

The Narragansett Electric Company  
d/b/a National Grid

## **2018 GAS COST RECOVERY**

Testimony and Attachments of:

Nancy G. Culliford  
Elizabeth D. Arangio  
Ann E. Leary, and  
Theodore E. Poe, Jr.

August 31, 2018

Submitted to:  
Rhode Island Public Utilities Commission  
RIPUC Docket No. 4872

Submitted by:

**nationalgrid**

**Filing Letter &  
Motion**

August 31, 2018

**VIA HAND DELIVERY & ELECTRONIC MAIL**

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

**RE: Docket 4872 - 2018 Gas Cost Recovery Filing**

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's<sup>1</sup> annual Gas Cost Recovery (GCR) filing, which is being submitted pursuant to the Gas Cost Recovery Clause found in National Grid's gas tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A. The GCR filing reflects the customer class-specific factors necessary for National Grid to collect sufficient revenues to recover projected gas costs for the period November 1, 2018 through October 31, 2019.

This filing consists of the pre-filed testimony and attachments of Nancy G. Culliford, Elizabeth D. Arangio, Ann E. Leary, Theodore E. Poe, Jr., and John M. Protano. Ms. Culliford and Ms. Arangio provide joint testimony relative to National Grid's projected gas costs in support of the proposed GCR factors, as well as to modifications to National Grid's gas supply portfolio for the 2018 GCR period. Ms. Leary's testimony describes the development of the GCR factors proposed for effect November 1, 2018 and provides a bill impact analysis relative to those proposed factors. Mr. Poe's testimony provides support for the underlying wholesale and retail forecasts that National Grid uses to estimate gas costs in this filing. Mr. Protano's testimony discusses the results of the Gas Procurement Incentive Plan (GPIP) for the period April 1, 2017 through March 31, 2018.<sup>2</sup> Mr. Protano also discusses the results of the Natural Gas Portfolio Management Plan for the period April 1, 2017 through March 31, 2018.

As described in Ms. Leary's testimony, based on the GCR factors proposed for effect November 1, 2018 through October 31, 2019, an average residential heating customer using 845 therms per year will experience a total bill decrease of approximately \$91.73, or a 6.5 percent decrease from the

---

<sup>1</sup> The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

<sup>2</sup> On March 10, 2017, the PUC approved the Company's January 31, 2017 filing in Docket No. 4647, at Order No. 22717, to change the GPIP incentive year from a July to June reporting period to an April to March reporting period, to better align the incentive periods for the GPIP and the Natural Gas Portfolio Management Plan. Beginning this year and for every year hereafter, the GPIP incentive period will be April 1 through and including March 31.

Luly E. Massaro, Commission Clerk  
Docket 4872 – 2018 Annual Gas Cost Recovery  
August 31, 2018  
Page 2 of 2

existing rates. This decrease of \$91.73 is comprised of a decrease of \$40.14 in the GCR-related factors; a decrease of \$48.84 in the Distribution Adjustment Charge-related factors, filed on August 1, 2018 and supplemented today under separate cover in Docket No. 4846; and a decrease of \$2.75 in Gross Earnings Tax.

This filing also contains a Request for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) 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 of certain confidential gas-cost pricing information and forecasts, which are provided in the joint testimony of Ms. Culliford and Ms. Arangio and in Attachments NGC/EDA-1, NGC/EDA-2, and NGC/EDA-4 to their joint testimony, as well as in Attachments AEL-1, AEL-2, and AEL-5 to the testimony of Ms. Leary. Accordingly, National Grid has provided the PUC with one complete unredacted copy 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 401-784-7415.

Very truly yours,



Robert J. Humm

Enclosures

cc: Docket 4872 Service List  
Leo Wold, Esq.  
Al Mancini, Division  
John Bell, Division  
Bruce Oliver, Division

**STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS**

**RHODE ISLAND PUBLIC UTILITIES COMMISSION**

_____	)	
	)	
Annual Gas Cost Recovery Filing	)	Docket No. 4719
2018	)	
	)	
_____	)	

**MOTION OF THE NARRAGANSETT ELECTRIC  
COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE  
TREATMENT OF CONFIDENTIAL INFORMATION**

National Grid<sup>1</sup> hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

**I. BACKGROUND**

On August 31, 2018, National Grid submitted its 2018 Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. The GCR filing includes confidential gas cost pricing information, which is provided in (1) the pre-filed joint direct testimony of Nancy G. Culliford and Elizabeth D. Arangio regarding long-term supply contracts and requests for long term supply proposals; (2) Attachments NGC/EDA-1, NGC/EDA-2, and NGC/EDA-4 to Ms. Culliford and Ms. Arangio's joint testimony; and (3) Attachments AEL-1, AEL-2, and AEL-5 to the pre-filed direct testimony of Ann E. Leary. In accordance with Rule 1.2(g)(3), National Grid has

provided a redacted public version of the GCR filing, as well as an unredacted, confidential version.

Therefore, the Company requests that, pursuant to Rule 1.2(g), the PUC afford confidential treatment to the gas cost pricing information contained in the following: (1) the joint testimony of Ms. Culliford and Ms. Arangio regarding a long-term supply contract; (2) Attachments NGC/EDA-1, NGC/EDA-2, and NGC/EDA-4 to Ms. Culliford and Ms. Arangio's joint testimony; and (3) Attachments AEL-1, AEL-2, and AEL-5 to Ms. Leary's testimony.

## **II. LEGAL STANDARD**

Rule 1.2(g) of the PUC's Rules of Practice and Procedure 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 APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

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

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

---

<sup>1</sup> The Narragansett Electric Company d/b/a National Grid (National Grid).

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 v. Convention Ctr. Auth.*, 774 A.2d 40, 47 (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 – which is provided in the joint testimony of Ms. Culliford and Ms. Arangio; Attachments NGC/EDA-1, NGC/EDA-2, and NGC/EDA-4 to Ms. Culliford and Ms. Arangio's joint testimony; and Attachments AEL-1, AEL-2, and AEL-5 to Ms. Leary's testimony – is 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,

A handwritten signature in blue ink, appearing to be "RH", with a long horizontal flourish extending to the right.

---

Robert J. Humm, Esq. (#7920)  
National Grid  
280 Melrose Street  
Providence, RI 02907  
(401) 784-7415  
Dated: August 31, 2018

**Joint Testimony**  
**Cullford & Arango**  
**REDACTED**

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018

---

**JOINT DIRECT TESTIMONY**

**OF**

**NANCY G. CULLIFORD**

**AND**

**ELIZABETH D. ARANGIO**

**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO**  
**AUGUST 31, 2018**

---

**Table of Contents**

I. Introduction..... 1

II. Projected Gas Costs ..... 6

III. Gas Supply Portfolio..... 13

IV. Marketer Capacity Paths..... 26

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 1 OF 28

---

**I. Introduction**

**Q. Ms. Culliford, please state your name and business address.**

A. My name is Nancy G. Culliford. 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 Manager of Gas Supply Planning for National Grid USA Service Company, Inc. (Service Company). In this position, I am responsible for managing the resource portfolio of the New England local gas distribution companies that operate as The Narragansett Electric Company (the Company), Boston Gas Company (Boston Gas), and Colonial Gas Company (Colonial Gas), each d/b/a National Grid. For purposes of my 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 Assumption College in 1985 with a Bachelor of Arts degree in Business Management. In 1992, I graduated from Southern New Hampshire University with a Master of Business Administration. From 1986 to 1999, I held various positions at Colonial Gas. In 1998, I was promoted to Manager of Portfolio Planning and Operations, with responsibility for managing all activities associated with Colonial Gas’ gas supply procurement and portfolio execution functions within the Gas Supply Planning

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 2 OF 28

organization. In 1999, I joined Boston Gas as the Manager of Gas Acquisition. In February 2004, I assumed the role of Manager of Gas Resource Management, where I was responsible for managing the short and long term gas supply planning for the former KeySpan Corporation (KeySpan). Following the acquisition of KeySpan Corporation by National Grid plc in 2007, I was named to my current position with the added responsibility of managing the Company's gas resource portfolio in Rhode Island.

**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 Public Utilities Commission (PUC) or any other regulatory commissions?**

A. Yes. I testified before the PUC in last year's Gas Cost Recovery (GCR) filing in Docket No. 4719. I also testified before the PUC in support of the Company's Interim GCR filing submitted on January 26, 2018 in Docket No. 4719 as a result of the increase in actual and forecasted gas prices and the significant increase in gas purchases due to the extremely cold weather in late-2017 and early-2018. In addition, I have testified before the Massachusetts Department of Public Utilities relating to long-range forecasting, gas supply planning, and pipeline capacity agreements.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 3 OF 28

---

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

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

4  
5   **Q.    By whom are you employed and in what capacity?**

6    A.    I am the Director of Gas Supply Planning for the Service Company. In this position, I am  
7       responsible for overseeing the resource portfolio of the New England local gas  
8       distribution companies that operate as the Company, Boston Gas, Colonial Gas, and The  
9       Narragansett Electric Company, each d/b/a National Grid. In addition to the New  
10       England portfolios, I am also responsible for gas supply planning for the resource  
11       portfolios of The Brooklyn Union Gas Company, KeySpan Gas East Corporation, and  
12       Niagara Mohawk Power Corporation, which are all located in New York. For purposes  
13       of my testimony, references to the “Company” relate solely to The Narragansett Electric  
14       Company.

15  
16   **Q.    Please summarize your educational background and your professional experience.**

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

20

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 4 OF 28

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, where 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, where 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.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 5 OF 28

**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 2016 GCR filing in Docket No. 4647. I have also testified numerous times before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission. In addition, I have presented information to the State of New York Department of Public Service.

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

A. Our testimony provides support for the estimated gas costs, assignments of pipeline capacity to Marketers, and other items relating to the Company's proposed 2018-19 GCR factors. In addition, our testimony discusses modifications that the Company has made to its portfolio for the 2018-19 GCR period.

**Q. Are you sponsoring attachments to your testimony?**

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

Attachment NGC/EDA-1	Summary of Projected Gas Costs – <b>CONFIDENTIAL Information</b>
Attachment NGC/EDA-2	Gas Cost Details – <b>CONFIDENTIAL Information</b>
Attachment NGC/EDA-3	NYMEX Strip Comparison
Attachment NGC/EDA-4	Assignment of Pipeline Capacity – <b>CONFIDENTIAL Information</b>
Attachment NGC/EDA-5	FT-2 Operational Parameters
Attachment NGC/EDA-6	FT-2 Storage Variable Costs

---

**II. Projected Gas Costs**

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

**A.** In terms of commodity prices, the proposed GCR factors are based on the following:

(1) the New York Mercantile Exchange (NYMEX) strip as of the close of trading on August 2, 2018, and (2) the difference between the futures contract purchases under the Gas Procurement Incentive Plan as of August 2, 2018 and the August 2, 2018 NYMEX strip. The GCR factors also reflect storage and inventory costs as of August 2, 2018, as well as the projected cost of purchasing gas ratably through the remainder of the injection season, as provided for in the Natural Gas Portfolio Management Plan. Attachment NGC/EDA-1 provides a summary of gas costs by major cost categories. Attachment NGC/EDA-2 shows the details of the calculations, including the cost detail by supply source and the cost impact of financial hedges.

**Q. Overall, what are the NYMEX prices for gas supplies projected to be purchased in the GCR year, and how do they compare to last year's prices?**

**A.** Attachment NGC/EDA-3 is a graph that compares NYMEX pricing from July 31, 2017 utilized in last year's GCR filing to NYMEX pricing from August 2, 2018 used in this current filing. On average, the August 2, 2018 NYMEX strip is \$0.138, or 4.5 percent, lower compared to the July 31, 2017 NYMEX strip during the peak season of November through March. During the off-peak season of April through October, the August 2, 2018 NYMEX strip is on average \$0.183, or 6.5 percent, lower compared to the July 31, 2017

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 7 OF 28

---

1 NYMEX strip. Overall, the August 2, 2018 NYMEX strip is an average of \$0.164, or 5.6  
2 percent lower compared to the July 31, 2017 NYMEX strip.

3  
4 **Q. What design day, design heating season, and design year load is the Company**  
5 **planning for in 2018-19 compared to last year's volumes?**

6 A. To meet design day load requirements for November 2018 through October 2019, the  
7 Company has planned for and contracted for the forecasted volume of 390,227 Dth.  
8 Comparatively, in the Company's previous design day forecast for November 2017  
9 through October 2018 filed in Docket No. 4719, the Company projected design day  
10 volume to be 358,008 Dth. Accordingly, the design day load requirements for 2018-19  
11 have increased by 32,219 Dth, or 9 percent, from last year.

12 To meet design heating season load requirements for November 2018 through October  
13 2019, the Company has planned for and contracted for the forecasted volume of  
14 29,676,936 Dth. Comparatively, in the Company's previous design heating season  
15 forecast for November 2017 through October 2018 filed in Docket No. 4719, the  
16 Company projected design heating season volume to be 26,723,437 Dth. Accordingly,  
17 the design heating season load requirements for 2018-19 have increased by 2,953,499  
18 Dth, or 11 percent, from last year.

19 To meet design year load requirements for November 2018 through October 2019, the  
20 Company has planned for and contracted for the forecasted volume of 41,521,561 Dth.

**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO**  
**AUGUST 31, 2018**  
**PAGE 8 OF 28**

---

1           Comparatively, in the Company's previous design year forecast for November 2017  
2           through October 2018 filed in Docket No. 4719, the Company projected design year  
3           volume to be 37,754,531 Dth. Accordingly, the design year load requirements for  
4           2018-19 have increased by 3,767,030 Dth, or 10 percent, from last year.

5  
6           Thus, based on the increase in the projected design load requirements, the Company had  
7           to procure additional resources this year to meet design customer requirements. A  
8           comparison of the design day, design heating season, and design year load forecasts for  
9           2017-18 and 2018-19 is provided in the table below.

10

11

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 9 OF 28

**2017/18 and 2018/19 Design Forecast Comparison**

	2017/18	2018/19		
<u>Design Day</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Delta</u>	<u>Delta %</u>
Total Design Day (Sales + Transportation)	358,008	390,227	32,219	9.0%
Design Day - Sales	295,421	336,289	40,868	13.8%
Design Day - Transportation	62,587	53,938	(8,649)	-13.8%

	2017/18	2018/19		
<u>Design Heating Season (November - March)</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Delta</u>	<u>Delta %</u>
Total Design Heating Season (Sales + Transportation)	26,723,437	29,676,936	2,953,499	11.1%
Design Heating Season - Sales	21,492,629	24,782,750	3,290,121	15.3%
Design Heating Season - Transportation	5,230,808	4,894,186	(336,622)	-6.4%

	2017/18	2018/19		
<u>Design Year</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Delta</u>	<u>Delta %</u>
Total Design Year (Sales + Transportation)	37,754,531	41,521,561	3,767,030	10.0%
Design Year - Sales	29,325,948	33,532,200	4,206,252	14.3%
Design Year - Transportation	8,428,583	7,989,361	(439,222)	-5.2%

The forecast filed in Docket No. 4719 against this year's forecast.

Volumes include only customers utilizing Company assets.

Volumes are in decatherm (Dth).

**Q. Did the Company perform a cold snap analysis for the 2018-19?**

A. Yes. Following the cold snap experienced in the 2017-18 winter season, the Company reviewed a cold snap scenario, in addition to design day and design year scenarios for the upcoming winter season, as part of its annual portfolio planning process. The cold snap analysis is set forth in the Company's Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27. Through these analyses, the Company

1 determined that it would need to contract for additional resources in the form of  
2 incremental pipeline capacity, citygate delivered purchases, and/or incremental liquefied  
3 natural gas (LNG) resources to meet customer requirements. The additional resources  
4 acquired to meet customer requirements are set forth in Section III (Gas Supply  
5 Portfolio).

6  
7 **Q. How are projected gas costs calculated?**

8 A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT®  
9 model to perform a dispatch optimization of the entire Rhode Island portfolio of gas  
10 supply, pipeline transportation, underground storage, and peaking supplies.  
11 SENDOUT® allows the Company to determine the optimal dispatch of its existing  
12 resources subject to contractual and operating constraints to minimize the cost of supply  
13 over the year. The pricing of various pipeline services is based directly on the pipeline  
14 tariffs and the rates in effect as of August 1, 2018. For purchases at locations other than  
15 the Henry Hub, the model uses the expected basis differential to the Henry Hub prices to  
16 determine the expected difference or “basis.”

17  
18 **Q. How did the Company categorize the projected gas cost components?**

19 A. For the purpose of this filing, gas costs are disaggregated into the following two  
20 components: (1) the Supply Fixed Cost Component, and (2) the Supply Variable Cost  
21 Component. Each component is described below.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 11 OF 28

The Supply Fixed Cost Component includes all fixed costs related to the purchase, storage, or delivery of firm gas, including pipeline and supplier fixed reservation costs and demand charges.

The Supply Variable Cost Component includes all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense 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 2018 through October 2019 is shown in Attachment NGC/EDA-1.

**Q. Please describe Attachment NGC/EDA-2, Pages 1 through 17.**

A. Attachment NGC/EDA-2 shows the supporting detail for gas costs included in the filing for the period November 2018 through October 2019. The first two pages show the optimized, forecasted sendout by supply source under normal weather conditions from the SENDOUT® model, as well as the detailed makeup of supply by pipeline source, storage contract, and peaking facility/contract. The next section, Pages 3 through 6, shows the calculation of the unitized delivered cost for each pipeline path based on the

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 12 OF 28

August 2, 2018 NYMEX strip, including both pipeline variable charges and pipeline fuel losses. Pages 7 through 9 show the calculation of the delivered cost for each path, which is the price multiplied by the quantity. Pages 10 through 14 show the detailed calculation of total fixed costs. The cost details for gas injected into and withdrawn from underground storage are shown on Pages 15 and 16, while all costs associated with LNG injected into and withdrawn from storage are detailed on Page 17. The pricing included in this filing reflects both actual pricing and indicative pricing and terms based on the Company's current contracts with suppliers. Charges for the supply contracts have been redacted in the public version of the filing in order to comply with confidentiality terms in the Company's agreements with its suppliers.

**Q. Please provide an example of how you calculate the delivered cost for a particular gas supply.**

A. In Attachment NGC/EDA-2, Page 3, the second supply source shown is gas purchased on the Tennessee Pipeline in Zone 4. The calculation for November begins with the \$2.857 NYMEX price, which is then adjusted for basis by, in this case, subtracting \$0.243. This reflects the forward basis strip for gas supply in Zone 4 delivered into the Tennessee Pipeline. Next, the price is adjusted to reflect the fuel retention percentage of the pipeline, 1.24 percent, to bring the price to \$2.6468. The adjustment is made by dividing the price by one minus the loss factor, 0.9876. This effectively adjusts the commodity price to incorporate the fact that only 98.76 percent of the supply delivered from the

pipeline in Zone 4 will be delivered to Rhode Island. The pipeline usage fee of \$0.1181 is then added to reflect the cost of transportation on the pipeline, resulting in a delivered cost of \$2.7649 per dekatherm (Dth).

### **III. Gas Supply Portfolio**

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

A. No. As previously described in Docket No. 4719, the Company continues to operate the portfolio similarly to its operation during the 2017/18 GCR period. The Company's Rhode Island 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 Texas Eastern Transmission (Texas Eastern) Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company's citygates on the Algonquin Gas Transmission (Algonquin) pipeline, as well as the Tennessee Gas Pipeline Company, LLC (Tennessee) Zone 4 (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.

**Q. Have there been any changes and/or additions to the Company's transportation 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.

Firm Gas Transportation Agreements (Tennessee and Portland Natural Gas Transmission System)

On November 30, 2017, the Company submitted the following firm gas transportation agreements for review and support by the Division of Public Utilities and Carriers (the Division): (1) two long term gas transportation agreements between National Grid and Tennessee to deliver an additional 44,000 Dth per day to existing into Rhode Island citygates in Cranston and Lincoln (the Tennessee Agreements); and (2) one precedent agreement with Portland Natural Gas Transmission System (Portland) (the Portland Agreement). Collectively, the Tennessee and Portland agreements are necessary for the Company to secure long term access to gas supplies to replace the lost capacity from the cancellation of the Tennessee Northeast Energy Direct (NED) Project and the decommissioning of the Company's Cumberland LNG tank. Each of the firm transportation agreements is described in more detail below.

(1) Tennessee Agreements

The first firm transportation agreement between the Company and Tennessee is for 20,000 Dth per day. The Company's commitment in the NED Project included an incremental 20,000 Dth per day of firm pipeline capacity in order to meet forecasted requirements. No material changes in customer requirements have occurred that would mitigate or eliminate the need for such capacity. This capacity is necessary to ensure that the Company will have adequate pipeline capacity to transport gas supplies and be able to meet forecasted peak day and peak season customer requirements. The capacity has a primary receipt point at the interconnect with ENGIE Gas & LNG LLC (ENGIE) at Everett, Massachusetts for delivery to the Company's citygate in Cranston, Rhode Island. In order to satisfy this incremental need, the Company negotiated a phased-in quantity to more closely coincide with the initial forecasted incremental need of the Company's firm gas customers in Southern Rhode Island. The initial phased-in contract volumes are set forth in the table below.

Effective Date	Nov-2018	Nov-2019	Nov-2023
Maximum Daily Quantity (dt/day)	5,000	10,000	20,000

Given the increase in customer requirements for the upcoming 2018-19 period, [REDACTED]  
[REDACTED]  
[REDACTED] the Company contacted Tennessee to see if it would be feasible to accelerate the phased-in portion of the maximum daily quantity (MDQ) from 5,000 Dth per day to 10,000 Dth per day effective November 1,

**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO**  
**AUGUST 31, 2018**  
**PAGE 16 OF 28**

---

1        2018. Tennessee confirmed that the acceleration would be feasible. Therefore, the MDQ  
2        increases from 5,000 Dth per day to 15,000 Dth per day effective November 1, 2018.

