54*	60747	442	504
2026	13.21	24.77	*0.53*	61800	443	506
2027	13.32	25.17	*0.53*	62899	445	507
2028	13.45	25.76	*0.52*	63982	446	509
2029	13.56	26.11	*0.52*	65056	447	510
2030	13.65	26.63	*0.51*	66078	448	512
PY26/PY21	-0.86%	4.39%	-5.03%	3.04%	0.88%	1.22%

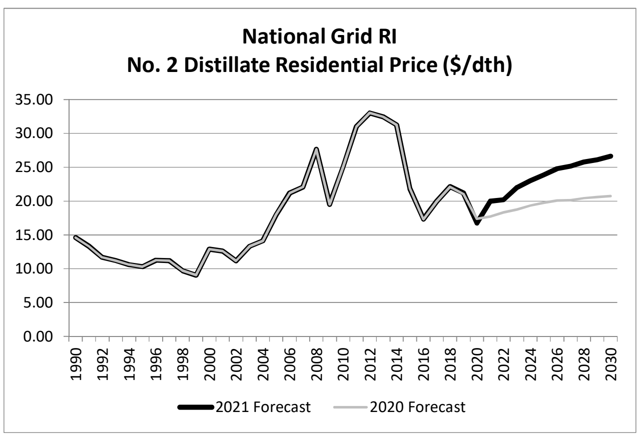
2020 National Grid RI Economic Data
(Prices in 2019 $/Dth)

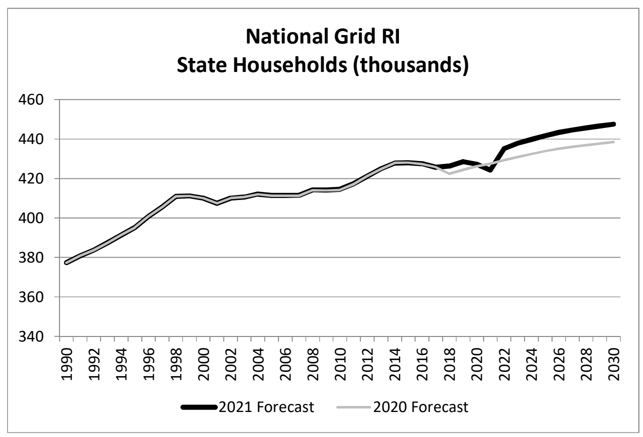
Chart III-B-3
Page 2 of 3

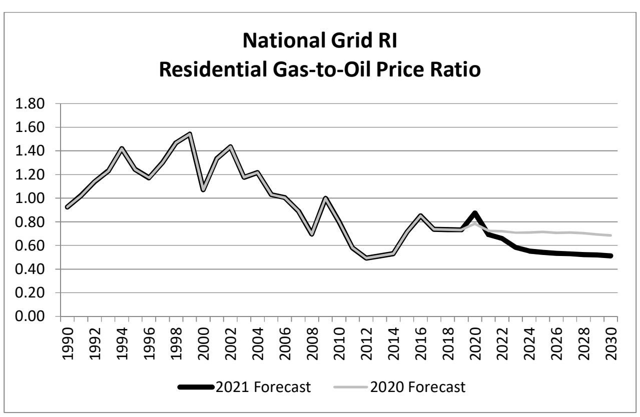
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR*	GDP (2005 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	13.50	14.60	*0.92*	35616	377	454
1991	13.62	13.32	*1.02*	34372	381	424
1992	13.33	11.69	*1.14*	35063	384	424
1993	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*	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*	48801	414	458
2011	17.92	31.03	*0.58*	48425	417	461
2012	16.28	33.04	*0.49*	48630	421	465
2013	16.62	32.45	*0.51*	48815	425	472
2014	16.57	31.26	*0.53*	49217	428	479
2015	15.61	21.83	*0.72*	50174	428	485
2016	14.74	17.32	*0.85*	50406	427	490
2017	14.69	19.96	*0.74*	51192	426	494
2018	16.23	22.12	*0.73*	52719	422	501
2019	15.42	21.07	*0.73*	54456	424	507
2020	13.64	17.38	*0.78*	55401	426	510
2021	12.82	17.73	*0.72*	56891	428	509
2022	13.19	18.32	*0.72*	58647	429	512
2023	13.26	18.73	*0.71*	60158	431	515
2024	13.68	19.34	*0.71*	61647	432	518
2025	14.13	19.75	*0.72*	63013	434	520
2026	14.19	20.08	*0.71*	64358	435	522
2027	14.30	20.14	*0.71*	65762	436	524
2028	14.35	20.43	*0.70*	67267	437	526
2029	14.27	20.62	*0.69*	68769	438	528
2030	14.19	20.73	*0.68*	70270	438	530
PY26/PY21	2.04%	2.52%	-0.46%	2.50%	0.35%	0.49%