3        Thus, effective November 1, 2018 the Company plans to amend the original agreement to  
4        have 15,000 Dth per day instead of 5,000 Dth per day on this agreement with a receipt  
5        point of Everett.

6  
7        The second firm transportation agreement between the Company and Tennessee  
8        represents a continuation of the existing 24,000 Dth per day of capacity that the Company  
9        originally contracted for in November 2016. After the Company took the Cumberland  
10       LNG tank out of service in the summer of 2016, the Company secured an incremental  
11       24,000 Dth per day of pipeline capacity from Tennessee for the period of November 1,  
12       2016 through October 31, 2017 from Dracut, Massachusetts to its citygate in Lincoln,  
13       Rhode Island. Because such capacity was, at that time, reserved as part of the NED  
14       Project, the Company negotiated the term of the capacity for one year, but maintained a  
15       “right of first refusal” on the capacity for an additional year. The Company exercised its  
16       right of first refusal for the period of November 1, 2017 through October 31, 2018.

17       Tennessee offered the Company to acquire such capacity for a 20-year term beginning  
18       November 1, 2018, with primary receipts allocated between Dracut (14,000 Dth per day)  
19       and Everett (10,000 Dth per day) and primary delivery to the Lincoln citygate. The  
20       Company executed the agreement for a 20-year term effective November 1, 2018.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 17 OF 28

---

1           (2)     Portland Agreement

2           On August 31, 2017, the Company executed a precedent agreement with Portland for the  
3           Portland Xpress Project which, once fully phased in, will allow the Company to supply  
4           29,000 Dth per day of its Dracut receipt point entitlements on Tennessee using supplies  
5           from Dawn, Ontario via transportation agreements with Union Gas, TransCanada, and  
6           Portland. Canadian supplies are brought into the U.S. border at the point of  
7           interconnection between TransCanada and Portland known as East Hereford,  
8           Quebec/Pittsburg, New Hampshire. On April 20, 2018, Portland filed an application with  
9           the Federal Energy Regulatory Commission (FERC) to satisfy the requirements of  
10          Phase I of the Portland Xpress Project and requested approval by September 30, 2018 to  
11          achieve an in-service date of November 1, 2018. Subject to receipt of such approval by  
12          the FERC, effective November 1, 2018 the Company will have firm capacity entitlements  
13          of 11,037 Dth per day on the Union Gas pipeline system from Dawn to Parkway and  
14          10,910 Dth per day on TransCanada from Parkway to East Hereford. The path then  
15          continues from East Hereford to the interconnect with Tennessee at Dracut,  
16          Massachusetts. This supply is delivered to the Company's distribution system using the  
17          Company's existing transportation contracts on the Tennessee pipeline.

18  
19          Tennessee Contract Consolidation

20          The Company has three long-haul contracts with Tennessee in its portfolio with  
21          entitlements located in the Gulf of Mexico: (1) Contract No. 62857 has a MDQ of

**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO**  
**AUGUST 31, 2018**  
**PAGE 18 OF 28**

19,335 Dth per day; (2) Contract No. 1597 has a MDQ of 5,000 Dth per day; and (3) Contract No. 8216 has a MDQ of 5,000 Dth per day. These three contracts will be combined into one contract with a MDQ of 29,335 Dth per day. By consolidating the three agreements into one agreement, the Company has created nomination and scheduling efficiencies within its portfolio, while not losing any firm entitlements. Additionally, the combined agreement will have an end date of October 31, 2024.

Columbia Gas Transmission, LLC (Contract No. 31520)

On February 15, 2018, the Company agreed with Columbia Gas Transmission, LLC (Columbia) to amend the receipt point on Contract No. 31520 from Downingtown, Pennsylvania to Pennsburg, Pennsylvania. In January 2018 the Company ran into an issue purchasing supply at Downingtown, the interconnect between Transcontinental Gas Pipe Line Company, LLC (Transco) and Columbia, due to pressure balancing between the two pipelines. As a result, the Company sought to switch to a more reliable and liquid point at a different receipt on the Columbia system. The Company's analysis of the available receipt points demonstrated that the Pennsburg receipt point would serve as a less-expensive and more liquid trading point than the previous Downingtown point. Accordingly, the Company would no longer be purchasing gas based on the Transco, Zone 6 non-N.Y. index and would now have access to gas based on the less-expensive Texas Eastern M-3 index. The amended contract went into effect on April 1, 2018.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 19 OF 28

**Q. How will the Company supply the Dawn capacity path in Ontario, Canada to Waddington, NY for the 2018-19 year?**

**A.** The Company has a total firm capacity entitlement of 1,025 Dth per day on the Union Gas pipeline system. The capacity path originates at the Dawn Hub in Ontario, Canada and delivers into TransCanada at the Parkway Compressor Station in Ontario. In addition, the Company has firm capacity entitlements of 1,012 Dth per day on the TransCanada pipeline system. The capacity path originates at the interconnection with Union Gas at Parkway and delivers into Iroquois Gas Transmission System (Iroquois) at Waddington, New York. This supply is delivered to the Company's distribution system using the Company's existing transportation contracts on Iroquois and the Tennessee.

On August 7, 2018, the Company issued a request for proposal (RFP) for an Asset Management and Gas Supply Agreement (AMA), similar to the RFP issued last year, for a term of one year effective November 1, 2018. The RFP requested a MDQ of 1,025 Dth per day with a swing component for the months of November 2018 and March 2019 and a baseload volume for the months of December 2018, January 2019, and February 2019. These supplies will be transported on the Company's Iroquois and Tennessee pipeline transportation capacity to the Company's citygates. 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 the customers. On August 17, 2018, the

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 20 OF 28

Company selected an offer for asset management services commensurate with the foregoing information and is presently negotiating a transaction confirmation to memorialize the trade.

**Q. How will the Company supply the new Portland capacity path from Dawn for 2018-19?**

A. On August 7, 2018, the Company issued a RFP for an AMA to manage the Canadian assets associated with this path for a term of one year effective November 1, 2018. The RFP requested a MDQ of 11,037 Dth per day with a daily call for the months of November 2018 through April 2019. The gas will be delivered into the Portland pipeline at East Hereford and will be transported on both the Portland and Tennessee pipelines to the Company's citygates; the Company will be managing the Portland and Tennessee capacity to which the asset manager will deliver. 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 credited to the customers. On August 17, 2018, the Company selected an offer for asset management services commensurate with the foregoing information and is presently negotiating a transaction confirmation to memorialize the trade.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 21 OF 28

**Q. How will the Company supply the Dracut capacity path for 2018-19?**

A. On July 26, 2018, the Company issued a RFP to purchase supply at Dracut, Massachusetts for a term of four months, December 2018 through March 2019. Utilizing the SENDOUT® model, the Company determined the appropriate resource mix and established the required volume for the term in the event of design weather conditions. The RFP requested a MDQ of 17,700 Dth per day and a maximum seasonal quantity (MSQ) of 531,000 Dth. The Company will transport the volumes from the primary Dracut receipt point on the Tennessee contracts to the Company's citygates. On August 14, 2018, the Company selected an offer for services commensurate with the foregoing information and is presently negotiating a transaction confirmation to memorialize the trade.

**Q. How will the Company supply the initial Tennessee capacity paths with a total MDQ of 15,000 Dth from Everett, Massachusetts for 2018-19?**

A. On April 3, 2018, the Company issued a RFP for a long term supply deal to limit the Company's exposure off the Tennessee pipeline served by receipts out of Everett. The RFP called for a 10-year term beginning December 1, 2018. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

1 [REDACTED] The table below sets forth the MDQ and MSQ of the awarded long  
2 term supply deal.

Delivery Period	MDQ (Dth)	MSQ (Dth)
December 1, 2018-March 31, 2019	15,000	321,000
December 1, 2019-March 31, 2020	20,000	632,000
December 1, 2020-March 31, 2021	20,000	651,000
December 1, 2021-March 31, 2022	20,000	651,000

3  
4  
5 **Q. Did the Company procure any citygate delivered supplies for 2018-19?**

6 A. Yes. On July 26, 2018, the Company issued a RFP for a citygate service from December  
7 1, 2018 through March 31, 2019 seeking a MDQ of 33,000 Dth and a MSQ of 1,118,000  
8 Dth. As part of the RFP, the Company requested that each bidder demonstrate that it has  
9 primary firm capacity to each delivery point(s) at which the bidder is offering firm  
10 service and/or provide a written explanation of the priority of service it will utilize to  
11 serve a Buyer's rights under a Transaction Confirmation resulting from this RFP. The  
12 Company accepted a bid with a MDQ of up to 14,100 Dth per day with an annual  
13 contract quantity of 507,000 Dth and is presently negotiating a transaction confirmation  
14 to memorialize the trade.

15  
16 **Q. How is the Company going to supply the accelerated MDQ of 10,000 Dth per day on  
17 the Tennessee pipeline from Everett, Massachusetts for 2018-19?**

18 A. As referenced above, the Company [REDACTED]  
19 [REDACTED] sought to accelerate the phased-in MDQ on the

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 23 OF 28

---

1 Tennessee pipeline capacity. Also, in response to the Company's July 26, 2018 RFP for  
2 supplies at Dracut, Massachusetts, the Company received a non-conforming offer for  
3 supplies at the receipt point of Everett. When Tennessee approved the acceleration of  
4 10,000 Dth per day, the Company negotiated with the entity that submitted the  
5 nonconforming bid for up to 10,000 Dth per day and an annual contract quantity of  
6 500,000 Dth. The Company will transport the volumes on the Tennessee contract on a  
7 primary basis from Everett to Cranston, Rhode Island. The Company is presently  
8 negotiating a transaction confirmation to memorialize the trade.

9  
10 **Q. Has the Company arranged for firm liquid service for LNG needed during the**  
11 **2018/19 peak season?**

12 A. The Company is currently in the process of evaluating offers to meet an annual contract  
13 quantity of 300,000 Dth with eight trucks per day.

14  
15 **Q. Have the Company and the Division addressed the costs associated with leasing**  
16 **third-party portable LNG equipment and services, as requested by the PUC in last**  
17 **year's GCR proceeding?**

18 A. Yes. The Company and the Division have addressed and came to a resolution on the  
19 costs associated with leasing third-party portable LNG equipment and services. The  
20 Company will report the parties' findings to the PUC in early-September 2018.

21

**Q. What is the status of the Company's long term solution to replace the supply lost as a result of the decommissioning of the Cumberland LNG tank?**

A. As of August 31, 2018, the Company is working on contract terms for a long term solution to address the capacity needs in Northern Rhode Island. The Company anticipates having the pricing finalized and a precedent agreement in place by November 30, 2018, with an estimated in-service date of late-2019. As such, the costs to address the long term solution to replace supply lost as a result of the decommissioning of the Cumberland LNG tank are expected to be included in next year's GCR filing.

**Q. Please provide any status updates to the Company's pending precedent agreements with Millennium Pipeline Company LLC (Millennium); National Grid LNG, LLC (NGLNG); and Northeast Energy Center, LLC (Northeast Energy).**

A. Updates to the Company's pending precedent agreements with Millennium, NGLNG, and Northeast Energy are as follows:

Millennium Eastern System Upgrade Project (Eastern System Upgrade)

The Eastern System Upgrade will provide the Company with the opportunity to directly secure a cost effective domestically produced source of supply to feed half of the Company's entitlement on its Algonquin Incremental Market (AIM) capacity. The Eastern System Upgrade was originally intended to be in service for the 2017-18 winter season. However, unprecedented opposition at both at the state and federal levels, as

**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO**  
**AUGUST 31, 2018**  
**PAGE 25 OF 28**

---

1 well as a lack of quorum at the FERC during the first seven months of 2017, resulted in a  
2 delay of the Eastern System Upgrade receiving all necessary permits and authorizations  
3 to commence construction and service. Millennium has now commenced construction on  
4 the project, which includes the addition of horsepower at the existing Hancock  
5 Compressor Station; the new greenfield compressor station in Highland, New York;  
6 meter station work at the Algonquin interconnect at Ramapo, New York; and the various  
7 sections of the 7.8 mile pipeline looping. Millennium anticipates that the project  
8 facilities will be in-service in the peak season of 2018/19.

9  
10 NGLNG

11 The Company previously entered into a precedent agreement for a term of 20 years for  
12 liquefaction services at NGLNG's currently-existing storage facilities located in  
13 Providence, Rhode Island. On June 25, 2018, the FERC issued its Environmental  
14 Assessment of the NGLNG project. Accordingly, NGLNG is expected to receive its  
15 certificate of public convenience and necessity on or before September 23, 2018, which  
16 would allow for the facilities to be in service for the 2021 refill season. The Company  
17 will be able to utilize its existing Algonquin capacity to transport volumes to the NGLNG  
18 plant in Providence for liquefaction during the off-peak period.

1        Northeast Energy

2        The Company previously entered into a precedent agreement for up to 2,616 Dth per day  
3        for a term of 15 years for liquefaction services with Northeast Energy. The Northeast  
4        Energy project will be located in central Massachusetts and has an intended in-service  
5        date of April 1, 2020. At this time, Northeast Energy has not filed for regulatory  
6        approval or authorization to construct or operate the facilities necessary to provide the  
7        contracted for liquefaction services.

8  
9    **IV.    Marketer Capacity Paths**

10   **Q.    What transportation paths will be available for assignment to Marketers?**

11   A.    Attachment NGC/EDA-4, Page 1, shows the paths and corresponding quantities available  
12        for assignment to Marketers. In total, the Company has made available 35,258 Dth of  
13        capacity per day on seven different pipeline paths. There is one change made to these  
14        capacity paths from last year. As explained earlier in our testimony, the Company  
15        changed receipt points on Columbia, switching from the Downingtown receipt point to  
16        the Pennsburg receipt point. As a result of this change, the Company made a  
17        corresponding change to the transportation path on Columbia on which the Company  
18        releases. So, for example, if a Marketer elected capacity to be released from the  
19        Columbia path, the Marketer will receive transportation from Pennsburg instead of from  
20        Downingtown.

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 27 OF 28

**Q. What is the surcharge/credit calculation for each assigned pipeline path?**

A. The first step in calculating the adjustment charge for each path is calculating the system average cost. The derivation of the weighted average pipeline path cost of \$0.7693 per Dth is shown in Attachment NGC/EDA-4, Page 11. This cost is equal to the sum of the 100 percent load factor fixed cost unit value; the system-average unit variable cost, including basis differential; and one year of the Marketer reconciliation adjustment represented as a 100 percent load factor per-unit cost. The 100 percent load factor fixed cost unit value is [REDACTED] per Dth. The system average pipeline unit variable value is a negative [REDACTED] per Dth. The sum of these components results in a weighted average pipeline cost of \$0.7713 per Dth. The 100 percent load factor per-unit value of \$0.0020 for the Marketer reconciliation adjustment is then credited to get the total weighted average pipeline cost of \$0.7693 per Dth.

**Q. How are the delivered costs for each path released to Marketers developed in Attachment NGC/EDA-4?**

A. The calculations for the delivered cost for each path are similar to those described for the system-average. For illustration, the calculation for the first path (Tennessee Zone 1, shown on Attachment NGC/EDA-4, Page 6) is comprised of a single contract originating in Zone 1 and terminating in Zone 6. Total fixed costs of \$2,442,074 and total variable costs of \$10,695,927 are shown in the far right column on Page 6 of Attachment NGC/EDA-4. Commodity gas costs of \$9,567,118 are subtracted from the total variable

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
PAGE 28 OF 28

---

1 costs to arrive at the non-gas variable costs, which include pipeline variable charges and  
2 any basis differential associated with the path. The cost of the path equals the sum of the  
3 fixed unit cost of \$0.7043 per Dth at 100 percent load factor, plus the non-gas variable  
4 unit cost of \$0.3255 per Dth, for a total path cost of \$1.0298 per Dth. The unit cost of  
5 \$1.0298 per Dth represents the direct costs incurred by the Marketer, which are paid  
6 directly to the pipeline by the Marketer. Because this cost is \$0.2605 per Dth greater than  
7 the system average, Marketers electing this path would be credited \$0.2605 per Dth per  
8 day on their monthly invoice from the Company. A summary of the individual path costs  
9 and associated credits or surcharges, for which approval is sought, is shown on Page 1 of  
10 Attachment NGC/EDA-4.

11  
12 **Q. Does this conclude your testimony?**

13 **A. Yes.**

**Joint Attachments of  
Culliford & Arango**

NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESSES: NANCY G. CULLIFORD AND ELIZABETH D. ARANGIO  
AUGUST 31, 2018  
ATTACHMENTS

---

Attachments of Nancy G. Culliford and Elizabeth D. Arangio

Attachment NGC/EDA-1	Summary of Projected Gas Costs – <b>CONFIDENTIAL Information</b>
Attachment NGC/EDA-2	Gas Cost Details - <b>CONFIDENTIAL Information</b>
Attachment NGC/EDA-3	NYMEX Strip Comparison
Attachment NGC/EDA-4	Assignment of Pipeline Capacity – <b>CONFIDENTIAL Information</b>
Attachment NGC/EDA-5	FT-2 Operational Parameters
Attachment NGC/EDA-6	FT-2 Storage Variable Costs



## 08/02/2018 NYMEX

[illegible]



National Grid 2018 Estimated GCR Normal Weather Scenario	Natural Gas Supply VS. Requirements												Units: DTH	
	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	OCT 2019	TOTAL	
Forecast Demand	2,688,486	4,596,563	5,536,758	4,759,103	3,954,964	2,142,275	1,253,992	800,356	629,551	635,180	803,591	1,631,539	29,432,358	
RI Sales Demand GCR														
Storage Injections														
TENNESSEE FSMA 501	0	0	0	0	0	0	86,478	13,157	86,478	86,478	86,478	86,478	445,545	
DOMINION GSS 300170	0	0	0	0	0	0	59,184	59,184	59,184	59,184	59,184	59,184	355,103	
DOMINION GSS 300168	0	0	0	0	0	7,627	22,007	22,007	22,007	21,151	21,856	21,856	138,510	
DOMINION GSS 300171	0	0	0	0	0	22,743	26,973	26,973	26,973	26,783	25,919	26,783	183,150	
DOMINION GSSTE 600045	0	0	0	0	0	0	8,350	36,903	0	0	168,457	168,457	382,166	
TETCO FSS-1 400515	0	0	0	0	0	6,392	8,091	8,091	8,091	8,091	8,091	8,091	54,941	
TETCO SS-1 400221	0	0	0	0	0	134,078	169,719	169,719	169,719	169,719	169,719	169,719	1,152,392	
TETCO SS-1 400185	0	0	0	0	0	5,867	7,427	7,427	7,427	7,427	7,427	7,427	50,430	
DOMINION GSS 300169	0	0	0	0	0	24,828	29,443	29,443	29,443	29,234	28,291	29,234	199,917	
COLUMBIA FSS 9630	0	0	0	0	0	0	40,791	34,673	40,791	40,791	26,514	14,277	197,838	
TENNESSEE 62918	0	0	0	0	0	23,700	30,000	30,000	30,000	30,000	30,000	30,000	203,700	
Total Storage Injections	0	0	0	0	0	225,236	488,464	437,577	480,114	479,564	631,231	621,506	3,363,692	
LNG PROVIDENCE	0	97,399	0	47,172	57,063	150,000	155,000	133,546	20,067	0	90,000	11,011	761,257	
LNG EXETER	0	53,519	0	12,665	32,183	30,000	31,000	46,454	12,000	0	90,000	6,175	313,996	
Total LNG Injections	0	150,918	0	59,837	89,246	180,000	186,000	180,000	32,067	0	180,000	17,187	1,075,253	
Total Injections	0	150,918	0	59,837	89,246	405,236	674,464	617,577	512,180	479,564	811,231	638,693	4,438,946	
<b>Delivered Firm Sales Supply</b>														
Sources of Supply	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total	
TENNESSEE ZONE 4 CXN	348,000	359,600	359,600	324,800	359,600	195,557	305,798	170,587	211,916	212,215	243,612	359,600	3,450,885	
TENNESSEE ZONE 4	223,511	418,267	536,092	485,968	296,481	0	0	0	0	0	0	20,439	1,980,757	
TENNESSEE NIAGARA	31,409	31,061	18,275	15,344	29,853	32,010	33,077	32,010	33,077	33,077	32,010	33,077	354,280	
TENNESSEE DRACUT	0	8,970	38,875	16,491	0	0	0	0	0	0	0	0	64,336	
TETCO M2	770,348	796,550	796,367	719,620	798,005	780,725	804,428	688,926	512,145	516,124	407,905	802,427	8,393,569	
TETCO M3	524,853	84,328	183,132	143,109	79,927	608,684	192,483	30,000	30,424	30,943	442,884	618,265	2,969,031	
COLUMBIA MAUMEE	232,075	847,977	861,084	774,484	793,538	192,228	15,388	0	39,168	37,545	0	33,851	3,827,337	
COLUMBIA BROADRUN	90,317	308,107	308,107	278,403	278,403	53,342	0	0	1,623	3,246	0	0	1,321,549	
COLUMBIA EAGLE/PENNSBURG	21,224	76,385	148,816	125,952	53,941	4,052	61,941	34,673	0	0	26,514	59,645	613,142	
DOMINION SOUTH POINT	0	0	15,730	0	0	0	0	0	0	0	0	0	15,730	
TRANSCO LEIDY	2,160	35,634	38,025	34,356	24,179	2,160	1,794	2,160	2,232	2,232	2,160	2,232	149,324	
TETCO LEIDY	0	14,874	206	14,348	6,377	0	0	0	0	0	0	0	35,804	
TETCO to B&W SCT	0	57,671	62,970	56,673	25,188	0	0	0	0	0	0	0	202,502	
ALGONQUIN - AIM	34,114	45,151	86,509	78,963	28,461	12,470	1,217	0	0	0	0	4,693	291,578	
MILLENNIUM	267,432	275,965	273,364	249,379	276,098	263,958	256,141	232,945	230,893	231,175	233,105	264,411	3,054,867	
DAWN TO WASHINGTON	3,006	31,026	30,978	27,997	11,007	30,000	31,000	30,000	31,000	31,000	30,000	31,000	318,014	
DAWN TO EAST HEREFORD	18,480	171,016	268,264	225,560	96,910	113,808	22,002	0	0	0	0	6,219	922,258	
ENGIE - AGT	0	88,780	164,148	193,935	27,598	0	0	0	0	0	0	0	474,461	
ENGIE - EVERETT	0	0	0	0	0	0	0	0	0	0	0	0	0	
ENGIE LNG Refill - Winter	0	150,918	0	59,836	89,246	0	186,000	180,000	32,067	0	180,000	17,187	300,000	
ENGIE LNG Refill - Summer	0	0	0	0	0	180,000	186,000	180,000	32,067	0	180,000	17,187	775,253	
PORTABLE LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	
Non LNG Liquid take	2,566,928	3,651,361	4,190,540	3,765,383	3,185,565	2,288,993	1,725,270	1,221,301	1,092,478	1,097,557	1,418,190	2,235,858	28,439,424	
LNG Liquid take	0	150,918	0	59,836	89,246	180,000	186,000	180,000	32,067	0	180,000	17,187	1,075,253	
Total take	2,566,928	3,802,279	4,190,540	3,825,219	3,274,811	2,468,993	1,911,270	1,401,301	1,124,545	1,097,557	1,598,190	2,253,045	29,514,678	

Natural Gas Supply VS. Requirements														Units: DTH	
2018 Estimated GCR															
Normal Weather Scenario															
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL		
Storage Withdrawals															
TENNESSEE FSMA 501	16,542	141,779	99,741	36,473	145,486	0	0	0	0	0	0	0	440,020		
DOMINION GSS 300170	0	92,131	112,160	104,979	34,591	0	0	0	0	0	0	0	343,861		
DOMINION GSS 300168	5,535	33,447	35,974	35,919	25,918	0	0	0	0	0	0	0	136,793		
DOMINION GSS 300171	0	29,600	68,215	58,699	22,353	0	0	0	0	0	0	0	178,867		
DOMINION GSSTE 600045	61,743	63,692	63,692	57,551	63,717	61,886	0	0	0	0	0	0	372,281		
TETCO FSS-1 400515	0	13,664	13,664	13,669	12,029	0	0	0	0	0	0	0	53,026		
TETCO SS-1 400221	0	288,307	288,307	288,776	254,123	0	0	0	0	0	0	0	1,119,512		
TETCO SS-1 400185	0	12,617	12,617	12,637	11,121	0	0	0	0	0	0	0	48,991		
DOMINION GSS 300169	0	49,335	53,973	51,275	39,356	0	0	0	0	0	0	0	193,938		
COLUMBIA FSS 9630	4,982	36,454	69,466	55,595	26,413	0	0	0	0	0	0	0	192,909		
TENNESSEE 62918	0	29,251	48,733	90,533	32,657	0	0	0	0	0	0	0	201,174		
LNG PROVIDENCE	26,781	90,785	352,780	145,445	69,452	10,656	11,011	10,656	11,011	11,011	10,656	11,011	761,257		
LNG EXETER	5,976	64,141	126,898	42,169	32,183	5,976	6,175	5,976	6,175	6,175	5,976	6,175	313,996		
Total Withdrawal Delivered	121,558	945,202	1,346,218	993,720	769,399	78,519	17,187	16,632	17,187	17,187	16,632	17,187	4,356,626		
Total Storage Withdrawal	88,801	790,276	866,540	806,106	667,763	61,886	0	0	0	0	0	0	3,281,373		
Total Peaking Withdrawal	32,757	154,926	479,678	187,614	101,636	16,632	17,187	16,632	17,187	17,187	16,632	17,187	1,075,253		
Total Supply	2,688,486	4,596,563	5,536,758	4,759,103	3,954,964	2,367,511	1,742,456	1,237,933	1,109,665	1,114,744	1,434,822	2,253,045	32,796,050		
Storage Withdrawals at Storage Facility															
TENNESSEE FSMA 501	16,749	143,559	100,994	36,931	147,312	0	0	0	0	0	0	0	445,545		
DOMINION GSS 300170	0	95,143	115,827	108,411	35,722	0	0	0	0	0	0	0	355,103		
DOMINION GSS 300168	5,604	33,867	36,426	36,370	26,243	0	0	0	0	0	0	0	138,510		
DOMINION GSS 300171	0	30,314	69,861	60,091	22,883	0	0	0	0	0	0	0	183,150		
DOMINION GSSTE 600045	63,343	65,454	65,454	59,120	65,454	63,343	0	0	0	0	0	0	382,166		
TETCO FSS-1 400515	0	14,160	14,160	14,160	12,461	0	0	0	0	0	0	0	54,941		
TETCO SS-1 400221	0	297,008	297,008	297,008	261,367	0	0	0	0	0	0	0	1,152,392		
TETCO SS-1 400185	0	12,998	12,998	12,998	11,438	0	0	0	0	0	0	0	50,430		
DOMINION GSS 300169	0	50,866	55,647	52,844	40,561	0	0	0	0	0	0	0	199,917		
COLUMBIA FSS 9630	5,090	37,396	71,260	57,008	27,084	0	0	0	0	0	0	0	197,838		
TENNESSEE 62918	0	29,618	49,345	91,670	33,068	0	0	0	0	0	0	0	203,700		
	90,786	810,383	888,979	826,611	683,592	63,343	0	0	0	0	0	0	3,363,693		

National Grid 2018 Estimated GCR Normal Weather Scenario		Natural Gas Supply V/S. Requirements												Units: DTH	
		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL	
08/02/2018 NYMEX		\$2.857	\$2.958	\$3.043	\$3.006	\$2.903	\$2.605	\$2.578	\$2.608	\$2.642	\$2.648	\$2.629	\$2.645		
TENNESSEE ZONE 4 CONNEXION															
Basis		(\$0.243)	(\$0.245)	(\$0.246)	(\$0.245)	(\$0.244)	(\$0.127)	(\$0.210)	(\$0.228)	(\$0.265)	(\$0.272)	(\$0.369)	(\$0.347)		
Usage to Zn 6		\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131		
Fuel to Zn 6		1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%		
Total Delivered		\$2.6599	\$2.7602	\$2.8452	\$2.8088	\$2.7055	\$2.5222	\$2.4108	\$2.4230	\$2.4199	\$2.4189	\$2.3015	\$2.3400		
TENNESSEE ZONE 4															
Basis		(\$0.243)	(\$0.245)	(\$0.246)	(\$0.245)	(\$0.244)	(\$0.127)	(\$0.210)	(\$0.228)	(\$0.265)	(\$0.272)	(\$0.369)	(\$0.347)		
Usage to Zn 6		\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181		
Fuel to Zn 6		1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%		
Total Delivered		\$2.7649	\$2.8652	\$2.9502	\$2.9138	\$2.8105	\$2.6272	\$2.5158	\$2.5280	\$2.5249	\$2.5239	\$2.4065	\$2.4450		
TENNESSEE NIAGARA															
Basis		(\$0.275)	(\$0.229)	(\$0.135)	(\$0.121)	(\$0.236)	(\$0.447)	(\$0.536)	(\$0.519)	(\$0.565)	(\$0.595)	(\$0.584)	(\$0.599)		
Tenn usage		\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891		
Tenn Fuel		0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%		
Total Delivered		\$2.6948	\$2.8432	\$3.0238	\$3.0006	\$2.7806	\$2.2669	\$2.1499	\$2.1973	\$2.1852	\$2.1610	\$2.1529	\$2.1539		
TENNESSEE DRACUT															
Basis		\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363		
Usage		0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%		
Fuel															
Total Delivered															
TETCO M2															
Basis		(\$0.365)	(\$0.350)	(\$0.290)	(\$0.285)	(\$0.327)	(\$0.383)	(\$0.480)	(\$0.495)	(\$0.515)	(\$0.502)	(\$0.597)	(\$0.587)		
Usage on Tetco		\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512		
Usage on AGT		\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125		
Fuel on Tetco		1.82%	2.40%	2.40%	2.40%	2.40%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%		
Fuel on AGT		0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%		
Total Delivered		\$2.6196	\$2.7656	\$2.9158	\$2.8814	\$2.7313	\$2.3427	\$2.2156	\$2.2310	\$2.2453	\$2.2648	\$2.1479	\$2.1746		

[illegible]

Natural Gas Supply v/s. Requirements										Units: DTH	

\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363
0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363
0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%

Natural Gas Supply V.S. Requirements												Units: DTH	
National Grid 2018 Estimated GCR Normal Weather Scenario	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
<b>Total Delivered to the City Gate Gas Supply Costs</b>													
<b>TENNESSEE ZONE 4 CONNEXION</b>													
Delivered MMBtu	348,000	359,600	359,600	324,800	359,600	195,557	305,798	170,587	211,916	212,215	243,612	359,600	
Delivered Price	\$2,6599	\$2,7602	\$2,8452	\$2,8088	\$2,7055	\$2,5222	\$2,4108	\$2,4230	\$2,4199	\$2,4189	\$2,3015	\$2,3400	
Total Delivered Cost	\$925,652	\$992,555	\$1,023,140	\$912,287	\$972,893	\$493,237	\$737,227	\$413,329	\$512,824	\$513,334	\$560,667	\$841,447	
<b>TENNESSEE ZONE 4</b>													
Delivered MMBtu	223,511	418,267	536,092	485,968	296,481	0	0	0	0	0	0	20,439	
Delivered Price	\$2,7649	\$2,8652	\$2,9502	\$2,9138	\$2,8105	\$2,6272	\$2,5158	\$2,5280	\$2,5249	\$2,5239	\$2,4065	\$2,4450	
Total Delivered Cost	\$617,991	\$1,198,403	\$1,581,587	\$1,415,997	\$833,254	\$0	\$0	\$0	\$0	\$0	\$0	\$49,971	
<b>TENNESSEE NIAGARA</b>													
Delivered MMBtu	31,409	31,061	18,275	15,344	29,853	32,010	33,077	32,010	33,077	33,077	32,010	33,077	
Delivered Price	\$2,6948	\$2,8432	\$3,0238	\$3,0006	\$2,7806	\$2,2669	\$2,1499	\$2,1973	\$2,1852	\$2,1610	\$2,1529	\$2,1539	
Total Delivered Cost	\$84,641	\$88,311	\$55,260	\$46,041	\$83,009	\$72,564	\$71,111	\$70,335	\$72,279	\$71,478	\$68,914	\$71,244	
<b>TENNESSEE DRACUT</b>													
Delivered MMBtu	0	8,970	38,875	16,491	0	0	0	0	0	0	0	0	
Delivered Price													
Total Delivered Cost													
<b>TETCO M2</b>													
Delivered MMBtu	770,348	796,550	796,367	719,620	798,005	780,725	804,428	688,926	512,145	516,124	407,905	802,427	
Delivered Price	\$2,6196	\$2,7656	\$2,9158	\$2,8814	\$2,7313	\$2,3427	\$2,2156	\$2,2310	\$2,2453	\$2,2648	\$2,1479	\$2,1746	
Total Delivered Cost	\$2,018,021	\$2,202,910	\$2,322,008	\$2,073,547	\$2,179,606	\$1,829,032	\$1,782,268	\$1,536,963	\$1,149,926	\$1,168,915	\$876,134	\$1,744,920	
<b>TETCO M3</b>													
Delivered MMBtu	524,853	84,328	183,132	143,109	79,927	608,684	192,483	30,000	30,424	30,943	442,884	618,265	
Delivered Price	\$2,7179	\$3,5083	\$5,7980	\$5,6572	\$3,1633	\$2,4289	\$2,2940	\$2,3011	\$2,3423	\$2,3363	\$2,1460	\$2,2155	
Total Delivered Cost	\$1,426,496	\$295,843	\$1,061,795	\$809,599	\$252,829	\$1,478,451	\$441,559	\$69,032	\$71,263	\$72,292	\$950,432	\$1,369,754	
<b>COLUMBIA MAUMEE</b>													
Delivered MMBtu	232,075	847,977	861,084	774,484	793,538	192,228	15,388	0	39,168	37,545	0	33,851	
Delivered Price	\$2,7444	\$2,8499	\$2,9288	\$2,8897	\$2,7359	\$2,4522	\$2,3705	\$2,3684	\$2,3286	\$2,2969	\$2,2540	\$2,2857	
Total Delivered Cost	\$636,915	\$2,416,615	\$2,521,984	\$2,238,050	\$2,171,054	\$471,387	\$36,476	\$0	\$91,207	\$86,238	\$0	\$77,372	
<b>COLUMBIA BROADRUN</b>													
Delivered MMBtu	90,317	308,107	308,107	278,403	278,403	53,342	0	0	1,623	3,246	0	0	
Delivered Price	\$2,7444	\$2,8499	\$2,9288	\$2,8897	\$2,7359	\$2,4522	\$2,3705	\$2,3684	\$2,3286	\$2,2969	\$2,2540	\$2,2857	
Total Delivered Cost	\$247,869	\$878,062	\$902,399	\$804,509	\$761,687	\$130,808	\$0	\$0	\$3,780	\$7,457	\$0	\$0	

National Grid		Units: DTH											
2018 Estimated GCR		Natural Gas Supply V.S. Requirements											
Normal Weather Scenario		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
													TOTAL
<b>COLUMBIA EAGLE/PENNSBURG</b>													
Delivered MMBtu		21,224	76,385	148,816	125,952	53,941	4,052	61,941	34,673	0	0	26,514	59,645
Delivered Price		\$2,7782	\$3,5803	\$5,9038	\$5,7609	\$3,2302	\$2,4849	\$2,3480	\$2,3552	\$2,3971	\$2,3909	\$2,1978	\$2,2683
Total Delivered Cost		\$58,963	\$273,476	\$878,575	\$725,595	\$174,239	\$10,068	\$145,439	\$81,660	\$0	\$0	\$58,274	\$135,294
<b>DOMINION SOUTH POINT</b>													
Delivered MMBtu		0	0	15,730	0	0	0	0	0	0	0	0	0
Delivered Price		\$2,8376	\$2,9557	\$3,0466	\$3,0099	\$2,9055	\$2,5827	\$2,4693	\$2,4766	\$2,4776	\$2,4766	\$2,3580	\$2,3954
Total Delivered Cost		\$0	\$0	\$47,924	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>TRANSCO LEIDY</b>													
Delivered MMBtu		2,160	35,634	38,025	34,356	24,179	2,160	1,794	2,160	2,232	2,232	2,160	2,232
Delivered Price		\$2,7487	\$2,8585	\$2,8971	\$2,8585	\$2,7619	\$2,4683	\$2,3275	\$2,3114	\$2,3417	\$2,3296	\$2,2293	\$2,2830
Total Delivered Cost		\$5,937	\$101,861	\$110,164	\$98,207	\$66,781	\$5,331	\$4,176	\$4,993	\$5,227	\$5,200	\$4,815	\$5,096
<b>TETCO LEIDY</b>													
Delivered MMBtu		0	14,874	206	14,348	6,377	0	0	0	0	0	0	0
Delivered Price		\$2,8778	\$2,9029	\$3,0606	\$2,9796	\$2,8731	\$2,6218	\$2,4046	\$2,4872	\$2,4535	\$2,4974	\$2,3097	\$2,3903
Total Delivered Cost		\$0	\$43,176	\$629	\$42,752	\$18,322	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>TETCO to B&amp;W SCT</b>													
Delivered MMBtu		0	57,671	62,970	56,673	25,188	0	0	0	0	0	0	0
Delivered Price		\$3,1269	\$3,2740	\$3,4242	\$3,3898	\$3,2397	\$2,8500	\$2,7229	\$2,7382	\$2,7526	\$2,7721	\$2,6552	\$2,6818
Total Delivered Cost		\$0	\$188,815	\$215,622	\$192,109	\$81,601	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>ALGONQUIN - AIM</b>													
Delivered MMBtu		34,114	45,151	86,509	78,963	28,481	12,470	1,217	0	0	0	0	4,693
Delivered Price		\$2,7412	\$3,5914	\$5,9430	\$5,7785	\$3,2260	\$2,4485	\$2,3119	\$2,3190	\$2,3608	\$2,3547	\$2,1620	\$2,2324
Total Delivered Cost		\$93,512	\$162,156	\$514,119	\$456,291	\$91,816	\$30,533	\$2,815	\$0	\$0	\$0	\$0	\$10,477
<b>MILLENNIUM</b>													
Delivered MMBtu		267,432	275,965	273,364	249,379	276,098	263,958	256,141	232,945	230,893	231,175	233,105	264,411
Delivered Price		\$2,5454	\$2,6971	\$2,7336	\$2,6847	\$2,5879	\$2,2663	\$2,1258	\$2,1053	\$2,1402	\$2,1258	\$2,0243	\$2,0817
Total Delivered Cost		\$680,708	\$744,293	\$747,271	\$669,498	\$714,516	\$598,220	\$544,510	\$490,420	\$494,152	\$491,436	\$471,867	\$550,427
<b>DAWN TO WADDINGTON</b>													
Delivered MMBtu		3,006	31,026	30,978	27,997	11,007	30,000	31,000	30,000	31,000	31,000	30,000	31,000
Delivered Price		\$3,0662	\$3,2226	\$3,4022	\$3,4089	\$3,1513	\$2,1870	\$2,1102	\$2,2425	\$2,2759	\$2,2557	\$2,1102	\$2,2516
Total Delivered Cost		\$9,217	\$99,984	\$105,394	\$95,437	\$34,686	\$65,609	\$65,416	\$67,276	\$70,552	\$69,925	\$63,306	\$69,800

Natural Gas Supply VS. Requirements												Units: DTH	
2018 Estimated GCR Normal Weather Scenario													
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
DAWN TO EAST HEREFORD													
Delivered MMBtu	18,480	171,016	268,264	225,560	96,910	113,808	22,002	0	0	0	0	0	6,219
Delivered Price	\$2,9829	\$3,1379	\$3,3159	\$3,3225	\$3,0672	\$2,5464	\$2,4250	\$2,4705	\$2,4520	\$2,4477	\$2,4212	\$0	\$2,4243
Total Delivered Cost	\$55,124	\$536,625	\$889,534	\$749,413	\$297,243	\$289,798	\$53,355	\$0	\$0	\$0	\$0	\$0	\$15,077
ENGINE - AGT													
Delivered MMBtu	0	88,780	164,148	193,935	27,598	0	0	0	0	0	0	0	0
Delivered Price													
Total Delivered Cost													
ENGINE - EVERETT													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	0
Delivered Price													
Total Delivered Cost													
Financial Hedges as of August 02, 2018													
Quantity	1,682,500	2,537,000	2,820,000	2,514,000	2,084,000	1,267,650	976,386	617,969	400,217	389,076	457,796	711,198	16,457,791
Average Price	\$2,905	\$3,048	\$3,167	\$3,157	\$3,061	\$2,691	\$2,676	\$2,697	\$2,702	\$2,732	\$2,730	\$2,752	
08/02/2018 NYMEX	\$2,857	\$2,958	\$3,043	\$3,006	\$2,903	\$2,605	\$2,578	\$2,608	\$2,642	\$2,648	\$2,629	\$2,645	
NYMEX Hedges	\$80,627	\$227,416	\$350,225	\$379,042	\$330,011	\$108,946	\$95,376	\$55,022	\$24,211	\$32,756	\$46,254	\$76,385	\$1,806,271
Basis Hedges	-\$70,500	-\$82,800	-\$127,360	-\$112,090	-\$76,815	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$469,565
Impact of Financial Hedges	\$10,127	\$144,616	\$222,865	\$266,952	\$253,196	\$108,946	\$95,376	\$55,022	\$24,211	\$32,756	\$46,254	\$76,385	\$1,336,706
Total Pipeline Costs (Incl Inj)	\$6,871,173	\$10,696,592	\$13,894,523	\$12,316,920	\$9,078,867	\$5,583,984	\$3,979,727	\$2,789,029	\$2,495,422	\$2,519,031	\$3,100,664	\$5,017,264	\$78,343,195
Total Delivered Pipeline Vol	2,566,928	3,651,361	4,190,540	3,765,383	3,185,565	2,288,993	1,725,270	1,221,301	1,092,478	1,097,557	1,418,190	2,235,858	28,439,424
WACOG (Cost/Volume)	\$2,677	\$2,929	\$3,316	\$3,271	\$2,850	\$2,439	\$2,307	\$2,284	\$2,284	\$2,295	\$2,186	\$2,244	\$2,755
Injections	0	0	0	0	0	225,236	488,464	437,577	480,114	479,564	631,231	621,506	3,363,692
Cost of Injections	\$0	\$0	\$0	\$0	\$0	\$538,743	\$1,099,751	\$979,561	\$1,086,028	\$1,086,347	\$1,359,507	\$1,373,426	\$7,523,362
Total GCR Cost Including Financial Hedges, Excluding Injections													
Total Pipeline Costs	\$6,871,173	\$10,696,592	\$13,894,523	\$12,316,920	\$9,078,867	\$5,045,242	\$2,879,977	\$1,809,468	\$1,409,393	\$1,432,685	\$1,741,157	\$3,643,838	\$70,819,834
Total Pipeline Purchase Volumes	2,566,928	3,651,361	4,190,540	3,765,383	3,185,565	2,063,757	1,236,805	783,724	612,364	617,993	786,959	1,614,352	25,075,732