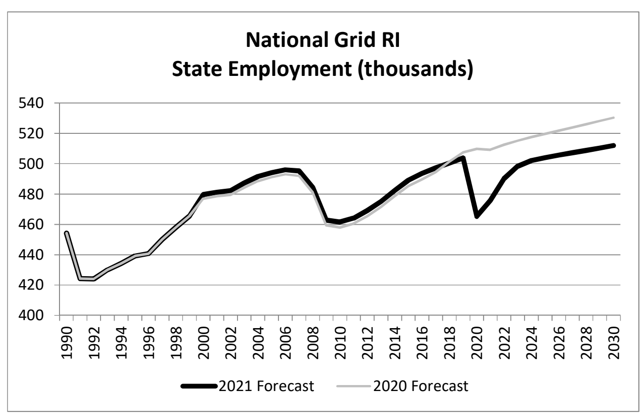

National Grid RI
Natural Gas Residential Price ($/dth)
2021 Forecast
2020 Forecast


National Grid RI
State GDP (Millions 2009 $)
2021 Forecast
2020 Forecast


National Grid RI
No. 2 Distillate Residential Price ($/dth)
2021 Forecast
2020 Forecast


National Grid RI
State Households (thousands)
2021 Forecast
2020 Forecast


National Grid RI
Residential Gas-to-Oil Price Ratio
2021 Forecast
2020 Forecast

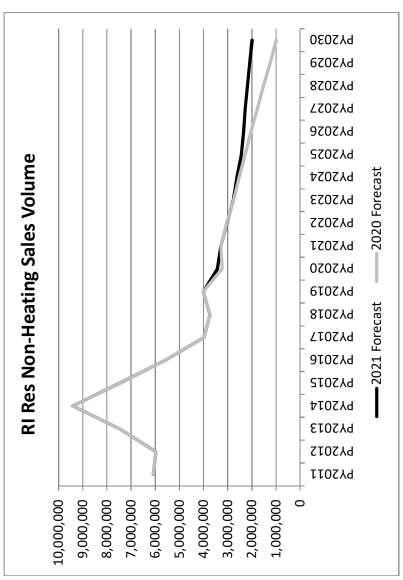

National Grid RI
State Employment (thousands)
2021 Forecast
2020 Forecast

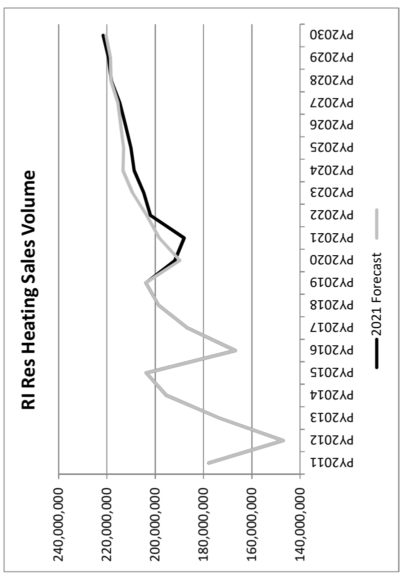
Attachment GLF-4

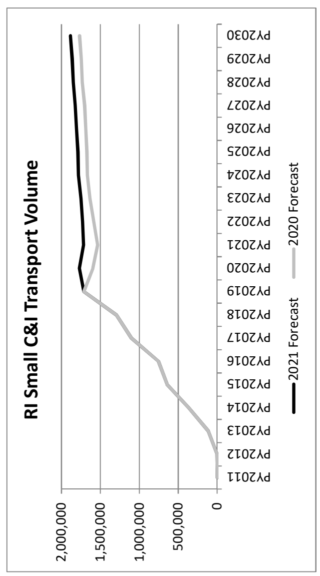
Attachment GLF-4 National Grid RI Retail Volume Forecast by Rate Class
2021 vs. 2020 Forecast

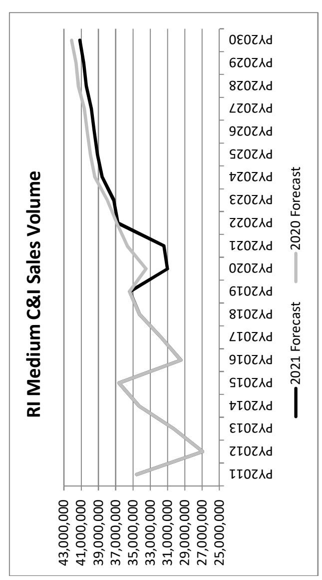
Chart III-B-4
Page 1 of 3

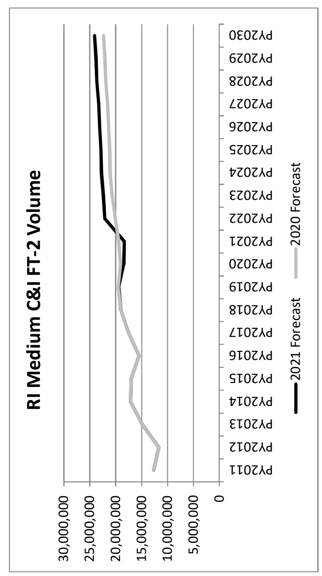
National Grid
2021 and 2020 Volume Forecasts by Rate Class
(Therms; Planning Year)