## PIPELINE FIXED COST UNIT PRICES

## STORAGE FIXED COST UNIT PRICES



686,284  
300,000  
507,600  
500,000  
321,000  
531,000

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19
<b>PIPELINE FIXED COST DOLLARS</b>						<b>TOTAL COST</b>						
ALGONQUIN AFT-EA/FT-1 DEMAND	\$	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759
ALGONQUIN AFT-3 DEMAND	\$	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722
ALGONQUIN AFT-ES/1S DEMAND	\$	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725
ALGONQUIN AIM DEMAND	\$	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152
ALGONQUIN AFT-CLMS DEMAND (Cray St)	\$	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800
CANADIAN CAPACITY AIA FEE	\$	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350
COLUMBIA FTS DEMAND	\$	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242
DOMINION FTNN DEMAND	\$	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667
IROQUOIS DEMAND	\$	\$175,473	\$181,322	\$181,322	\$175,473	\$181,322	\$181,322	\$175,473	\$181,322	\$181,322	\$175,473	\$181,322
MILLENNIUM DEMAND	\$	\$258,168	\$266,774	\$266,774	\$266,774	\$258,168	\$266,774	\$266,774	\$266,774	\$266,774	\$258,168	\$266,774
PORTLAND NATURAL GAS DEMAND	\$	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328
TENNESSEE FT-A DEMAND ZONE 0 TO 6	\$	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894
TENNESSEE FT-A DEMAND ZONE 1 TO 6	\$	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001
TENNESSEE FT-A DEMAND ZONE 0 TO 6	\$	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	\$	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994
TENNESSEE FT-A DEMAND ZONE 5 TO 6	\$	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793
TENNESSEE FT-A DEMAND DRACUT	\$	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232	\$56,232
TENNESSEE FT-A DEMAND DRACUT FOR PEAKI	\$	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382	\$81,382
TENNESSEE FT-A DEMAND EVERETT	\$	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633
TEXAS EASTERN CDS STX DEMAND M3	\$	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208
TEXAS EASTERN CDS WLA DEMAND M3	\$	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413
TEXAS EASTERN CDS ELA DEMAND M3	\$	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425
TEXAS EASTERN CDS ETX DEMAND M3	\$	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501
TEXAS EASTERN CDS 1-3 DEMAND M3	\$	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105
TEXAS EASTERN FTS DEMAND	\$	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873
TEXAS EASTERN SCT STX DEMAND M3	\$	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554
TEXAS EASTERN SCT WLA DEMAND M3	\$	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733
TEXAS EASTERN SCT ELA DEMAND M3	\$	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124
TEXAS EASTERN SCT ETX DEMAND M3	\$	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288
TEXAS EASTERN SCT 1-3 DEMAND M3	\$	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950
TRANSCANADA TO WADDINGTON DEMAND	\$	\$11,366	\$11,745	\$11,745	\$11,366	\$11,366	\$11,745	\$11,366	\$11,745	\$11,745	\$11,366	\$11,745
TRANSCANADA TO EAST HEREFORD DEMAND	\$	\$202,527	\$209,278	\$209,278	\$202,527	\$209,278	\$209,278	\$202,527	\$209,278	\$209,278	\$202,527	\$209,278
TRANSCONTINENTAL DEMAND	\$	\$4,848	\$5,010	\$5,010	\$4,848	\$5,010	\$5,010	\$4,848	\$5,010	\$5,010	\$4,848	\$5,010
UNION DEMAND	\$	\$35,933	\$37,130	\$37,130	\$35,933	\$37,130	\$37,130	\$35,933	\$37,130	\$37,130	\$35,933	\$37,130
WESTERLY LATERAL (Yankee Gas)	\$											
<b>TOTAL PIPELINE DEMAND COSTS</b>												
<b>STORAGE FIXED COST DOLLARS</b>												
COLUMBIA FSS DEMAND	\$	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820	\$3,820
COLUMBIA FSS CAPACITY	\$	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874	\$5,874
DOMINION GSS DEMAND	\$	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292	\$21,292
DOMINION GSS CAPACITY	\$	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070	\$15,070
DOMINION GSS-TE DEMAND	\$	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770	\$26,770
DOMINION GSS-TE CAPACITY	\$	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957	\$19,957
TENNESSEE FSMA DEMAND	\$	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622	\$31,622
TENNESSEE FSMA CAPACITY	\$	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715	\$16,715
TEXAS EASTERN SS-1 DEMAND	\$	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419	\$80,419
TEXAS EASTERN SS-1 CAPACITY	\$	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361	\$13,361
TEXAS EASTERN FSS-1 DEMAND	\$	\$846	\$846	\$846	\$846	\$846	\$846	\$846	\$846	\$846	\$846	\$846
TEXAS EASTERN FSS-1 CAPACITY	\$	\$610	\$610	\$610	\$610	\$610	\$610	\$610	\$610	\$610	\$610	\$610
NATIONAL GRID LING TANK LEASE PAYMENTS	\$	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740	\$163,740
<b>TOTAL STORAGE DEMAND COSTS</b>												

\$1,964,880  
\$4,801,150

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

\$3,820  
\$5,874  
\$21,292  
\$15,070  
\$26,770  
\$19,957  
\$31,622  
\$16,715  
\$80,419  
\$13,361  
\$846  
\$610  
\$163,740  
\$400,096

[illegible][illegible]

Marketer Demand Charge Credits													Total
Capacity Release Volumes as of January 1, 2018													
	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	
Tennessee Zone 1	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	
Tennessee Dracut	229	229	229	229	229	229	229	229	229	229	229	229	
Algonquin	2,313	2,313	2,313	2,313	2,313	2,313	2,313	2,313	2,313	2,313	2,313	2,313	
Tetco STX/AGT	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	
Tetco WLA/AGT	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	
Tetco ELA/AGT	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	
Columbia/AGT	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	
<b>Total</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	<b>33,451</b>	
<b>System Weighted Average cost per MMBtu</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	<b>\$26.0957</b>	
<b>Total Demand Charge Credit</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$872,928</b>	<b>\$10,475,131</b>
<b>Demand Costs Net of Releases to Marketers</b>	<b>\$4,729,063</b>	<b>\$10,471,730</b>	<b>\$10,470,396</b>	<b>\$10,401,565</b>	<b>\$10,470,396</b>	<b>\$4,886,910</b>	<b>\$4,909,854</b>	<b>\$4,933,176</b>	<b>\$4,956,120</b>	<b>\$4,956,120</b>	<b>\$4,933,176</b>	<b>\$4,956,120</b>	<b>\$81,074,626</b>

[illegible]



**Storage Withdrawal Variable Costs  
2018-2019 GCR Storage Estimate**

**Storage Withdrawals at Facility (Dth)**

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
TENNESSEE FSMA 501	16,749	143,559	100,994	36,931	147,312	0	0	0	0	0	0	0
DOMINION GSS 300170	0	95,143	115,827	108,411	35,722	0	0	0	0	0	0	0
DOMINION GSS 300168	5,604	33,867	36,426	36,370	26,243	0	0	0	0	0	0	0
DOMINION GSS 300171	0	30,314	69,861	60,091	22,883	0	0	0	0	0	0	0
DOMINION GSSTE 600045	63,343	65,454	65,454	59,120	65,454	63,343	0	0	0	0	0	0
TETCO FSS-1 400515	0	14,095	14,095	14,095	12,403	0	0	0	0	0	0	0
TETCO SS-1 400221	0	291,811	291,811	256,793	0	0	0	0	0	0	0	0
TETCO SS-1 400185	0	12,770	12,770	11,238	0	0	0	0	0	0	0	0
DOMINION GSS 300169	0	50,866	55,647	52,844	40,561	0	0	0	0	0	0	0
COLUMBIA FSS 9630	5,090	37,396	71,260	57,008	27,084	0	0	0	0	0	0	0
TENNESSEE 62918	0	29,618	49,345	91,670	33,068	0	0	0	0	0	0	0
TOTAL WITHDRAWALS	90,786	804,893	883,488	821,120	678,761	63,343	0	0	0	0	0	0

**Storage Withdrawal Charges**

Tennessee Withdrawal	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087	\$0.0087
Dominion GSS Withdrawal	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167	\$0.0167
Dominion GSS-TE Withdrawal	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210	\$0.0210
TETCO SS-1 Withdrawal	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489	\$0.0489
TETCO FSS-1 Withdrawal	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311	\$0.0311
Columbia Withdrawal	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153

**Storage Withdrawal Costs**

Tennessee Withdrawal	\$146	\$1,507	\$1,308	\$1,119	\$1,569	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Dominion GSS Withdrawal	\$94	\$3,510	\$4,639	\$4,304	\$2,094	\$1,330	\$0	\$0	\$0	\$0	\$0	\$0
Dominion GSS-TE Withdrawal	\$1,330	\$1,375	\$1,375	\$1,242	\$1,375	\$1,330	\$0	\$0	\$0	\$0	\$0	\$0
TETCO SS-1 Withdrawal	\$0	\$14,894	\$14,894	\$14,894	\$13,107	\$0	\$0	\$0	\$0	\$0	\$0	\$0
TETCO FSS-1 Withdrawal	\$0	\$438	\$438	\$438	\$386	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Columbia Withdrawal	\$78	\$572	\$1,090	\$872	\$414	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Storage Withdrawal Costs	\$1,647	\$22,296	\$23,744	\$22,869	\$18,945	\$1,330	\$0	\$0	\$0	\$0	\$0	\$0

**Storage Withdrawals at Gate (Dth)**

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
TENNESSEE FSMA 501	16,542	141,779	99,741	36,473	145,486	0	0	0	0	0	0	0
DOMINION GSS 300170	0	92,131	112,160	104,979	34,591	0	0	0	0	0	0	0
DOMINION GSS 300168	5,535	33,447	35,974	35,919	25,918	0	0	0	0	0	0	0
DOMINION GSS 300171	0	29,600	68,215	58,699	22,353	0	0	0	0	0	0	0
DOMINION GSSTE 600045	61,743	63,692	63,692	57,551	63,717	61,886	0	0	0	0	0	0
TETCO FSS-1 400515	0	13,664	13,664	13,669	12,029	0	0	0	0	0	0	0
TETCO SS-1 400221	0	288,307	288,307	288,776	254,123	0	0	0	0	0	0	0
TETCO SS-1 400185	0	12,617	12,617	12,637	11,121	0	0	0	0	0	0	0
DOMINION GSS 300169	0	49,335	53,973	51,275	39,356	0	0	0	0	0	0	0
COLUMBIA FSS 9630	4,982	69,466	69,466	55,595	26,413	0	0	0	0	0	0	0
TENNESSEE 62918	0	29,251	48,733	90,533	32,657	0	0	0	0	0	0	0
TOTAL WITHDRAWALS	88,801	790,276	866,540	806,106	667,763	61,886	0	0	0	0	0	0

**Storage Transportation Charges**

Tennessee Transport	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181
Dominion Transport on TETCO/AGT	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138	\$0.0138
Dominion Transport on DTI/TETCO/AGT	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308	\$0.0308
Dominion Transport on Tennessee	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181
Dominion Transport on DTI/Tennessee	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351	\$0.1351
TETCO SS-1 Transport	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125
TETCO FSS-1 Transport	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517	\$0.0517
Columbia Transport	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325	\$0.0325

**Storage Transportation Costs**

Tennessee Transport	\$1,954	\$20,199	\$17,535	\$14,999	\$21,039	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Dominion Transport on TETCO/AGT	\$852	\$1,287	\$1,820	\$1,604	\$1,188	\$854	\$0	\$0	\$0	\$0	\$0	\$0
Dominion Transport on DTI/TETCO/AGT	\$0	\$1,520	\$1,662	\$1,579	\$1,212	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Dominion Transport on Tennessee	\$654	\$3,950	\$4,249	\$4,242	\$3,061	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Dominion Transport on DTI/Tennessee	\$0	\$12,447	\$15,153	\$14,183	\$4,673	\$0	\$0	\$0	\$0	\$0	\$0	\$0
TETCO FSS-1 Transport	\$0	\$3,762	\$3,762	\$3,768	\$3,316	\$0	\$0	\$0	\$0	\$0	\$0	\$0
TETCO FSS-1 Transport	\$0	\$706	\$706	\$706	\$621	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Columbia Transport	\$162	\$1,185	\$2,258	\$1,807	\$858	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Storage Transportation Costs	\$3,621	\$45,055	\$47,144	\$42,888	\$35,968	\$854	\$0	\$0	\$0	\$0	\$0	\$0

**Total Storage Variable Costs**

	\$5,269	\$67,351	\$70,888	\$65,757	\$54,913	\$2,184	\$0	\$0	\$0	\$0	\$0	\$0
--	---------	----------	----------	----------	----------	---------	-----	-----	-----	-----	-----	-----

**NATIONAL GRID - RI SERVICE AREA  
NOVEMBER 2018 - OCTOBER 2019**

**LNG Estimate for 2018 - 2019**

**LNG Supply Costs**

08/02/2018 NYMEX  
Trucking ENGIE

Basis ENGIE Gas Contract  
Delivered Cost ENGIE Gas

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
	\$2,857	\$2,958	\$3,043	\$3,006	\$2,903	\$2,605	\$2,578	\$2,608	\$2,642	\$2,648	\$2,629	\$2,645	

**Combined LNG Inventory**

Beginning Inventory Volume  
ENGIE Summer Injections  
ENGIE Winter Injections  
Volume Withdrawn

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
	32,757	154,926	479,678	187,614	101,636	16,632	17,187	16,632	17,187	17,187	16,632	17,187	1,075,253

**Beginning Inventory**

Injection Costs

Withdrawal Costs

Ending Volume

Ending Inventory

	\$165,069	\$780,701	\$2,321,880	\$908,144	\$459,547	\$69,065	\$70,759	\$68,122	\$70,410	\$70,446	\$68,173	\$70,543	\$5,122,858

Average Cost Per Dth

	\$5.039	\$4,840	\$4,840	\$4,522	\$4,152	\$4,117	\$4,096	\$4,097	\$4,099	\$4,099	\$4,105	\$4,105	
--	---------	---------	---------	---------	---------	---------	---------	---------	---------	---------	---------	---------	--

**Portable Vapor**

Portable Vapor Volume

Average Cost Per Dth

Total Cost

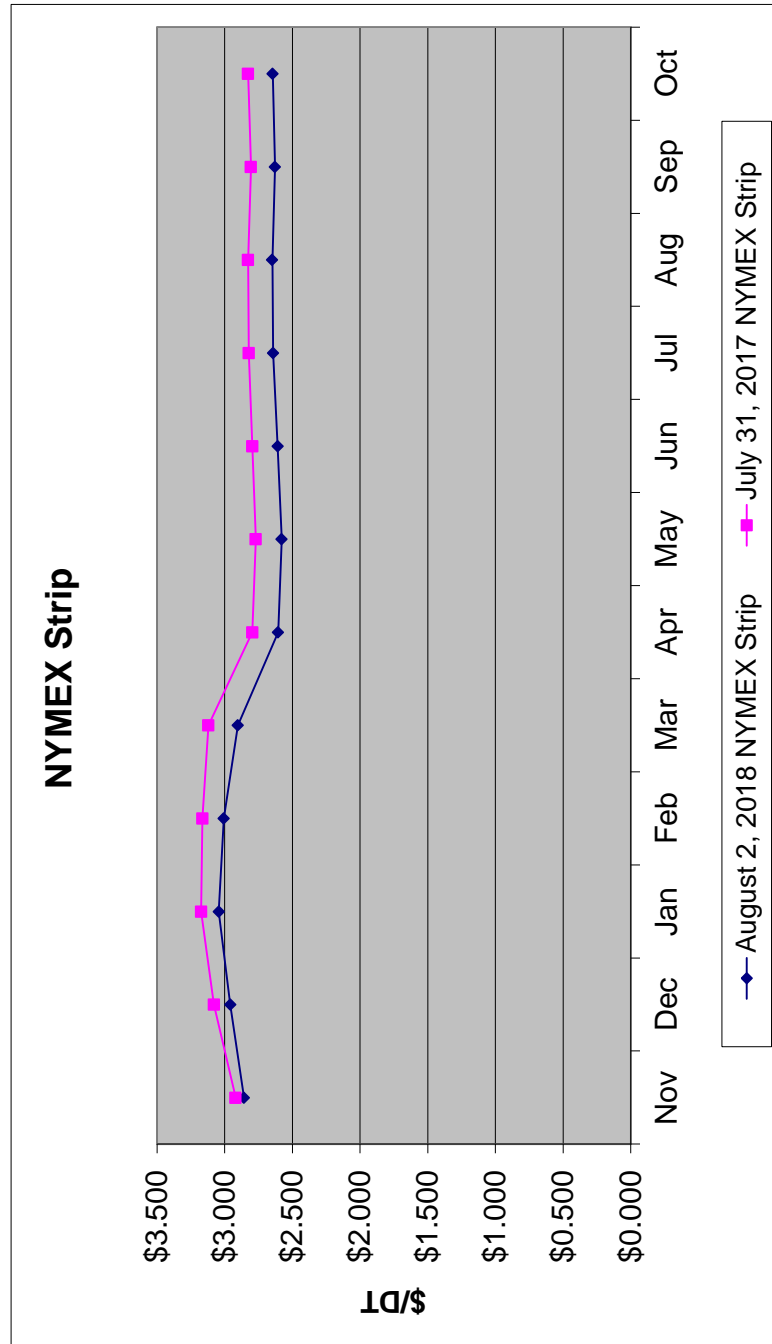
	0	0	0	0	0	0	0	0	0	0	0	0	\$0
	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

**Total All LNG Costs**

	\$165,069	\$780,701	\$2,321,880	\$908,144	\$459,547	\$69,065	\$70,759	\$68,122	\$70,410	\$70,446	\$68,173	\$70,543	\$5,122,858
--	-----------	-----------	-------------	-----------	-----------	----------	----------	----------	----------	----------	----------	----------	-------------



	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
July 31, 2017 NYMEX Strip	\$2.920	\$3.079	\$3.173	\$3.164	\$3.119	\$2.795	\$2.769	\$2.795	\$2.821	\$2.826	\$2.806	\$2.826
August 2, 2018 NYMEX Strip	\$2.857	\$2.958	\$3.043	\$3.006	\$2.903	\$2.605	\$2.578	\$2.608	\$2.642	\$2.648	\$2.629	\$2.645





**PRELIMINARY**

**National Grid  
Summary of Transportation Capacity Release  
Pipeline Path Availability and Pricing  
November 2018 - October 2019**

Path to City Gate	As of 8/1/18 Existing Releases	Total Available	Remaining Available	Cost per Dth	New Credit or Surcharge	Old Credit or Surcharge
Company Weighted Average						
Tennessee Zone 1	9,500	9,500	0	\$1.0298	(\$0.2605)	(\$0.3899)
Tennessee Dracut	215	1,000	785	\$2.2692	(\$1.4999)	(\$1.1273)
Algonquin @ Lambertville, NJ	2,370	2,714	344	\$0.5192	\$0.2501	\$0.2661
Texas Eastern - South Texas Algonquin @ Lambertville, NJ	4,044	4,044	0	\$1.1580	(\$0.3887)	(\$0.4998)
Texas Eastern - West La Algonquin @ Lambertville, NJ	8,500	8,500	0	\$0.8774	(\$0.1081)	(\$0.2549)
Texas Eastern - East La Algonquin @ Lambertville, NJ	6,500	6,500	0	\$0.7847	(\$0.0154)	(\$0.1462)
Columbia (Maumee/Pennsburg) at 5:1 ratio*	2,458	3,000	542	\$0.2702	\$0.4991	\$0.2470
<b>Totals:</b>	33,587	35,258	1,671			

Gas Year 2018 - 2019  
TEXAS EASTERN SOUTH TEXAS SUPPLY PATH COST MATRIX  
CITY GATE DELIVERED MDQ = 4,044

UNIT PRICING

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
<b>FIXED</b>													
TETCO STX SUPPLY ZONE DEMAND	\$/Dth	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050
TECCO WLA SUPPLY ZONE DEMAND	\$/Dth	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260
TETCO ELA SUPPLY ZONE DEMAND	\$/Dth	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750
TETCO M1 TO M3 DEMAND	\$/Dth	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480
ALGONQUIN AFT-E DEMAND	\$/Dth	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734
<b>VARIABLE</b>													
TETCO USAGE STX TO M3	\$/Dth	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728	\$0.0728
ALGONQUIN USAGE	\$/Dth	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125
08/02/2018 NYMEX	\$/Dth	\$2.8570	\$2.9580	\$3.0430	\$3.0060	\$2.9030	\$2.6050	\$2.6080	\$2.6420	\$2.6480	\$2.6290	\$2.6450	\$2.6450
SUPPLY AREA BASIS	\$/Dth	(\$0.0170)	(\$0.0750)	(\$0.0800)	(\$0.0820)	(\$0.0730)	\$0.0130	\$0.0230	(\$0.0050)	(\$0.0050)	\$0.0050	(\$0.0030)	(\$0.0030)
NET COST AFTER BASIS	\$/Dth	\$2.8400	\$2.8830	\$2.9630	\$2.9240	\$2.8300	\$2.6180	\$2.6310	\$2.6370	\$2.6430	\$2.6340	\$2.6420	\$2.6420