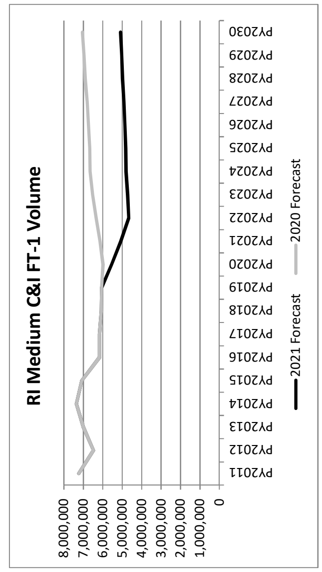




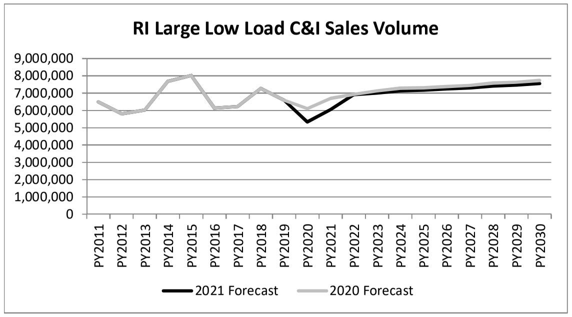


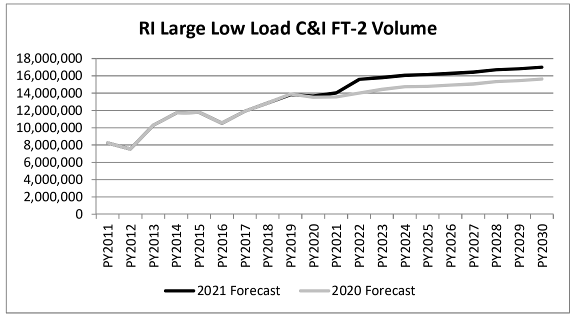


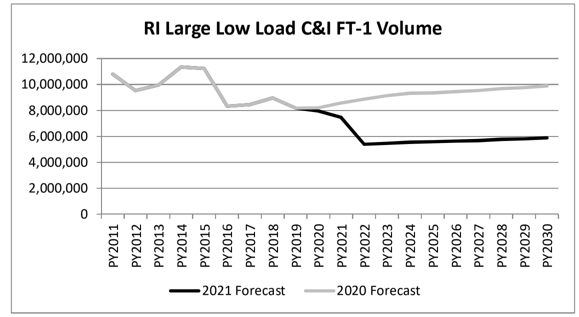


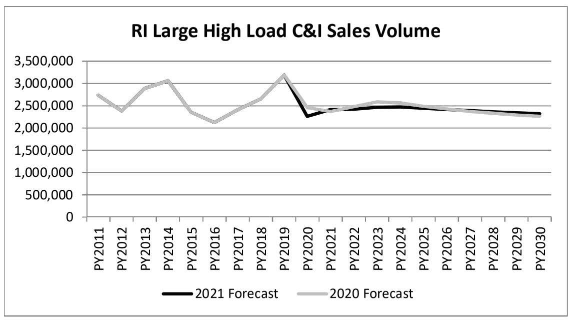


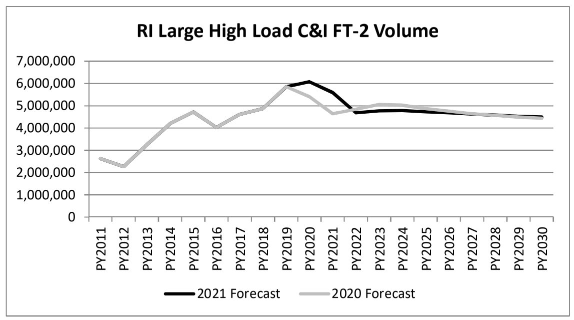
National Grid
2021 and 2020 Volume Forecasts by Rate Class
(Therms; Planning Year)