BILLING UNITS

<b>FIXED</b>													
TETCO STX SUPPLY ZONE DEMAND	\$/Dth	4.088	4.088	4.088	4.086	4.086	4.072	4.072	4.072	4.072	4.072	4.072	4.072
TECCO WLA SUPPLY ZONE DEMAND	\$/Dth	4.088	4.088	4.088	4.086	4.086	4.072	4.072	4.072	4.072	4.072	4.072	4.072
TETCO ELA SUPPLY ZONE DEMAND	\$/Dth	4.088	4.088	4.088	4.086	4.086	4.072	4.072	4.072	4.072	4.072	4.072	4.072
TETCO M1 TO M3 DEMAND	\$/Dth	4.088	4.088	4.088	4.086	4.086	4.072	4.072	4.072	4.072	4.072	4.072	4.072
ALGONQUIN AFT-E DEMAND	\$/Dth	4.044	4.044	4.044	4.044	4.044	4.044	4.044	4.044	4.044	4.044	4.044	4.044
<b>VARIABLE</b>													
PURCHASE VOLUMES	Dth	126,424	132,441	132,441	119,576	132,387	126,424	126,424	130,638	130,638	126,424	130,638	1,545,091
TETCO USAGE STX TO M3	Dth	122,151	126,733	126,733	114,422	126,681	122,151	126,222	122,151	126,222	122,151	126,222	1,488,061
ALGONQUIN USAGE	Dth	121,320	125,364	125,364	113,232	125,364	121,320	125,364	125,364	125,364	121,320	125,364	1,476,060
DELIVERED VOLUMES	Dth	121,320	125,364	125,364	113,232	125,364	121,320	125,364	125,364	125,364	121,320	125,364	1,476,060

FUEL USE %

TETCO STX TO M3 FUEL	%	3.38%	4.31%	4.31%	4.31%	4.31%	3.38%	3.38%	3.38%	3.38%	3.38%	3.38%	3.38%
ALGONQUIN AFT-E FUEL	%	0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%

TRANSPORTATION COST

<b>FIXED</b>													
TETCO STX SUPPLY ZONE DEMAND	\$	\$27,708	\$27,820	\$27,820	\$27,809	\$27,809	\$27,708	\$27,708	\$27,708	\$27,708	\$27,708	\$27,708	\$332,920
TECCO WLA SUPPLY ZONE DEMAND	\$	\$11,507	\$11,553	\$11,553	\$11,548	\$11,548	\$11,507	\$11,507	\$11,507	\$11,507	\$11,507	\$11,507	\$138,256
TETCO ELA SUPPLY ZONE DEMAND	\$	\$9,670	\$9,709	\$9,709	\$9,705	\$9,705	\$9,670	\$9,670	\$9,670	\$9,670	\$9,670	\$9,670	\$116,192
TETCO M1 TO M3 DEMAND	\$	\$43,355	\$43,531	\$43,531	\$43,513	\$43,513	\$43,355	\$43,355	\$43,355	\$43,355	\$43,355	\$43,355	\$520,930
ALGONQUIN AFT-E DEMAND	\$	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$26,583	\$318,994
<b>VARIABLE</b>													
TETCO USAGE STX TO M3	\$	\$8,893	\$9,226	\$9,226	\$8,330	\$9,222	\$8,893	\$9,189	\$9,189	\$9,189	\$8,893	\$9,189	\$108,331
ALGONQUIN USAGE	\$	\$1,517	\$1,567	\$1,567	\$1,415	\$1,567	\$1,517	\$1,567	\$1,567	\$1,567	\$1,517	\$1,567	\$18,451
PURCHASE COST	\$	\$359,043	\$381,827	\$392,422	\$349,639	\$374,656	\$330,977	\$338,744	\$344,492	\$345,276	\$333,000	\$345,145	\$4,227,844
<b>TOTAL FIXED</b>	\$	\$118,823	\$119,196	\$119,196	\$119,158	\$119,158	\$118,823	\$118,823	\$118,823	\$118,823	\$118,823	\$118,823	\$1,427,291
<b>TOTAL VARIABLE</b>	\$	\$369,453	\$392,620	\$403,216	\$359,385	\$385,446	\$341,386	\$349,500	\$355,248	\$356,032	\$343,409	\$355,901	\$4,354,626
DELIVERED COST AT NYMEX	\$	\$346,611	\$370,827	\$381,483	\$340,375	\$363,932	\$316,039	\$323,188	\$331,212	\$331,964	\$318,950	\$331,588	\$4,072,571
NET NON-GAS VARIABLE COST	\$	\$22,841	\$17,994	\$21,733	\$19,009	\$21,514	\$25,348	\$26,312	\$24,036	\$24,068	\$24,459	\$24,314	\$282,055
AVERAGE NON-GAS VARIABLE COST	\$/Dth	\$0.1883	\$0.1738	\$0.1734	\$0.1679	\$0.1716	\$0.2089	\$0.2099	\$0.1917	\$0.1920	\$0.2016	\$0.1939	\$0.1911
AVERAGE FIXED COST	\$/Dth												\$29,417
AVERAGE COST AT 100% LOAD FACTOR	\$/Dth												\$0.9670
TOTAL PATH COST	\$/Dth												\$1.1580

Gas Year 2018 - 2019  
TEXAS EASTERN WEST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE  
CITY GATE DELIVERED MDQ = 8,500

UNIT PRICING

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
<b>FIXED</b>													
TETCO WLA SUPPLY ZONE DEMAND	\$/Dth	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260	\$2,8260
TETCO ELA SUPPLY ZONE DEMAND	\$/Dth	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750
TETCO M1 TO M3 DEMAND	\$/Dth	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480
ALGONQUIN AFT-E DEMAND	\$/Dth	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734
<b>VARIABLE</b>													
TETCO USAGE WLA TO M3	\$/Dth	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697	\$0,0697
ALGONQUIN USAGE	\$/Dth	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125
08/02/2018 NYMEX	\$/Dth	\$2,8570	\$2,9680	\$3,0430	\$3,0060	\$2,9030	\$2,5780	\$2,6080	\$2,6420	\$2,6480	\$2,6290	\$2,6450	\$2,6450
SUPPLY AREA BASIS	\$/Dth	(\$0,0530)	(\$0,0500)	(\$0,0870)	(\$0,0750)	(\$0,0730)	(\$0,0650)	(\$0,0720)	(\$0,0750)	(\$0,0750)	(\$0,0730)	(\$0,0700)	(\$0,0700)
NET COST AFTER BASIS	\$/Dth	\$2,8040	\$2,9080	\$2,9560	\$2,9310	\$2,8300	\$2,5130	\$2,5360	\$2,5670	\$2,5730	\$2,5560	\$2,5750	\$2,5750

BILLING UNITS

<b>FIXED</b>													
TETCO WLA SUPPLY ZONE DEMAND	Dth	8,558	8,593	8,589	8,589	8,589	8,558	8,558	8,558	8,558	8,558	8,558	8,558
TETCO ELA SUPPLY ZONE DEMAND	Dth	8,558	8,593	8,589	8,589	8,589	8,558	8,558	8,558	8,558	8,558	8,558	8,558
TETCO M1 TO M3 DEMAND	Dth	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	102,000
ALGONQUIN AFT-E DEMAND	Dth	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
<b>VARIABLE</b>													
PURCHASE VOLUMES	Dth	265,398	277,881	277,881	250,888	277,769	274,244	266,398	274,244	274,244	265,398	274,244	3,242,988
TETCO USAGE WLA TO M3	Dth	256,746	266,377	266,377	240,501	266,269	265,304	256,746	265,304	265,304	256,746	265,304	3,127,724
ALGONQUIN USAGE	Dth	255,000	263,500	263,500	238,000	263,500	263,500	255,000	263,500	263,500	255,000	263,500	3,102,500
DELIVERED VOLUMES	Dth	255,000	263,500	263,500	238,000	263,500	263,500	255,000	263,500	263,500	255,000	263,500	3,102,500

FUEL USE %

TETCO WLA TO M3 FUEL	%	3.26%	4.14%	4.14%	4.14%	4.14%	3.26%	3.26%	3.26%	3.26%	3.26%	3.26%	3.26%
ALGONQUIN AFT-E FUEL	%	0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%

TRANSPORTATION COST

<b>FIXED</b>													
TETCO WLA SUPPLY ZONE DEMAND	\$	\$24,185	\$24,283	\$24,283	\$24,273	\$24,185	\$24,185	\$24,185	\$24,185	\$24,185	\$24,185	\$24,185	\$290,597
TETCO ELA SUPPLY ZONE DEMAND	\$	\$20,326	\$20,408	\$20,408	\$20,400	\$20,326	\$20,326	\$20,326	\$20,326	\$20,326	\$20,326	\$20,326	\$244,221
TETCO M1 TO M3 DEMAND	\$	\$91,128	\$91,496	\$91,496	\$91,459	\$91,128	\$91,128	\$91,128	\$91,128	\$91,128	\$91,128	\$91,128	\$1,094,932
ALGONQUIN AFT-E DEMAND	\$	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$55,874	\$670,487
<b>VARIABLE</b>													
TETCO USAGE WLA TO M3	\$	\$17,895	\$18,566	\$18,566	\$16,763	\$18,559	\$18,492	\$17,895	\$18,492	\$18,492	\$17,895	\$18,492	\$218,002
ALGONQUIN USAGE	\$	\$3,188	\$3,294	\$3,294	\$2,975	\$3,294	\$3,294	\$3,188	\$3,294	\$3,294	\$3,188	\$3,294	\$38,781
PURCHASE COST	\$	\$744,176	\$808,078	\$821,417	\$735,353	\$786,086	\$689,176	\$673,049	\$703,985	\$705,631	\$678,357	\$706,179	\$8,725,067
TOTAL FIXED	\$	\$191,513	\$192,061	\$192,061	\$192,006	\$191,513	\$191,513	\$191,513	\$191,513	\$191,513	\$191,513	\$191,513	\$2,300,237
TOTAL VARIABLE	\$	\$765,258	\$829,939	\$843,277	\$755,091	\$807,938	\$710,962	\$694,132	\$725,771	\$727,416	\$699,440	\$727,965	\$8,981,850
DELIVERED VOLUMES AT NYMEX	\$	\$728,535	\$79,433	\$801,831	\$715,428	\$764,941	\$679,303	\$665,040	\$696,167	\$697,748	\$670,395	\$696,958	\$8,560,053
NET NON-GAS VARIABLE COST	\$	\$36,723	\$50,506	\$41,446	\$39,663	\$42,998	\$31,659	\$29,092	\$29,604	\$29,604	\$29,045	\$31,007	\$421,798
AVERAGE NON-GAS VARIABLE COST	\$/Dth	\$0,1440	\$0,1917	\$0,1573	\$0,1666	\$0,1632	\$0,1201	\$0,1141	\$0,1123	\$0,1126	\$0,1139	\$0,1177	\$0,1360
AVERAGE FIXED COST	\$/Dth												\$22,5513
AVERAGE COST AT 100% LOAD FACTOR	\$/Dth												\$0,7414
TOTAL PATH COST	\$/Dth												\$0,8774

REDACTED

Gas Year 2018 - 2019  
 TEXAS EASTERN EAST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE  
 CITY GATE DELIVERED MDQ = 6,500

UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
<b>FIXED</b>														
TETCO ELA SUPPLY ZONE DEMAND	\$/Dth	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	\$2,3750	
TETCO M1 TO M3 DEMAND	\$/Dth	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	\$10,6480	
ALGONQUIN AFT-E DEMAND	\$/Dth	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	
<b>VARIABLE</b>														
TETCO USAGE ELA TO M3	\$/Dth	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	\$0,0682	
ALGONQUIN USAGE	\$/Dth	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	
08/02/2018 NYMEX	\$/Dth	\$2,8570	\$2,9580	\$3,0430	\$3,0060	\$2,9030	\$2,6050	\$2,5780	\$2,6080	\$2,6420	\$2,6480	\$2,6290	\$2,6450	
SUPPLY AREA BASIS	\$/Dth	(\$0,0670)	(\$0,0680)	(\$0,0680)	(\$0,0680)	(\$0,0650)	(\$0,0630)	(\$0,0600)	(\$0,0600)	(\$0,0700)	(\$0,0700)	(\$0,0670)	(\$0,0650)	
NET COST AFTER BASIS	\$/Dth	\$2,7900	\$2,9000	\$2,9630	\$2,9380	\$2,8380	\$2,5420	\$2,5180	\$2,5400	\$2,5720	\$2,5780	\$2,5620	\$2,5800	
<b>BILLING UNITS</b>														
<b>FIXED</b>														
TETCO ELA SUPPLY ZONE DEMAND	Dth	6,545	6,571	6,571	6,568	6,568	6,545	6,545	6,545	6,545	6,545	6,545	6,545	
TETCO M1 TO M3 DEMAND	Dth	6,545	6,571	6,571	6,568	6,568	6,545	6,545	6,545	6,545	6,545	6,545	6,545	
ALGONQUIN AFT-E DEMAND	Dth	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	78,000
<b>VARIABLE</b>														
PURCHASE VOLUMES	Dth	202,909	212,475	212,475	191,835	212,389	202,909	209,673	202,909	209,673	209,673	202,909	209,673	2,479,504
TETCO USAGE ELA TO M3	Dth	196,335	203,700	203,700	183,913	203,618	196,335	202,880	196,335	202,880	202,880	196,335	202,880	2,391,789
ALGONQUIN USAGE	Dth	195,000	201,500	201,500	182,000	201,500	195,000	201,500	195,000	201,500	201,500	195,000	201,500	2,372,500
DELIVERED VOLUMES	Dth	195,000	201,500	201,500	182,000	201,500	195,000	201,500	195,000	201,500	201,500	195,000	201,500	2,372,500

FUEL USE %

TETCO ELA TO M3 FUEL	%	3.24%	4.13%	4.13%	4.13%	4.13%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	
ALGONQUIN AFT-E FUEL	%	0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	

TRANSPORTATION COST

<b>FIXED</b>														
TETCO ELA SUPPLY ZONE DEMAND	\$	\$15,543	\$15,606	\$15,606	\$15,600	\$15,600	\$15,543	\$15,543	\$15,543	\$15,543	\$15,543	\$15,543	\$15,543	\$186,757
TETCO M1 TO M3 DEMAND	\$	\$69,686	\$69,968	\$69,968	\$69,939	\$69,939	\$69,686	\$69,686	\$69,686	\$69,686	\$69,686	\$69,686	\$69,686	\$837,301
ALGONQUIN AFT-E DEMAND	\$	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$42,727	\$512,725
<b>VARIABLE</b>														
TETCO USAGE ELA TO M3	\$	\$13,390	\$13,892	\$13,892	\$12,543	\$13,887	\$13,390	\$13,836	\$13,390	\$13,836	\$13,836	\$13,390	\$13,836	\$163,120
ALGONQUIN USAGE	\$	\$2,438	\$2,519	\$2,519	\$2,275	\$2,519	\$2,438	\$2,519	\$2,438	\$2,519	\$2,519	\$2,438	\$2,519	\$29,656
PURCHASE COST	\$	\$566,117	\$616,178	\$629,564	\$563,613	\$602,761	\$515,796	\$527,957	\$515,390	\$539,279	\$540,537	\$519,854	\$540,956	\$6,678,000
TOTAL FIXED	\$	\$127,956	\$128,301	\$128,301	\$128,266	\$128,266	\$127,956	\$127,956	\$127,956	\$127,956	\$127,956	\$127,956	\$127,956	\$1,536,783
TOTAL VARIABLE	\$	\$581,945	\$632,589	\$646,975	\$578,431	\$619,166	\$531,623	\$544,312	\$531,217	\$555,634	\$556,892	\$535,681	\$557,311	\$6,870,777
DELIVERED VOLUMES AT NYMEX	\$	\$557,115	\$596,037	\$613,165	\$547,092	\$584,955	\$507,975	\$519,467	\$508,560	\$532,363	\$533,572	\$512,655	\$532,968	\$6,545,923
NET NON-GAS VARIABLE COST	\$	\$24,830	\$36,552	\$32,811	\$31,339	\$34,212	\$23,648	\$24,845	\$22,657	\$23,271	\$23,320	\$23,026	\$24,344	\$324,854
AVERAGE NON-GAS VARIABLE COST	\$/Dth	<b>\$0.1273</b>	<b>\$0.1814</b>	<b>\$0.1628</b>	<b>\$0.1722</b>	<b>\$0.1698</b>	<b>\$0.1213</b>	<b>\$0.1233</b>	<b>\$0.1162</b>	<b>\$0.1155</b>	<b>\$0.1157</b>	<b>\$0.1181</b>	<b>\$0.1208</b>	<b>\$0.1369</b>
AVERAGE FIXED COST	\$/Dth													\$19,7023
AVERAGE COST AT 100% LOAD FACTOR	\$/Dth													<b>\$0.6477</b>
TOTAL PATH COST	\$/Dth													<b>\$0.7847</b>

REDACTED

## UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
COLUMBIA FTS DEMAND	FIXED													
		\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870
		\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734	\$6,5734
	VARIABLE													
		\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202	\$0,0202
		\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125	\$0,0125
		\$2,8570	\$2,9580	\$3,0430	\$3,0060	\$2,9030	\$2,6050	\$2,5780	\$2,6080	\$2,6420	\$2,6480	\$2,6290	\$2,6450	\$2,6450
		\$0,2030	\$0,2120	\$0,2200	\$0,2200	\$0,2670	\$0,2370	\$0,2900	\$0,3220	\$0,3350	\$0,3420	\$0,4320	\$0,4550	\$0,4400
		\$0,1700	\$0,5000	\$2,6800	\$2,5800	\$0,2150	\$0,2050	\$0,3120	\$0,3350	\$0,3280	\$0,3400	\$0,3400	\$0,5100	\$0,4570
		\$2,6540	\$2,7460	\$2,8230	\$2,7860	\$2,6360	\$2,2880	\$2,2880	\$2,2860	\$2,2470	\$2,2160	\$2,1740	\$2,2050	\$2,2050
NET COST AFTER BASIS MAUMEE		\$2,6870	\$3,4580	\$5,7230	\$5,5860	\$3,1180	\$2,4000	\$2,2660	\$2,2730	\$2,3140	\$2,3080	\$2,1190	\$2,1880	
NET COST AFTER BASIS PENNSBURG														
BILLING UNITS														
COLUMBIA FTS DEMAND	FIXED													
		3,044	3,044	3,044	3,044	3,044	3,044	3,044	3,044	3,044	3,044	3,044	3,044	3,044
		3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
	ALGONQUIN DEMAND													36,000
PURCHASE VOLUMES MAUMEE	VARIABLE													
		76,628	78,346	78,346	70,736	78,314	75,513	78,031	75,513	78,031	78,031	75,513	78,031	78,031
		15,326	15,669	15,669	14,147	15,663	15,103	15,606	15,103	15,606	15,606	15,103	15,606	15,606
	PURCHASE VOLUMES PENNSBURG													93,637
COLUMBIA USAGE		90,616	94,015	94,015	84,883	93,977	90,616	93,637	90,616	93,637	93,637	90,616	93,637	93,637
		90,000	93,000	93,000	84,000	90,000	90,000	93,000	90,000	93,000	93,000	90,000	93,000	93,000
		75,000	77,500	77,500	70,000	77,500	75,000	77,500	75,000	77,500	77,500	75,000	77,500	77,500
	DELIVERED VOLUMES MAUMEE													912,500
DELIVERED VOLUMES PENNSBURG		15,000	15,500	15,500	14,000	15,500	15,000	15,500	15,000	15,500	15,500	15,000	15,500	182,500
COLUMBIA FUEL		1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	1,454%	
		0,68%	1,08%	1,08%	1,04%	1,04%	0,68%	0,68%	0,68%	0,68%	0,68%	0,68%	0,68%	
ALGONQUIN AFT-E FUEL														
TRANSPORTATION COST														
COLUMBIA FTS DEMAND	FIXED													
		\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139	\$19,139
		\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720	\$19,720
	VARIABLE													
		\$1,830	\$1,899	\$1,899	\$1,715	\$1,898	\$1,830	\$1,891	\$1,830	\$1,891	\$1,891	\$1,830	\$1,891	\$1,891
		\$1,125	\$1,163	\$1,163	\$1,050	\$1,163	\$1,125	\$1,163	\$1,125	\$1,163	\$1,163	\$1,125	\$1,163	\$1,163
		\$203,370	\$215,138	\$221,171	\$197,070	\$206,437	\$178,816	\$178,534	\$172,624	\$175,335	\$172,916	\$164,166	\$172,057	\$172,057
		\$41,180	\$54,184	\$69,675	\$79,026	\$48,837	\$36,246	\$35,363	\$36,328	\$36,113	\$36,019	\$32,003	\$34,146	\$34,146
TOTAL FIXED		\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859	\$38,859
	TOTAL VARIABLE	\$247,505	\$272,384	\$313,908	\$278,860	\$258,335	\$218,018	\$216,951	\$209,908	\$214,501	\$211,989	\$199,124	\$209,258	\$209,258
DELIVERED VOLUMES AT NYMEX		\$257,130	\$275,094	\$282,999	\$252,504	\$269,979	\$234,450	\$239,754	\$234,720	\$245,706	\$246,264	\$236,610	\$245,985	\$3,021,195
		-\$9,625	-\$2,710	\$30,909	\$26,356	-\$11,644	-\$16,432	-\$22,803	-\$34,812	-\$31,205	-\$34,275	-\$37,486	-\$36,727	-\$170,454
	NET NON-GAS VARIABLE COST													
	AVERAGE NON-GAS VARIABLE COST	\$/Dth	-\$0,1069	-\$0,0291	\$0,3324	\$0,3138	-\$0,1252	-\$0,1826	-\$0,2452	-\$0,2757	-\$0,3355	-\$0,3686	-\$0,4165	-\$0,3949
AVERAGE FIXED COST														
AVERAGE COST AT 100% LOAD FACTOR														
TOTAL PATH COST														

Gas Year 2018 - 2019			
TENNESSEE ZONE 1 TO CITY GATE			
CITY GATE DELIVERED MDQ = 9,500			
<b>FIXED</b>			
TENNESSEE ZONE 1 TO 6 DEMAND		\$/Dth	
<b>VARIABLE</b>			
TENNESSEE ZONE 1 TO 6 USAGE		\$/Dth	
08/02/2018 NYMEX		\$/Dth	
SUPPLY AREA BASIS		\$/Dth	
NET COST AFTER BASIS		\$/Dth	
<b>FIXED</b>			
TENNESSEE ZONE 1 TO 6 DEMAND		Dth	
<b>VARIABLE</b>			
PURCHASE VOLUMES		Dth	
TENNESSEE ZONE 1 TO 6 USAGE		Dth	
DELIVERED VOLUMES		Dth	
TENNESSEE ZONE 1 TO 6 FUEL		%	
<b>FIXED</b>			
TENNESSEE ZONE 1 TO 6 DEMAND		\$	
<b>VARIABLE</b>			
TENNESSEE ZONE 1 TO 6 USAGE		\$	
PURCHASE COST		\$	
TOTAL FIXED		\$	
TOTAL VARIABLE		\$	
DELIVERED VOLUMES AT NYMEX		\$	
NET NON-GAS VARIABLE COST		\$	
AVERAGE NON-GAS VARIABLE COST		\$/Dth	
AVERAGE FIXED COST		\$/Dth	
AVERAGE COST AT 100% LOAD FACTOR		\$/Dth	
TOTAL PATH COST		\$/Dth	

Gas Year 2018 - 2019  
ALGONQUIN LAMBERTVILLE TO CITY GATE  
CITY GATE DELIVERED MDQ = 2,714

Gas Year 2018 - 2019  
**TENNESSEE DRACUT TO CITY GATE**  
**CITY GATE DELIVERED MDQ = 1,000**

**UNIT PRICING**

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
<b>FIXED</b>														
TENNESSEE ZONE 6 TO 6 DEMAND	\$/Dth	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	\$4,7453	
<b>VARIABLE</b>														
TENNESSEE ZONE 6 TO 6 USAGE	\$/Dth	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	
08/02/2018 NYMEX	\$/Dth	\$2,8570	\$2,9680	\$3,0430	\$3,0060	\$2,9030	\$2,6050	\$2,5780	\$2,6080	\$2,6420	\$2,6480	\$2,6290	\$2,6450	
SUPPLY AREA BASIS	\$/Dth	\$0.9030	\$4,5780	\$8,0550	\$7,9460	\$3,0570	\$0,5870	(\$0,0740)	\$0,0190	\$0,0510	\$0,0640	(\$0,0840)	\$0,1100	
NET COST AFTER BASIS	\$/Dth	\$3,7600	\$7,5360	\$11,0980	\$10,9520	\$5,9600	\$3,1920	\$2,5040	\$2,6270	\$2,6930	\$2,7720	\$2,5450	\$2,7550	
<b>BILLING UNITS</b>														
<b>FIXED</b>														
TENNESSEE ZONE 6 TO 6 DEMAND	Dth	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
<b>VARIABLE</b>														
PURCHASE VOLUMES	Dth	30,030	31,031	31,031	28,028	31,031	30,030	31,031	30,030	31,031	31,031	30,030	31,031	365,365
TENNESSEE ZONE 6 TO 6 USAGE	Dth	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	365,000
DELIVERED VOLUMES	Dth	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	365,000
<b>FUEL USE %</b>														
TENNESSEE ZONE 6 TO 6 FUEL	%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
<b>TRANSPORTATION COST</b>														
<b>FIXED</b>														
TENNESSEE ZONE 6 TO 6 DEMAND	\$	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$56,944
<b>VARIABLE</b>														
TENNESSEE ZONE 6 TO 6 USAGE	\$	\$1,089	\$1,125	\$1,125	\$1,016	\$1,125	\$1,089	\$1,125	\$1,089	\$1,125	\$1,125	\$1,089	\$1,125	\$13,250
PURCHASE COST	\$	\$112,913	\$233,850	\$344,382	\$306,963	\$184,945	\$95,856	\$77,702	\$78,889	\$83,567	\$84,156	\$76,426	\$85,490	\$1,765,139
<b>TOTAL FIXED</b>	\$	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$4,745	\$56,944
<b>TOTAL VARIABLE</b>	\$	\$114,002	\$234,975	\$345,508	\$307,979	\$186,070	\$96,945	\$78,827	\$79,978	\$84,692	\$85,281	\$77,515	\$86,616	\$1,778,389
<b>DELIVERED VOLUMES AT NYMEX</b>	\$	\$85,710	\$91,698	\$94,333	\$84,168	\$89,993	\$78,150	\$79,918	\$78,240	\$81,902	\$82,088	\$78,870	\$81,995	\$1,007,065
<b>NET NON-GAS VARIABLE COST</b>	\$	\$28,292	\$143,277	\$251,175	\$223,811	\$96,077	\$18,795	-\$1,091	\$1,738	\$2,790	\$3,193	-\$1,355	\$4,621	\$771,324
<b>AVERAGE NON-GAS VARIABLE COST</b>	\$/Dth	<b>\$0.9431</b>	<b>\$4.6218</b>	<b>\$8.1024</b>	<b>\$7.9933</b>	<b>\$3.0993</b>	<b>\$0.6265</b>	<b>-\$0.0352</b>	<b>\$0.0579</b>	<b>\$0.0900</b>	<b>\$0.1030</b>	<b>-\$0.0452</b>	<b>\$0.1491</b>	<b>\$2.1132</b>
<b>AVERAGE FIXED COST</b>	\$/Dth													\$4,7453
<b>AVERAGE COST AT 100% LOAD FACTOR</b>	\$/Dth													<b>\$0.1560</b>
<b>TOTAL PATH COST</b>	\$/Dth													<b>\$2.2692</b>

REDACTED

2018 - 2019 GCR PROJECTED PRICES

August 1, 2018

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS

UNIT PRICES

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19
<b>PIPELINE FIXED COST UNIT PRICES \$/Dth</b>												
ALGONQUIN AFT-EA/FT-1 DEMAND	\$/Dth	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734
ALGONQUIN AFT-3 DEMAND	\$/Dth	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734	\$6.5734
ALGONQUIN AFT-ES/S DEMAND	\$/Dth	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294	\$2.6294
ALGONQUIN AIM DEMAND	\$/Dth	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862	\$41.7862
ALGONQUIN AFT-CLMS DEMAND (Crary St)	\$/Dth	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375	\$2.7375
COLUMBIA FTS DEMAND	\$/Dth	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870	\$6.2870
DOMINION FTNN DEMAND	\$/Dth	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743	\$4.1743
IROQUOIS DEMAND	\$/Dth	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997	\$5.5997
MILLENNIUM DEMAND	\$/Dth	\$19.4970	\$20.1469	\$18.1972	\$20.1469	\$19.4970	\$20.1469	\$19.4970	\$20.1469	\$20.1469	\$19.4970	\$20.1469
PORTLAND NATURAL GAS DEMAND	\$/Dth	\$24.0000	\$24.8000	\$22.4000	\$24.8000	\$24.0000	\$24.8000	\$24.0000	\$24.8000	\$24.0000	\$24.8000	\$24.0000
TENNESSEE FT-A DEMAND ZONE 0 TO 6	\$/Dth	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222
TENNESSEE FT-A DEMAND ZONE 1 TO 6	\$/Dth	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222	\$21.5222
TENNESSEE FT-A DEMAND ZONE 0 TO 6	\$/Dth	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217
TENNESSEE FT-A DEMAND ZONE 1 TO 6	\$/Dth	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217	\$21.4217
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	\$/Dth	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581	\$22.7581
TENNESSEE FT-A DEMAND ZONE 5 TO 6	\$/Dth	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569	\$7.1569
TENNESSEE FT-A DEMAND DRACUT	\$/Dth	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453
TENNESSEE FT-A DEMAND EVERETT	\$/Dth	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453	\$4.7453
TEXAS EASTERN CDS STX DEMAND M3	\$/Dth	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050	\$6.8050
TEXAS EASTERN CDS WLA DEMAND M3	\$/Dth	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260	\$2.8260
TEXAS EASTERN CDS ELA DEMAND M3	\$/Dth	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750	\$2.3750
TEXAS EASTERN CDS ETX DEMAND M3	\$/Dth	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890	\$2.1890
TEXAS EASTERN CDS T-3 DEMAND M3	\$/Dth	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480	\$10.6480
TEXAS EASTERN FTS DEMAND	\$/Dth	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510	\$5.3510
TEXAS EASTERN SCT STX DEMAND M3	\$/Dth	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220	\$2.7220
TEXAS EASTERN SCT WLA DEMAND M3	\$/Dth	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310	\$1.1310
TEXAS EASTERN SCT ELA DEMAND M3	\$/Dth	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500	\$0.9500
TEXAS EASTERN SCT ETX DEMAND M3	\$/Dth	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760	\$0.8760
TEXAS EASTERN SCT 1-3 DEMAND M3	\$/Dth	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640	\$4.2640
TRANSCANADA TO WASHINGTON DEMAND	\$/Dth	\$11.2311	\$11.6055	\$10.4824	\$11.6055	\$11.2311	\$11.6055	\$11.2311	\$11.6055	\$11.2311	\$11.6055	\$11.2311
TRANSCANADA TO EAST HEREFORD DEMAND	\$/Dth	\$18.5634	\$19.1822	\$17.3258	\$19.1822	\$18.5634	\$19.1822	\$18.5634	\$19.1822	\$18.5634	\$19.1822	\$18.5634
TRANSCONTINENTAL DEMAND	\$/Dth	\$3.9096	\$4.0399	\$3.6490	\$4.0399	\$3.9096	\$4.0399	\$3.9096	\$4.0399	\$3.9096	\$4.0399	\$3.9096
UNION DEMAND	\$/Dth	\$2.9790	\$3.0783	\$2.7804	\$3.0783	\$2.9790	\$3.0783	\$2.9790	\$3.0783	\$2.9790	\$3.0783	\$2.9790

**August 1, 2018**

[illegible]

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS 2018 - 2019 GCR PROJECTED PRICES

August 1, 2018

	UNIT PRICES											
	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19
<b>PIPELINE FIXED COST DOLLARS</b>												
ALGONQUIN AFT-E/AFT-1 DEMAND	\$ 573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759	\$573,759
ALGONQUIN AFT-3 DEMAND	\$ 772,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722	\$72,722
ALGONQUIN AFT-ES/TS DEMAND	\$ 10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725	\$10,725
ALGONQUIN AIM DEMAND	\$ 752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152	\$752,152
ALGONQUIN AFT-CLMS DEMAND (Cray SI)	\$ 262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800	\$262,800
COLUMBIA FTS DEMAND	\$ 298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350	\$298,350
DOMINION FTNN DEMAND	\$ 22,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242	\$2,242
IROQUOIS DEMAND	\$ 5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667	\$5,667
MILLENNIUM DEMAND	\$ 175,473	\$181,322	\$181,322	\$163,775	\$181,322	\$175,473	\$181,322	\$175,473	\$181,322	\$181,322	\$175,473	\$181,322
PORTLAND NATURAL GAS DEMAND	\$ 258,168	\$266,774	\$266,774	\$240,957	\$266,774	\$258,168	\$266,774	\$258,168	\$266,774	\$266,774	\$258,168	\$266,774
TENNESSEE FT-A DEMAND ZONE 0 TO 6	\$ 75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328	\$75,328
TENNESSEE FT-A DEMAND ZONE 1 TO 6	\$ 139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894	\$139,894
TENNESSEE FT-A DEMAND ZONE 0 TO 6	\$ 129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001	\$129,001
TENNESSEE FT-A DEMAND ZONE 1 TO 6	\$ 285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187	\$285,187
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	\$ 263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994	\$263,994
TENNESSEE FT-A DEMAND DRACUT	\$ 14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793	\$14,793
TENNESSEE FT-A DEMAND EVERETT	\$ 137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614	\$137,614
TENNESSEE FT-A DEMAND WADSWORTH	\$ 118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633	\$118,633
TEXAS EASTERN CDS STX DEMAND M3	\$ 94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208	\$94,208
TEXAS EASTERN CDS WLA DEMAND M3	\$ 44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413	\$44,413
TEXAS EASTERN CDS ELA DEMAND M3	\$ 56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425	\$56,425
TEXAS EASTERN CDS ETX DEMAND M3	\$ 17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501
TEXAS EASTERN CDS T-3 DEMAND M3	\$ 489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105	\$489,105
TEXAS EASTERN FTS DEMAND	\$ 2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873	\$2,873
TEXAS EASTERN SCT STX DEMAND M3	\$ 1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554	\$1,554
TEXAS EASTERN SCT WLA DEMAND M3	\$ 733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733	\$733
TEXAS EASTERN SCT ELA DEMAND M3	\$ 1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124	\$1,124
TEXAS EASTERN SCT ETX DEMAND M3	\$ 288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288	\$288
TEXAS EASTERN SCT 1-3 DEMAND M3	\$ 8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950	\$8,950
TRANSCANADA TO WASHINGTON DEMAND	\$ 11,366	\$11,745	\$11,745	\$10,608	\$11,745	\$11,366	\$11,745	\$11,366	\$11,745	\$11,745	\$11,366	\$11,745
TRANSCANADA TO EAST HEREFORD DEMAND	\$ 202,527	\$209,278	\$209,278	\$189,025	\$209,278	\$202,527	\$209,278	\$202,527	\$209,278	\$209,278	\$202,527	\$209,278
TRANSCONTINENTAL DEMAND	\$ 4,848	\$5,010	\$5,010	\$4,525	\$5,010	\$4,848	\$5,010	\$4,848	\$5,010	\$5,010	\$4,848	\$5,010
UNION DEMAND	\$ 335,933	\$37,130	\$37,130	\$33,537	\$37,130	\$35,933	\$37,130	\$35,933	\$37,130	\$37,130	\$35,933	\$37,130
WESTERLY LATERAL (Yankee)	\$											

<b>PIPELINE ALLOCATED TO PEAKING</b>												
TENNESSEE FT-A DEMAND DRACUT	\$ (\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)	(\$81,382)
TENNESSEE FT-A DEMAND EVERETT	\$ (\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)	(\$118,633)
	\$ (\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)	(\$200,014)

TOTAL PIPELINE FIXED DEMAND CHARGES

TOTAL DEMAND UNITS DTH	5,243,415	5,447,382	5,447,382	4,920,216	5,447,382	5,243,415	5,389,009	4,759,710	4,918,367	4,918,367	4,759,710	5,389,009
100% LOAD FACTOR UNIT VALUE \$/DTH												
Average rate per unit per month												
AVERAGE SYSTEM VARIABLE UNIT VALUE \$/DTH												

Marketer Reconciliation 2016/17												
Marketer Demand Units DTH	1,007,610	1,041,197	1,041,197	940,436	1,041,197	1,007,610	1,041,197	1,007,610	1,041,197	1,041,197	1,007,610	1,041,197
100% LOAD FACTOR UNIT VALUE \$/DTH												

TOTAL AVERAGE SYSTEM UNIT VALUE \$/DTH

\$0.7693

(\$24,654)  
12,259,255  
(\$0.0020)

61,883,364

Natural Gas Supply V.S. Requirements													Units: DTH	
	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	OCT 2019	TOTAL	
2018 Estimated GCR														
Normal Weather Scenario														
Forecast Demand														
RI Sales Demand GCR	2,688,486	4,596,563	5,536,758	4,759,103	3,954,964	2,142,275	1,253,992	800,356	629,551	635,180	803,591	1,631,539	29,432,358	
Storage Injections														
TENNESSEE FSMA 501	0	0	0	0	0	0	86,478	13,157	86,478	86,478	86,478	86,478	445,545	
DOMINION GSS 300170	0	0	0	0	0	0	59,184	59,184	59,184	59,184	59,184	59,184	355,103	
DOMINION GSS 300168	0	0	0	0	0	7,627	22,007	22,007	22,007	21,856	21,151	21,856	138,510	
DOMINION GSS 300171	0	0	0	0	0	22,743	26,973	26,973	26,973	26,783	25,919	26,783	183,150	
DOMINION GSSTE 600045	0	0	0	0	0	0	8,350	36,903	0	0	168,457	168,457	382,166	
TETCO FSS-1 400515	0	0	0	0	0	6,392	8,091	8,091	8,091	8,091	8,091	8,091	54,941	
TETCO SS-1 400221	0	0	0	0	0	134,078	169,719	169,719	169,719	169,719	169,719	169,719	1,152,392	
TETCO SS-1 400185	0	0	0	0	0	5,867	7,427	7,427	7,427	7,427	7,427	7,427	50,430	
DOMINION GSS 300169	0	0	0	0	0	24,828	29,443	29,443	29,443	29,234	28,291	29,234	199,917	
COLUMBIA FSS 9630	0	0	0	0	0	0	40,791	34,673	40,791	40,791	26,514	14,277	197,838	
TENNESSEE 62918	0	0	0	0	0	23,700	30,000	30,000	30,000	30,000	30,000	30,000	203,700	
Total Storage Injections	0	0	0	0	0	225,236	488,464	437,577	480,114	479,564	631,231	621,506	3,363,692	
LNG PROVIDENCE	0	97,399	0	47,172	57,063	150,000	155,000	133,546	20,067	0	90,000	11,011	761,257	
LNG EXETER	0	53,519	0	12,665	32,183	30,000	31,000	46,454	12,000	0	90,000	6,175	313,996	
Total LNG Injections	0	150,918	0	59,837	89,246	180,000	186,000	180,000	32,067	0	180,000	17,187	1,075,253	
Total Injections	0	150,918	0	59,837	89,246	405,236	674,464	617,577	512,180	479,564	811,231	638,693	4,438,946	
Delivered Firm Sales Supply														
Sources of Supply													GCR Total	
TENNESSEE ZONE 4 CXN	348,000	359,600	359,600	324,800	359,600	195,557	305,798	170,587	211,916	212,215	243,612	359,600	3,450,885	
TENNESSEE ZONE 4	223,511	418,267	536,092	485,968	296,481	0	0	0	0	0	0	20,439	1,980,757	
TENNESSEE NIAGARA	31,409	31,061	18,275	15,344	29,853	32,010	33,077	32,010	33,077	33,077	32,010	33,077	354,280	
TENNESSEE DRACUT	0	8,970	38,875	16,491	0	0	0	0	0	0	0	0	64,336	
TETCO M2	770,348	796,550	796,367	719,620	798,005	780,725	804,428	688,926	512,145	516,124	407,905	802,427	8,393,569	
TETCO M3	524,853	84,328	183,132	143,109	79,927	608,684	192,483	30,000	30,424	30,943	442,884	618,265	2,969,031	
COLUMBIA MAUMEE	232,075	847,977	861,084	774,484	793,538	192,228	15,388	0	39,168	37,545	0	33,851	3,827,337	
COLUMBIA BROADRUN	90,317	308,107	308,107	278,403	278,403	53,342	0	0	1,623	3,246	0	0	1,321,549	
COLUMBIA EAGLE/PENNSBURG	21,224	76,385	148,816	125,952	53,941	4,052	61,941	34,673	0	0	26,514	59,645	613,142	
DOMINION SOUTH POINT	0	0	15,730	0	0	0	0	0	0	0	0	0	15,730	
TRANSCO LEIDY	2,160	35,634	38,025	34,356	24,179	2,160	1,794	2,160	2,232	2,232	2,160	2,232	149,324	
TETCO LEIDY	0	14,874	206	14,348	6,377	0	0	0	0	0	0	0	35,804	
TETCO to B&W SCT	0	57,671	62,970	56,673	25,188	0	0	0	0	0	0	0	202,502	
ALGONQUIN - AIM	34,114	45,151	86,509	78,963	28,461	12,470	1,217	0	0	0	0	4,693	291,578	
MILLENNIUM	267,432	275,965	273,364	249,379	276,098	263,958	256,141	232,945	230,893	231,175	233,105	264,411	3,054,867	
DAWN TO WADDINGTON	3,006	31,026	30,978	27,997	11,007	30,000	31,000	30,000	31,000	31,000	30,000	31,000	318,014	
DAWN TO EAST HEREFORD	18,480	171,016	268,264	225,560	96,910	113,808	22,002	0	0	0	0	6,219	922,258	
ENGIE - AGT	0	88,780	164,148	193,935	27,598	0	0	0	0	0	0	0	474,461	
ENGIE - EVERETT	0	0	0	0	0	0	0	0	0	0	0	0	0	
ENGIE LNG Refill - Winter	0	150,918	0	59,836	89,246	0	0	0	0	0	0	0	300,000	
ENGIE LNG Refill - Summer	0	0	0	0	0	180,000	186,000	180,000	32,067	0	180,000	17,187	775,253	
PORTABLE LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	
Non LNG Liquid take	2,566,928	3,651,361	4,190,540	3,765,383	3,185,565	2,288,993	1,725,270	1,221,301	1,092,478	1,097,557	1,418,190	2,235,858	28,439,424	
LNG Liquid take	0	150,918	0	59,836	89,246	180,000	186,000	180,000	32,067	0	180,000	17,187	1,075,253	
Total take	2,566,928	3,802,279	4,190,540	3,825,219	3,274,811	2,468,993	1,911,270	1,401,301	1,124,545	1,097,557	1,598,190	2,253,045	29,514,678	