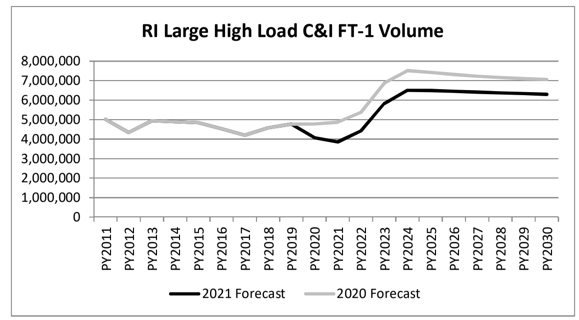


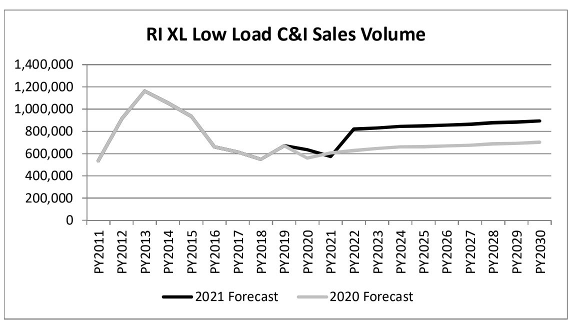


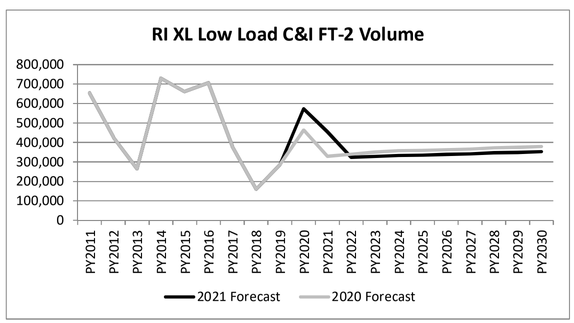


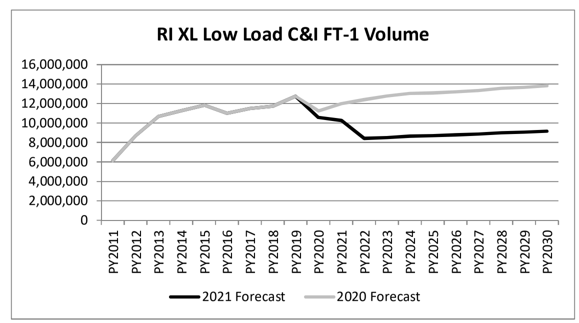




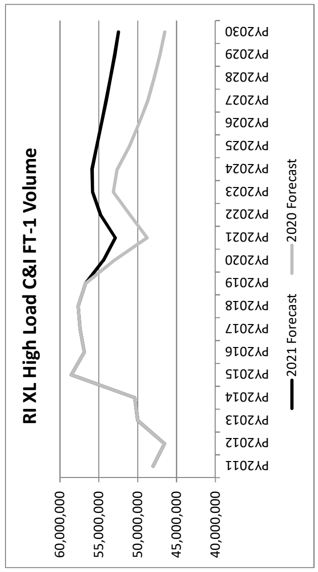


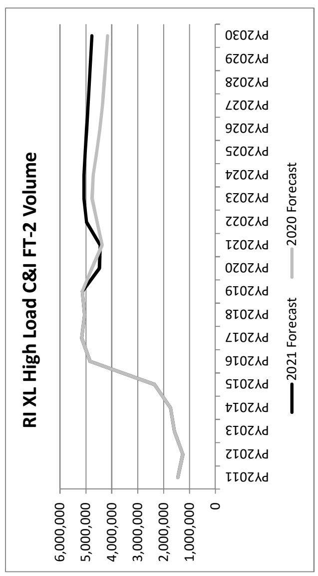


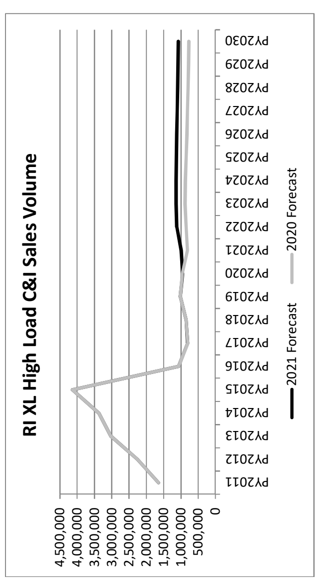


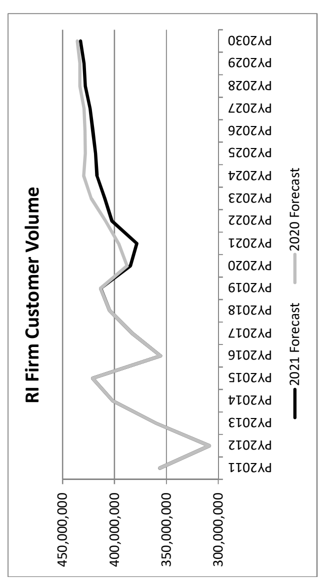


National Grid
2021 and 2020 Volume Forecasts by Rate Class
(Therms; Planning Year)









Attachment GLF-5