Natural Gas Supply VS. Requirements													Units: DTH
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
Storage Withdrawals													
TENNESSEE FSMA 501	16,542	141,779	99,741	36,473	145,486	0	0	0	0	0	0	0	440,020
DOMINION GSS 300170	0	92,131	112,160	104,979	34,591	0	0	0	0	0	0	0	343,861
DOMINION GSS 300168	5,535	33,447	35,974	35,919	25,918	0	0	0	0	0	0	0	136,793
DOMINION GSS 300171	0	29,600	68,215	58,699	22,353	0	0	0	0	0	0	0	178,867
DOMINION GSSTE 600045	61,743	63,692	63,692	57,551	63,717	61,886	0	0	0	0	0	0	372,281
TETCO FSS-1 400515	0	13,664	13,664	13,669	12,029	0	0	0	0	0	0	0	53,026
TETCO SS-1 400221	0	288,307	288,307	288,776	254,123	0	0	0	0	0	0	0	1,119,512
TETCO SS-1 400185	0	12,617	12,617	12,637	11,121	0	0	0	0	0	0	0	48,991
DOMINION GSS 300169	0	49,335	53,973	51,275	39,356	0	0	0	0	0	0	0	193,938
COLUMBIA FSS 9630	4,982	36,454	69,466	55,595	26,413	0	0	0	0	0	0	0	192,909
TENNESSEE 62918	0	29,251	48,733	90,533	32,657	0	0	0	0	0	0	0	201,174
LNG PROVIDENCE	26,781	90,785	352,780	145,445	69,452	10,656	11,011	10,656	11,011	11,011	10,656	11,011	761,257
LNG EXETER	5,976	64,141	126,898	42,169	32,183	5,976	6,175	5,976	6,175	6,175	5,976	6,175	313,996
Total Withdrawal Delivered	121,558	945,202	1,346,218	993,720	769,399	78,519	17,187	16,632	17,187	17,187	16,632	17,187	4,356,626
Total Storage Withdrawal	88,801	790,276	866,540	806,106	667,763	61,886	0	0	0	0	0	0	3,281,373
Total Peaking Withdrawal	32,757	154,926	479,678	187,614	101,636	16,632	17,187	16,632	17,187	17,187	16,632	17,187	1,075,253
Total Supply	2,688,486	4,596,563	5,536,758	4,759,103	3,954,964	2,367,511	1,742,456	1,237,933	1,109,665	1,114,744	1,434,822	2,253,045	32,796,050
Storage withdrawals at Storage Facility													
TENNESSEE FSMA 501	16,749	143,559	100,994	36,931	147,312	0	0	0	0	0	0	0	445,545
DOMINION GSS 300170	0	95,143	115,827	108,411	35,722	0	0	0	0	0	0	0	355,103
DOMINION GSS 300168	5,604	33,867	36,426	36,370	26,243	0	0	0	0	0	0	0	138,510
DOMINION GSS 300171	0	30,314	69,861	60,091	22,883	0	0	0	0	0	0	0	183,150
DOMINION GSSTE 600045	63,343	65,454	65,454	59,120	65,454	63,343	0	0	0	0	0	0	382,166
TETCO FSS-1 400515	0	14,160	14,160	14,160	12,461	0	0	0	0	0	0	0	54,941
TETCO SS-1 400221	0	297,008	297,008	297,008	261,367	0	0	0	0	0	0	0	1,152,392
TETCO SS-1 400185	0	12,998	12,998	12,998	11,438	0	0	0	0	0	0	0	50,430
DOMINION GSS 300169	0	50,866	55,647	52,844	40,561	0	0	0	0	0	0	0	199,917
COLUMBIA FSS 9630	5,090	37,396	71,260	57,008	27,084	0	0	0	0	0	0	0	197,838
TENNESSEE 62918	90,786	810,383	888,979	826,611	683,592	63,343	0	0	0	0	0	0	203,700
													3,363,693

08/02/2018 NYMEX

<b>\$2,857</b>	<b>\$2,958</b>	<b>\$3,043</b>	<b>\$3,006</b>	<b>\$2,903</b>	<b>\$2,605</b>	<b>\$2,578</b>	<b>\$2,608</b>	<b>\$2,642</b>	<b>\$2,648</b>	<b>\$2,629</b>	<b>\$2,645</b>
----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------

TENNESSEE ZONE 4 CONNEXION

Basis	(\$0.243)	(\$0.245)	(\$0.246)	(\$0.245)	(\$0.244)	(\$0.127)	(\$0.210)	(\$0.228)	(\$0.265)	(\$0.272)	(\$0.369)	(\$0.347)
Usage to Zn 6	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131	\$0.0131
Fuel to Zn 6	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%
Total Delivered	\$2.6599	\$2.7602	\$2.8452	\$2.8068	\$2.7055	\$2.5222	\$2.4108	\$2.4230	\$2.4199	\$2.4189	\$2.3015	\$2.3400

TENNESSEE ZONE 4

Basis	(\$0.243)	(\$0.245)	(\$0.246)	(\$0.245)	(\$0.244)	(\$0.127)	(\$0.210)	(\$0.228)	(\$0.265)	(\$0.272)	(\$0.369)	(\$0.347)
Usage to Zn 6	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181	\$0.1181
Fuel to Zn 6	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%	1.24%
Total Delivered	\$2.7649	\$2.8652	\$2.9502	\$2.9138	\$2.8105	\$2.6272	\$2.5158	\$2.5280	\$2.5249	\$2.5239	\$2.4065	\$2.4450

	Natural Gas Supply VS. Requirements											TOTAL
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
National Grid												
2018 Estimated GCR												
Normal Weather Scenario												
Units: DTH												
<b>TENNESSEE NIAGARA</b>												
Basis												
Tenn usage	(\$0.275)	(\$0.229)	(\$0.135)	(\$0.121)	(\$0.236)	(\$0.447)	(\$0.536)	(\$0.519)	(\$0.565)	(\$0.595)	(\$0.584)	(\$0.599)
Tenn Fuel	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891	\$0.0891
Total Delivered	\$2.6948	\$2.8432	\$3.0238	\$3.0006	\$2.7806	\$2.2669	\$2.1499	\$2.1973	\$2.1852	\$2.1610	\$2.1529	\$2.1539
<b>TENNESSEE DRACUT</b>												
Basis												
Usage	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363	\$0.0363
Fuel	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Total Delivered												
<b>TETCO M2</b>												
Basis												
Usage on Tetco	(\$0.365)	(\$0.350)	(\$0.290)	(\$0.285)	(\$0.327)	(\$0.383)	(\$0.480)	(\$0.495)	(\$0.515)	(\$0.502)	(\$0.597)	(\$0.587)
Usage on AGT	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512	\$0.0512
Fuel on Tetco	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125
Fuel on AGT	1.82%	2.40%	2.40%	2.40%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%
Total Delivered	\$2.6196	\$2.7656	\$2.9158	\$2.8814	\$2.7313	\$2.3427	\$2.2156	\$2.2310	\$2.2453	\$2.2648	\$2.1479	\$2.1746
<b>TETCO M3</b>												
Basis												
Usage on AGT	(\$0.170)	\$0.500	\$2.680	\$2.580	\$0.215	(\$0.205)	(\$0.312)	(\$0.335)	(\$0.328)	(\$0.340)	(\$0.510)	(\$0.457)
Fuel on AGT	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125
Total Delivered	\$2.7179	\$3.5083	\$5.7980	\$5.6572	\$3.1633	\$2.4289	\$2.2940	\$2.3011	\$2.3423	\$2.3363	\$2.1460	\$2.2155
<b>COLUMBIA MAUMEE</b>												
Basis												
Usage on Columbia	(\$0.203)	(\$0.212)	(\$0.220)	(\$0.220)	(\$0.267)	(\$0.237)	(\$0.290)	(\$0.322)	(\$0.395)	(\$0.432)	(\$0.455)	(\$0.440)
Usage on AGT	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202
Fuel on Columbia	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125
Fuel on AGT	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%
Total Delivered	\$2.7444	\$2.8499	\$2.9288	\$2.8897	\$2.7359	\$2.4522	\$2.3705	\$2.3684	\$2.3286	\$2.2969	\$2.2540	\$2.2857
<b>COLUMBIA BROADRUN</b>												
Basis												
Usage on Columbia	(\$0.203)	(\$0.212)	(\$0.220)	(\$0.220)	(\$0.267)	(\$0.237)	(\$0.290)	(\$0.322)	(\$0.395)	(\$0.432)	(\$0.455)	(\$0.440)
Usage on AGT	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202
Fuel on Columbia	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125
Fuel on AGT	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%
Total Delivered	\$2.7444	\$2.8499	\$2.9288	\$2.8897	\$2.7359	\$2.4522	\$2.3705	\$2.3684	\$2.3286	\$2.2969	\$2.2540	\$2.2857

National Grid 2018 Estimated GCR Normal Weather Scenario		Natural Gas Supply VS. Requirements												Units: DTH	
		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL	
<b>COLUMBIA EAGLE/PENNSBURG</b>															
Basis		(\$0.170)	\$0.500	\$2.680	\$2.580	\$0.215	(\$0.205)	(\$0.312)	(\$0.335)	(\$0.328)	(\$0.340)	(\$0.510)	(\$0.457)		
Usage on Columbia		\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202	\$0.0202		
Usage on AGT		\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125	\$0.0125		
Fuel on Columbia		1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%	1.454%		
Fuel on AGT		0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%		
Total Delivered		\$2.7782	\$3.5803	\$5.9038	\$5.7609	\$3.2302	\$2.4849	\$2.3480	\$2.3552	\$2.3971	\$2.3909	\$2.1978	\$2.2683		
<b>DOMINION SOUTH POINT</b>															
Basis		(\$0.367)	(\$0.365)	(\$0.363)	(\$0.360)	(\$0.357)	(\$0.360)	(\$0.442)	(\$0.465)	(\$0.498)	(\$0.505)	(\$0.600)	(\$0.580)		
Usage on Dominion		\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170	\$0.0170		
Usage on Tetco		\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013		
Usage on AGT		\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286		
Fuel on Dominion		1.95%	1.95%	1.95%	1.95%	1.95%	1.95%	1.95%	1.95%	1.95%	1.95%	1.95%	1.95%		
Fuel on Tetco		1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%		
Fuel on AGT		0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%		
Total Delivered		\$2.8376	\$2.9557	\$3.0466	\$3.0099	\$2.9055	\$2.5827	\$2.4693	\$2.4766	\$2.4776	\$2.4766	\$2.3580	\$2.3954		
<b>TRANSCO LEIDY</b>															
Basis		(\$0.375)	(\$0.378)	(\$0.425)	(\$0.425)	(\$0.417)	(\$0.400)	(\$0.512)	(\$0.558)	(\$0.562)	(\$0.580)	(\$0.660)	(\$0.623)		
Usage on Transco		\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073	\$0.0073		
Usage on AGT		\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286		
Fuel on Transco		0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%		
Fuel on AGT		0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%		
Total Delivered		\$2.7487	\$2.8585	\$2.8971	\$2.8585	\$2.7619	\$2.4683	\$2.3275	\$2.3114	\$2.3417	\$2.3296	\$2.2293	\$2.2830		
<b>TETCO LEIDY</b>															
Basis		(\$0.261)	(\$0.348)	(\$0.279)	(\$0.320)	(\$0.321)	(\$0.260)	(\$0.446)	(\$0.395)	(\$0.462)	(\$0.425)	(\$0.590)	(\$0.527)		
Usage on Tetco		\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013	\$0.0013		
Usage on AGT		\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286		
Fuel on Tetco		1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%		
Fuel on AGT		0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%		
Total Delivered		\$2.8778	\$2.9029	\$3.0606	\$2.9796	\$2.8731	\$2.6218	\$2.4046	\$2.4872	\$2.4535	\$2.4974	\$2.3097	\$2.3903		
<b>TETCO to B&amp;W SCT</b>															
Basis		(\$0.365)	(\$0.350)	(\$0.290)	(\$0.285)	(\$0.327)	(\$0.383)	(\$0.480)	(\$0.495)	(\$0.515)	(\$0.502)	(\$0.597)	(\$0.587)		
Usage on Tetco		\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404	\$0.3404		
Usage on AGT		\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286	\$0.2286		
Fuel to M3		1.82%	2.40%	2.40%	2.40%	2.40%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%	1.82%		
Fuel on AGT		0.68%	1.08%	1.08%	1.04%	1.04%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%	0.68%		
Total Delivered		\$3.1269	\$3.2740	\$3.4242	\$3.3898	\$3.2397	\$2.8500	\$2.7229	\$2.7382	\$2.7526	\$2.7721	\$2.6552	\$2.6818		

[illegible]

National Grid 2018 Estimated GCR Normal Weather Scenario		Natural Gas Supply VS. Requirements										Units: DTH			
NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL			
Total Delivered to the City Gate Gas Supply Costs															
TENNESSEE ZONE 4 CONNEXION															
Delivered MMBtu	348,000	359,600	359,600	324,800	359,600	195,557	305,798	170,587	211,916	212,215	243,612	359,600			
Delivered Price	\$2,6599	\$2,7602	\$2,8452	\$2,8088	\$2,7055	\$2,5222	\$2,4108	\$2,4230	\$2,4199	\$2,4189	\$2,3015	\$2,3400			
Total Delivered Cost	\$925,652	\$992,555	\$1,023,140	\$912,287	\$972,893	\$493,237	\$737,227	\$413,329	\$512,824	\$513,334	\$560,667	\$841,447			
TENNESSEE ZONE 4															
Delivered MMBtu	223,511	418,267	536,092	485,968	296,481	0	0	0	0	0	0	20,439			
Delivered Price	\$2,7649	\$2,8652	\$2,9502	\$2,9138	\$2,8105	\$2,6272	\$2,5158	\$2,5280	\$2,5249	\$2,5239	\$2,4065	\$2,4450			
Total Delivered Cost	\$617,991	\$1,198,403	\$1,581,587	\$1,415,997	\$833,254	\$0	\$0	\$0	\$0	\$0	\$0	\$49,971			
TENNESSEE NIAGARA															
Delivered MMBtu	31,409	31,061	18,275	15,344	29,853	32,010	33,077	32,010	33,077	33,077	32,010	33,077			
Delivered Price	\$2,6948	\$2,8432	\$3,0238	\$3,0006	\$2,7806	\$2,2669	\$2,1499	\$2,1973	\$2,1852	\$2,1610	\$2,1529	\$2,1539			
Total Delivered Cost	\$84,641	\$88,311	\$55,260	\$46,041	\$83,009	\$72,564	\$71,111	\$70,335	\$72,279	\$71,478	\$68,914	\$71,244			
TENNESSEE DRACUT															
Delivered MMBtu	0	8,970	38,875	16,491	0	0	0	0	0	0	0	0			
Delivered Price															
Total Delivered Cost															
TETCO M2															
Delivered MMBtu	770,348	796,550	796,367	719,620	798,005	780,725	804,428	688,926	512,145	516,124	407,905	802,427			
Delivered Price	\$2,6196	\$2,7656	\$2,9158	\$2,8814	\$2,7313	\$2,3427	\$2,2156	\$2,2310	\$2,2453	\$2,2648	\$2,1479	\$2,1746			
Total Delivered Cost	\$2,018,021	\$2,202,910	\$2,322,008	\$2,073,547	\$2,179,606	\$1,829,032	\$1,782,268	\$1,536,963	\$1,149,926	\$1,168,915	\$876,134	\$1,744,920			
TETCO M3															
Delivered MMBtu	524,853	84,328	183,132	143,109	79,927	608,684	192,483	30,000	30,424	30,943	442,884	618,265			
Delivered Price	\$2,7179	\$3,5083	\$5,7980	\$5,6572	\$3,1633	\$2,4289	\$2,2940	\$2,3011	\$2,3423	\$2,3363	\$2,1460	\$2,2155			
Total Delivered Cost	\$1,426,496	\$295,843	\$1,061,795	\$809,599	\$252,829	\$1,478,451	\$441,559	\$69,032	\$71,263	\$72,292	\$950,432	\$1,369,754			
COLUMBIA MAUMEE															
Delivered MMBtu	232,075	847,977	861,084	774,484	793,538	192,228	15,388	0	39,168	37,545	0	33,851			
Delivered Price	\$2,7444	\$2,8499	\$2,9288	\$2,8897	\$2,7359	\$2,4522	\$2,3705	\$2,3684	\$2,3286	\$2,2969	\$2,2540	\$2,2857			
Total Delivered Cost	\$636,915	\$2,416,615	\$2,521,984	\$2,238,050	\$2,171,054	\$471,387	\$36,476	\$0	\$91,207	\$86,238	\$0	\$77,372			

	Natural Gas Supply VS. Requirements												Units: DTH	JUL	AUG	SEP	OCT	TOTAL
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT						
National Grid 2018 Estimated GCR Normal Weather Scenario																		
<b>COLUMBIA BROADRUN</b>																		
Delivered MMBtu	90,317	308,107	308,107	278,403	278,403	53,342	0	0	1,623	3,246	0	0	0					
Delivered Price	\$2,7444	\$2,8499	\$2,9288	\$2,8897	\$2,7359	\$2,4522	\$2,3705	\$2,3684	\$2,3286	\$2,2969	\$2,2540	\$2,2857	\$0					
Total Delivered Cost	\$247,869	\$878,062	\$902,399	\$804,509	\$761,687	\$130,808	\$0	\$0	\$3,780	\$7,457	\$0	\$0	\$0					
<b>COLUMBIA EAGLE/PENNSBURG</b>																		
Delivered MMBtu	21,224	76,385	148,816	125,952	53,941	4,052	61,941	34,673	0	0	26,514	59,645	0					
Delivered Price	\$2,7782	\$3,5803	\$5,9038	\$5,7609	\$3,2302	\$2,4849	\$2,3480	\$2,3552	\$2,3971	\$2,3909	\$2,1978	\$2,2683	\$0					
Total Delivered Cost	\$58,963	\$273,476	\$878,575	\$725,595	\$174,239	\$10,068	\$145,439	\$81,660	\$0	\$0	\$58,274	\$135,294	\$0					
<b>DOMINION SOUTH POINT</b>																		
Delivered MMBtu	0	0	15,730	0	0	0	0	0	0	0	0	0	0					
Delivered Price	\$2,8376	\$2,9557	\$3,0466	\$3,0099	\$2,9055	\$2,5827	\$2,4693	\$2,4766	\$2,4776	\$2,4766	\$2,3580	\$2,3954	\$0					
Total Delivered Cost	\$0	\$0	\$47,924	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0					
<b>TRANSCO LEIDY</b>																		
Delivered MMBtu	2,160	35,634	38,025	34,356	24,179	2,160	1,794	2,160	2,232	2,232	2,160	2,232	2,232					
Delivered Price	\$2,7487	\$2,8585	\$2,8971	\$2,8585	\$2,7619	\$2,4683	\$2,3275	\$2,3114	\$2,3417	\$2,3296	\$2,2293	\$2,2830	\$5,096					
Total Delivered Cost	\$5,937	\$101,861	\$110,164	\$98,207	\$66,781	\$5,331	\$4,176	\$4,993	\$5,227	\$5,200	\$4,815	\$5,096	\$0					
<b>TETCO LEIDY</b>																		
Delivered MMBtu	0	14,874	206	14,348	6,377	0	0	0	0	0	0	0	0					
Delivered Price	\$2,8778	\$2,9029	\$3,0606	\$2,9796	\$2,8731	\$2,6218	\$2,4046	\$2,4872	\$2,4535	\$2,4974	\$2,3097	\$2,3903	\$0					
Total Delivered Cost	\$0	\$43,176	\$629	\$42,752	\$18,322	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0					
<b>TETCO to B&amp;W SCT</b>																		
Delivered MMBtu	0	57,671	62,970	56,673	25,188	0	0	0	0	0	0	0	0					
Delivered Price	\$3,1269	\$3,2740	\$3,4242	\$3,3898	\$3,2397	\$2,8500	\$2,7229	\$2,7382	\$2,7526	\$2,7721	\$2,6552	\$2,6818	\$0					
Total Delivered Cost	\$0	\$188,815	\$215,622	\$192,109	\$81,601	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0					
<b>ALGONQUIN - AIM</b>																		
Delivered MMBtu	34,114	45,151	86,509	78,963	28,461	12,470	1,217	0	0	0	0	4,693	0					
Delivered Price	\$2,7412	\$3,5914	\$5,9430	\$5,7785	\$3,2260	\$2,4485	\$2,3119	\$2,3190	\$2,3608	\$2,3547	\$2,1620	\$2,2324	\$0					
Total Delivered Cost	\$93,512	\$162,156	\$514,119	\$456,291	\$91,816	\$30,533	\$2,815	\$0	\$0	\$0	\$0	\$10,477	\$0					
<b>MILLENNIUM</b>																		
Delivered MMBtu	267,432	275,965	273,364	249,379	276,098	263,958	256,141	232,945	230,893	231,175	233,105	264,411	0					
Delivered Price	\$2,5454	\$2,6971	\$2,7336	\$2,6847	\$2,5879	\$2,2663	\$2,1258	\$2,1053	\$2,1402	\$2,1258	\$2,0243	\$2,0817	\$0					
Total Delivered Cost	\$680,708	\$744,293	\$747,271	\$669,498	\$714,516	\$598,220	\$544,510	\$490,420	\$494,152	\$491,436	\$471,867	\$550,427	\$0					

Units: DTH



## 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, 2018 through October 31, 2019

Underground Storage:

Maximum Inventory Level at any time is 100% of MSQ-U

Injections are not allowed.