Attachment GLF-5 National Grid RI Retail Meter Count Forecast by Rate Class 2021 vs. 2020 Forecast

Chart III-B-5
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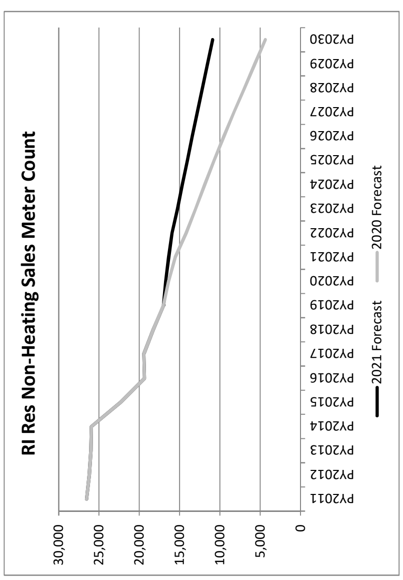
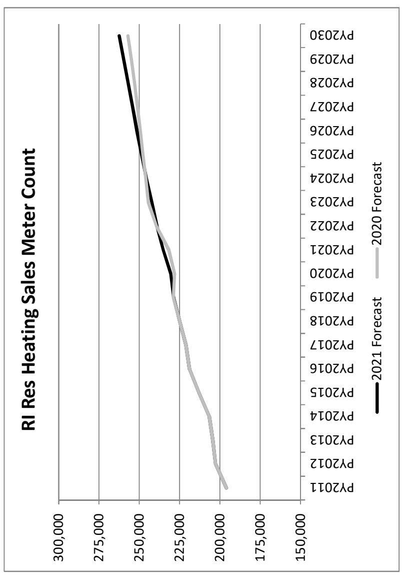
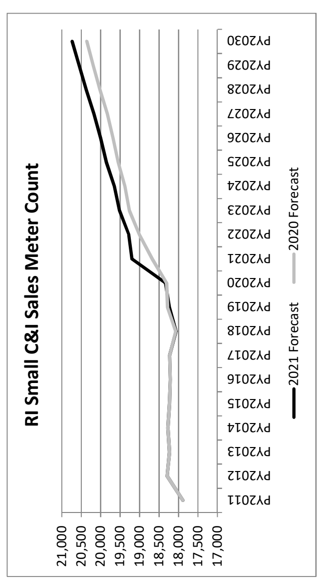
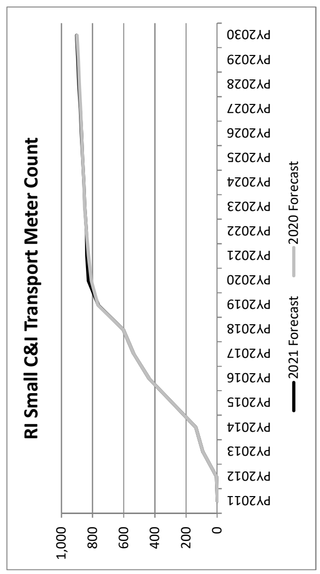
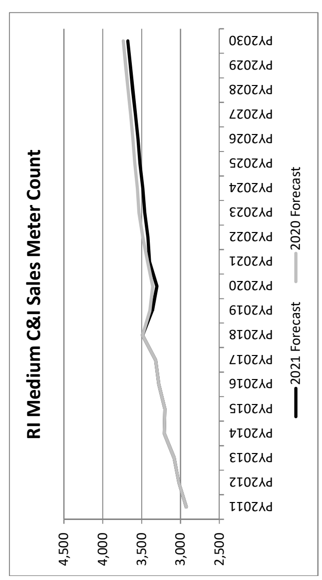
National Grid
2021 and 2020 Meter Count Forecasts by Rate Class
(end of Planning Year)

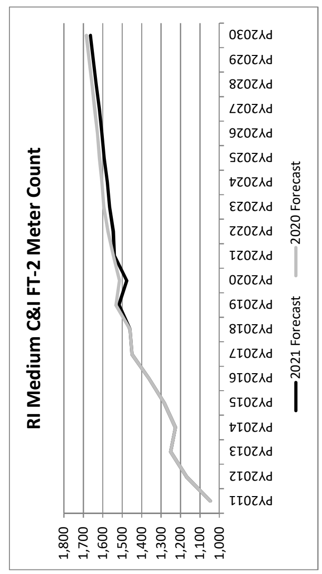


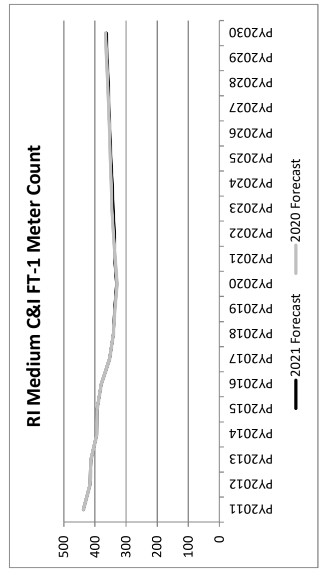




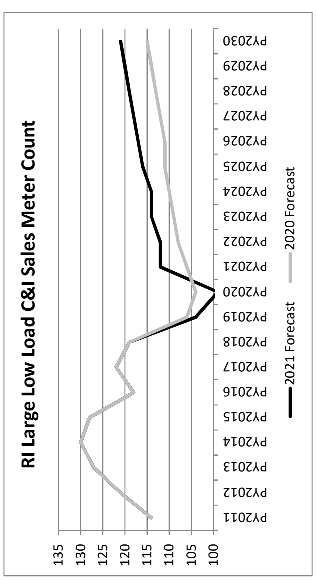


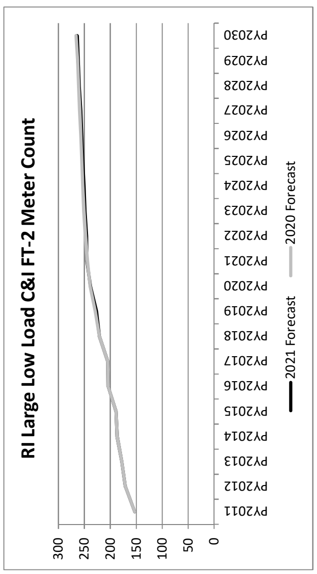


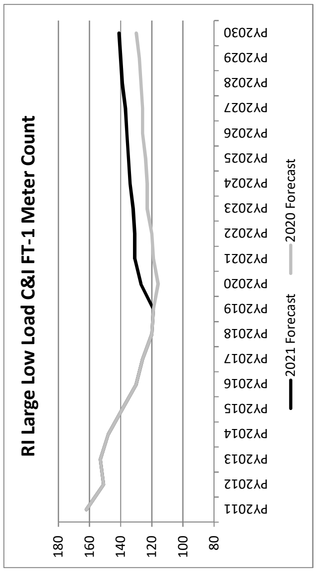


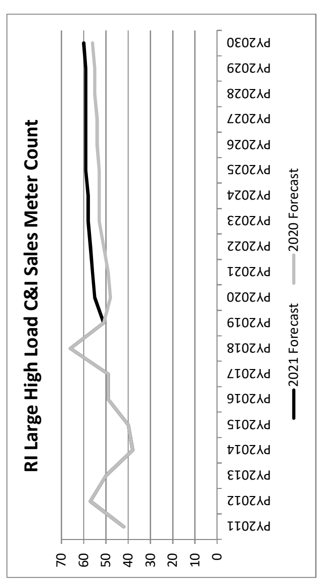


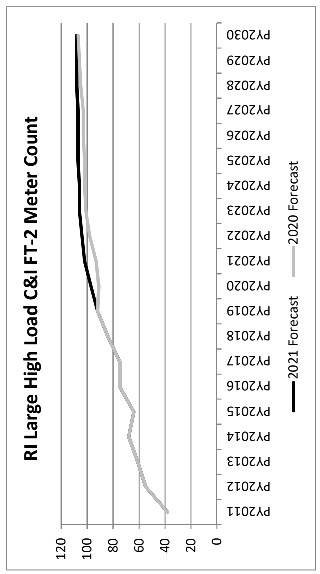
National Grid
2021 and 2020 Meter Count Forecasts by Rate Class
(end of Planning Year)

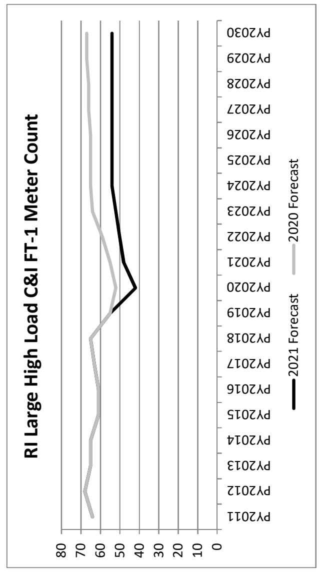


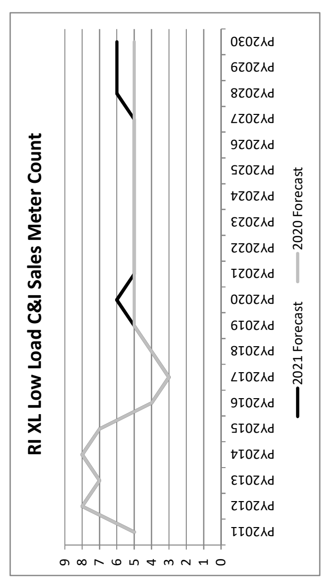


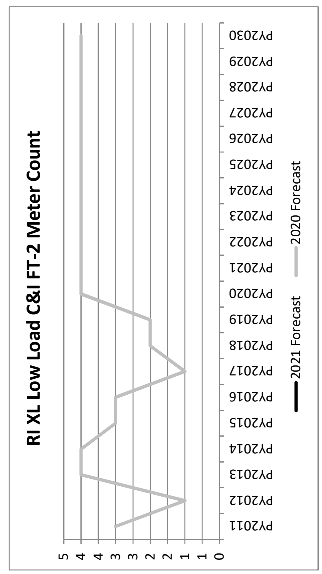


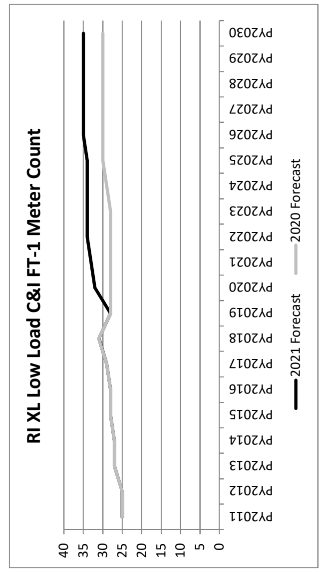












National Grid
2021 and 2020 Meter Count Forecasts by Rate Class
(end of Planning Year)