Minimum Inventory Levels:

November 1	95%
November 15	93%
December 1	91%
December 15	82%
January 1	70%
January 15	61%
February 1	49%
February 15	38%
March 1	28%
March 15	21%
April 1	12%

Peaking Inventory:

Inventory Level allocated on November 1, 2018 = MSQ-P

Injections are not allowed.

Minimum Inventory Levels:

November 1	100%
January 1	92%
February 1	14%
March 1	1%
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



### FT-2 Storage Variable Costs 2018-2019

#### SLF - Weighted Average Loss Factor on Storage Withdrawals

Storage	Withdrawals	Fuel %	Fuel Vol.	Fuel Avg.
TENN 501	445,545	0.00%	0	
GSS 300170	355,103	0.00%	0	
GSS 300168	138,510	0.00%	0	
GSS 300171	183,150	0.00%	0	
GSS-TE 600045	382,166	0.00%	0	
TETCO 400515	54,941	0.46%	253	
TETCO 400221	1,152,392	1.75%	20,167	
TETCO 400185	50,430	1.75%	883	
GSS 300169	199,917	0.00%	0	
COL FSS 9630	197,838	0.00%	0	
TENN 62918	<u>203,700</u>	0.00%	<u>0</u>	
	3,363,693		21,302	<b>0.6333%</b>

#### WWCC - Weighted Average Commodity Cost of Storage Withdrawals

Storage	Withdrawals	Unit Cost	Cost	Average
TENN 501	445,545	\$0.0087	\$3,876	
GSS 300170	355,103	\$0.0167	\$5,930	
GSS 300168	138,510	\$0.0167	\$2,313	
GSS 300171	183,150	\$0.0167	\$3,059	
GSS-TE 600045	382,166	\$0.0210	\$8,025	
TETCO 400515	54,688	\$0.0311	\$1,701	
TETCO 400221	1,132,225	\$0.0489	\$55,366	
TETCO 400185	49,548	\$0.0489	\$2,423	
GSS 300169	199,917	\$0.0167	\$3,339	
COL FSS 9630	197,838	\$0.0153	\$3,027	
TENN 62918	<u>203,700</u>	\$0.0087	<u>\$1,772</u>	
	3,342,390		\$90,831	<b>\$0.0272</b>

#### PLF - Weighted Average Loss Factor on Pipeline Contracts Used to Deliver Storage Withdrawals

Storage	Transported	Fuel %	Fuel Vol.	Fuel Avg.
TENN 501	445,545		1.24%	5,525
GSS 300170	355,103	1.95%	1.24%	11,242
GSS 300168	138,510		1.24%	1,718
GSS 300171	183,150	1.29%	1.08%	4,315
GSS-TE 600045	382,166	1.50%	1.08%	9,798
TETCO 400515	54,688	2.00%	1.08%	1,673
TETCO 400221	1,132,225		1.08%	12,228
TETCO 400185	49,548		1.08%	535
GSS 300169	199,917	1.95%	1.08%	6,015
COL FSS 9630	197,838	1.454%	1.08%	4,982
TENN 62918	<u>203,700</u>		1.24%	<u>2,526</u>
	3,342,390			60,556
				<b>1.8118%</b>

#### PCC - Weighted Average Commodity Cost on Pipeline Contracts Used to Deliver Storage Withdrawals

Storage	Withdrawals	Unit Cost	Cost	Average
TENN 501	440,020		\$0.1181	\$51,966
GSS 300170	343,861	\$0.0170	\$0.1181	\$46,456
GSS 300168	136,793		\$0.1181	\$16,155
GSS 300171	178,867	\$0.0013	\$0.0125	\$2,468
GSS-TE 600045	372,281	\$0.0013	\$0.0125	\$5,137
TETCO 400515	53,026	\$0.0392	\$0.0125	\$2,739
TETCO 400221	1,119,512		\$0.0125	\$13,994
TETCO 400185	48,991		\$0.0125	\$612
GSS 300169	193,938	\$0.0170	\$0.0013	\$5,973
COL FSS 9630	192,909	\$0.0200	\$0.0125	\$6,270
TENN 62918	<u>201,174</u>		\$0.1181	<u>\$23,759</u>
	3,281,373			\$175,530
				<b>\$0.0535</b>



**DIRECT TESTIMONY**

**OF**

**ANN E. LEARY**

**Table of Contents**

I.	Introduction.....	1
II.	GCR Factor Development.....	3
III.	Historical Sales Review .....	15
IV.	Bill Impacts.....	16

1    **I.     Introduction**

2    **Q.     Please state your name and business address.**

3    A.     My name is Ann E. Leary. My business address is 40 Sylvan Road, Waltham,  
4           Massachusetts 02451.

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

7    A.     I am the Manager of New England Gas Pricing for National Grid USA Service Company,  
8           Inc. In this position, I am responsible for preparing and submitting various regulatory  
9           filings with the Rhode Island Public Utilities Commission (PUC) on behalf of The  
10          Narragansett Electric Company d/b/a National Grid (Company), and the Massachusetts  
11          Department of Public Utilities on behalf of Boston Gas Company and Colonial Gas  
12          Company, each d/b/a National Grid.

14   **Q.     Please provide your educational background.**

15   A.     I received a Bachelor of Science in Mechanical Engineering from Cornell University in  
16          1983.

18   **Q.     Please provide your professional background.**

19   A.     In 1985, I joined the Essex County Gas Company (Essex) as a Staff Engineer. In 1987, I  
20          became a planning analyst and later accepted the position of Manager of Rates at Essex.  
21          Following Essex's merger with Eastern Enterprises in 1998, I became Manager of Pricing

1 for Boston Gas Company (Boston). After Boston merged with KeySpan Energy  
2 Delivery, subsequently National Grid, I became the Manager of New England Gas  
3 Pricing, the position I hold today.  
4

5 **Q. Have you previously testified before the PUC?**

6 A. Yes, I have testified before the PUC on numerous occasions, most recently in the  
7 Company's 2017 rate case filing in Docket No. 4770. I also submitted written testimony  
8 in the Company's 2018 Distribution Adjustment Charge (DAC) filing in Docket No.  
9 4846. In addition, I have testified extensively in several ratemaking and regulatory  
10 proceedings before the Massachusetts Department of Public Utilities and the New  
11 Hampshire Public Utilities Commission.  
12

13 **Q. What is the purpose of your testimony?**

14 A. The purpose of my testimony is to propose the Gas Cost Recovery (GCR) factors to  
15 become effective on November 1, 2018 for the following services: (1) firm sales service  
16 to customers in the Residential Non-Heating and Heating rate classes, as well as  
17 Commercial and Industrial (C&I) firm sales customers in the Small, Medium, Large, and  
18 Extra Large rate classes; and (2) transportation services provided to Gas Marketers and  
19 the associated Gas Marketer Fixed Charges and factors.  
20

1 **Q. How is your testimony organized?**

2 A. My testimony is composed of the following four general sections: I. Introduction; II.  
3 GCR Factor Development; III. Historical Sales Adjustment; and IV. Bill Impacts.  
4

5 **Q. Are you including any attachments with your testimony?**

6 A. Yes. I am sponsoring the following attachments that accompany my testimony:

7	Attachment AEL-1	Gas Cost Recovery Factors
8	Attachment AEL-2	Annual GCR Reconciliation Filing
9	Attachment AEL-3	Projected Gas Cost Balances
10	Attachment AEL-4	Bill Impact Analysis
11	Attachment AEL-5	FT-2 Demand Rate
12	Attachment AEL-6	FT-2 Capacity Allocator Percentages
13	Attachment AEL-7	Marketer Reconciliation

14  
15 **II. GCR Factor Development**

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

17 A. The proposed GCR factors reflect the load specific (High Load and Low Load) factors  
18 necessary for the Company to recover the projected gas costs allocated to firm sales  
19 customers for the period November 1, 2018 through October 31, 2019. As shown in the  
20 joint pre-filed direct testimony of Company witnesses Nancy G. Culliford and  
21 Elizabeth D. Arangio on Attachment NGC/EDA-1, firm sales customers' gas costs for the

period are projected to be approximately \$161.4 million for the 12 months ending October 2019. In addition to these projected costs, the GCR factors also include recovery of working capital costs, inventory financing costs, prior period reconciliations, and liquefied natural gas (LNG) operation and maintenance (O&M) costs, as well as credits for FT-2 Market Storage Demand and costs allocated to the Distribution Adjustment Clause factors. The table below summarizes the costs and credits included in the proposed 2018-19 GCR factors:

<b>GCR Component</b>	<b>Amount (millions)</b>	<b>Reference</b>
Firm Gas Costs	\$161.4	NGC/EDA-1
Working Capital Costs	\$1.3	AEL-1, Page 2, Line (9) and Page 3, Line (5)
Inventory Financing Costs	\$0.7	AEL-1, Page 3, Lines (8) and (9)
Prior Period Deferred Balance (Includes the Marketer Fixed Costs Reconciliation)	\$23.4	AEL-1, Page 2, Lines (11) and (12) and Page 3, Line (6)
LNG O&M Costs	\$1.1	AEL-1, Page 2, Line (8) and Page 3, Line (7)
FT-2 Marketer Storage Demand Costs	(\$4.4)	AEL-1, Page 2, Line (4)
Demand Costs Recovered via the DAC Factors	\$0.0	AEL-1, Page 2, Line (5)
Total	\$183.5	AEL-1, Page 2, Line (14) and AEL-1, Page 3, Line (11)

Thus, the proposed GCR factors are intended to recover approximately \$183.5 million in net costs over the period November 2018 through October 2019.

1 **Q. At a high level, please explain how the proposed GCR factors were derived.**

2 A. The proposed GCR factors were developed based upon the fixed and variable cost  
3 components as defined in the GCR clause of the Company's tariff, RIPUC NG-GAS No.  
4 101, Section 2, Gas Charge, Schedule A. Attachment AEL-1 provides a summary of the  
5 GCR fixed and variable gas cost components used to derive the rates for which the  
6 Company seeks approval in this filing.  
7

8 **Q. Are the proposed GCR factors to become effective November 1, 2018 impacted by**  
9 **the Amended Settlement Agreement approved by the PUC on August 24, 2018 in**  
10 **Docket Nos. 4770 and 4780 (2017 Rate Case)?**

11 A. Yes. As a result of the Amended Settlement Agreement in the 2017 Rate Case, the  
12 Company has updated from prior GCR filings the following components of the proposed  
13 GCR factors to become effective November 1, 2018: (1) reduced the uncollectible  
14 percentage used to gross up the GCR factors from 3.18 percent to 1.91 percent; (2)  
15 updated the fixed and variable LNG O&M costs from \$572,581 and \$572,694,  
16 respectively, to \$829,823, and \$302,244, respectively; (3) increased the number of days  
17 lag used to calculate the gas working capital from 21.51 days to 32.92 days; and (4)  
18 updated the weighted average cost of capital and cost of debt from 7.26 percent and  
19 2.58 percent, respectively, to 7.15 percent and 2.42 percent, respectively, used in both the  
20 working capital and inventory finance calculations.  
21

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

2    A.    The fixed cost component includes all of the fixed costs related to the purchase, storage,  
3           and delivery of firm gas for both High Load Factor and Low Load Factor customers. As  
4           shown in Attachment AEL-1, Page 2, the fixed cost component is derived by taking the  
5           total fixed costs, which are already reduced by capacity release credits, less any credits  
6           such as Natural Gas Portfolio Management Plan (NGPMP) customer credits, demand  
7           costs allocated to the DAC mechanism, if any, and storage demand costs billed to FT-2  
8           Marketers. The FT-2 storage demand costs are calculated by multiplying the FT-2  
9           Demand Charge rate by the forecast of storage and peaking maximum daily quantity  
10          (MDQ) to be billed to FT-2 Marketers. Adjustments are also made for supply-related  
11          LNG costs, working capital costs, and prior period deferred fixed gas costs under/over-  
12          recovery balances, including an adjustment for the Marketer fixed cost reconciliation as  
13          stipulated in the Settlement Agreement between the Company and the Division of Public  
14          Utilities and Carriers (Division) in Docket No. 4199. This results in total fixed gas costs  
15          of \$81.3 million to be recovered over the period November 2018 through October 2019.  
16          Finally, because the Company's gas supply resources are planned so that there is  
17          sufficient capacity to meet the needs of firm customers (excluding firm customers with  
18          capacity exempt status) under design winter conditions, the total fixed gas cost to be  
19          recovered from customers is allocated between High Load Factor and Low Load Factor  
20          customers. The allocation is based on the proportion of design winter use of these two  
21          groups of customers. The High Load and Low Load Factors for each group are derived

1 using the allocated fixed gas cost and dividing each amount by each group's projected  
2 throughput for the upcoming year. Accordingly, the proposed GCR fixed Low Load  
3 Factor is \$3.0728 per dekatherm, while the proposed GCR fixed High Load Factor is  
4 \$2.1496 per dekatherm, excluding the adjustment for uncollectible expense.  
5

6 **Q. In the calculation of the fixed cost, you mentioned that the total fixed cost excludes**  
7 **“demand costs allocated to the DAC mechanism, if any.” Is the Company proposing**  
8 **any change to the demand costs allocated to the DAC?**

9 A. Yes. For the factors effective November 1, 2018, the Company is not allocating any  
10 demand costs to the DAC. In Docket No. 4719, the Company and the Division agreed to  
11 allocate 100 percent of the costs associated with the Company's Crary Street Gate Station  
12 to the DAC<sup>1</sup> because the operation of the Crary Street Gate Station, which commenced  
13 on July 17, 2017, eliminated the Company's need to rely on liquefied natural gas (LNG)  
14 to maintain pressure in its distribution system. Therefore, as LNG was no longer required  
15 for system pressure due to the operation of the Crary Street Gate Station, the Company  
16 revised its prior System Pressure calculation<sup>2</sup> to include 100 percent of the costs  
17 associated with the Crary Street Gate Station. However, during a recent discussion  
18 among the Company, the Division, and the Division's consultant, the parties re-examined

---

<sup>1</sup> See the Company's Reply Comments in Docket No. 4719 dated October 23, 2017.

<sup>2</sup> Pursuant to the Settlement Agreement in Docket No. 4339 (the 2012 Settlement Agreement), the Company had allocated 75.77 percent of the annual lease payments for the National Grid LNG (NGLNG) tank to System Pressure.

1       the basis for allocating the costs associated with the Crary Street Gate Station to the  
2       System Pressure factor in the DAC. The parties recognized that all Company gate  
3       stations provide inlet pressure to the Company's distribution system, so it would be  
4       inappropriate to single out the costs of only one gate station (the Crary Street Gate  
5       Station) to assign to System Pressure in the DAC. Therefore, as the underlying intent of  
6       the System Pressure factor was to identify LNG-related costs associated with maintaining  
7       system pressure, and the costs associated with the Crary Street Gate Station were not  
8       LNG-related, the Company and the Division agreed that the Company would no longer  
9       assign costs of the Crary Street Gate Station to the DAC. Instead, the Company would  
10      recover the costs associated with the Crary Street Gate Station through the GCR factors  
11      in the same way it recovers the costs for all other gate stations that serve the Company.  
12      In addition, at the request of the PUC during last year's DAC proceeding in Docket No.  
13      4708, the Company provided further clarification of the costs required to maintain system  
14      pressure to other parts of the Company's distribution system. In a letter to the Division  
15      dated July 30, 2018, the Company explained that it requires only 17,120 dekatherms per  
16      year from its Exeter LNG facility to maintain system pressure in a normal winter at an  
17      estimated annual cost of approximately \$100,000. The Company and the Division agreed  
18      not to reallocate this small amount from the GCR to the DAC because such costs would  
19      result in a factor of less than \$0.0002 per therm, which, for a typical Residential Heating  
20      customer, equates to only a \$0.25 per year reallocation from the GCR factor to the DAC.

1   **Q.     How did the Company derive the 2018-19 throughput forecast used to calculate the**  
2       **High Load and Low Load GCR Factors?**

3   A.     The pre-filed direct testimony of Company witness Theodore E. Poe, Jr. supports the  
4       2018-19 throughput forecast used to derive the GCR factors.

6   **Q.     How did the Company calculate the Marketer fixed cost reconciliation balance?**

7   A.     In accordance with the Settlement Agreement approved in Docket No. 4199, the  
8       Company included an annual reconciliation of Marketer fixed costs. The Company  
9       calculated the Marketer reconciliation by updating the 2017-18 pipeline surcharge/credit  
10      for each path that the Company filed last year and based the update on actual, instead of  
11      projected, pipeline capacity costs. The Company then compared the pipeline  
12      surcharge/credit approved in Docket No. 4719 for each path with the updated actual  
13      pipeline surcharge/credit. The Company multiplied the difference by the Marketer's  
14      actual monthly capacity for the months of November 2017 through July 2018 and  
15      forecasted monthly capacity for the months of August 2018 through October 2018. This  
16      results in a credit to the Marketers of \$17,803, as shown in Attachment AEL-7, Page 1,  
17      Line (22).

18  
19      The Company also finalized the 2016-17 Marketer reconciliation that it filed last year in  
20      Docket No. 4719 to replace the Marketers' forecasted monthly capacity for the months of  
21      August 2017 through October 2017 with their actual monthly capacity. This update

1 results in a Marketer credit of \$21,588 associated with the latter portion of the 2016-17  
2 period. In addition, the Company reconciled the actual revenues of \$29,082 credited to  
3 Marketers during the period November 2017 through October 2018 with the actual 2016-  
4 17 Marketer credit of \$21,588 and the prior period 2016-17 Marketer reconciliation credit  
5 balance of \$14,344. This results in a net Marketer reconciliation credit of \$6,851 for the  
6 2016-17 period, as shown in Attachment AEL-7, Page 2, Line (48). The sum of the  
7 reconciliation amounts shown in Attachment AEL-7 for 2017-18 (Page 1, Line (22)) and  
8 2016-17 (Page 2, Line (48)) is the total Marketer reconciliation amount of \$24,654, as  
9 shown on Page 2, Line (50) and reflected in Attachment AEL-1, Page 2, Line (12).

10  
11 Attachment AEL-7 shows the calculation of the Marketer reconciliation adjustment for  
12 both the 2016-17 and 2017-18 periods. In addition to surcharging firm sales customers'  
13 fixed costs for this amount, the Company included the reconciliation in its calculation of  
14 the 2018-19 pipeline surcharge/credits, as detailed in Ms. Culliford and Ms. Arangio's  
15 joint testimony and as shown in Attachment NGC/EDA-4. The Company has provided  
16 additional detail for monthly capacity release information for each pipeline path in an  
17 Excel file contained in the USB flash drive provided to the Division's consultant, Bruce  
18 Oliver, with this filing.

19

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

2    A.    As done last year in Docket No. 4719, the Company calculated the monthly design sales  
3           forecast by applying a monthly heat factor to the monthly design degree days. The  
4           monthly heat factor was computed by dividing the heating component of the normal sales  
5           (normal sales less monthly base use) by normal degree days for each month during the  
6           period November 2018 through March 2019. To compute the monthly design sales, the  
7           Company summed the monthly base use and the product of the monthly heat factor  
8           multiplied by the monthly design degree days. In Attachment AEL-1, Pages 14 through  
9           16, the Company has provided detailed calculations showing the derivation of the  
10          monthly design sales.

11  
12   **Q.    How was the variable cost component of the proposed GCR factors derived?**

13    A.    The variable cost component includes all variable costs of gas such as commodity costs,  
14           supply-related LNG O&M, working capital, inventory finance costs, pipeline refunds,  
15           and deferred cost balances. As shown in Attachment AEL-1, Page 3, Line (11), the total  
16           estimated variable cost for the period November 2018 through October 2019 is  
17           \$102,211,195. The variable costs are divided by the projected throughput to obtain a  
18           variable cost factor of \$3.8346 per dekatherm.

1   **Q.     What is the Company’s estimate of the deferred gas cost balance at the end of the**  
2       **current GCR period?**

3   A.    Based on actual data through July 2018 and forecasted data for the months of August  
4        through October 2018, the total estimated deferred balance at October 31, 2018 is an  
5        under-recovery of \$23,353,322, as shown in Attachment AEL-1, Page 7. This deferred  
6        balance is incorporated into the development of the proposed GCR factors for the period  
7        November 1, 2018 to October 31, 2019. In addition, the Company shows the projected  
8        monthly deferred gas cost balances for November 2018 through October 2019 in  
9        Attachment AEL-3.

11   **Q.     Is the Company proposing any changes to the deferred gas cost balance for the**  
12       **period April 2017 through March 2018 from the amounts provided in the**  
13       **Company’s annual GCR reconciliation submitted on June 29, 2018?**

14   A.    Yes. The Company has updated the March 31, 2018 deferral balance reflected in the  
15        annual GCR reconciliation report submitted to the PUC on June 29, 2018 to include the  
16        actual costs associated with the leasing of the third party portable LNG equipment and  
17        services in Cumberland. In the Company’s Reply Comments submitted in Docket No.  
18        4719 on October 23, 2017, the Company agreed with the Division’s recommendation to  
19        exclude from its proposed 2017-18 GCR factors the estimated costs associated with  
20        leasing the third party portable LNG equipment and services in Cumberland, and instead  
21        to reflect the actual costs in the annual GCR reconciliation. As a result, the Company has

1 increased the fiscal year 2018 annual GCR reconciliation by \$259,820, from \$42,820,863  
2 to \$43,080,683.  
3

4 **Q. Is the Company proposing to include an estimate of incremental costs associated**  
5 **with the operation of third party portable LNG equipment and services in**  
6 **Cumberland in this year's GCR filing?**

7 A. No. Consistent with the treatment of such costs in Docket No. 4719, the Company will  
8 reflect the actual costs incurred to meet the daily gas supply requirement in the  
9 Cumberland area during the winter season 2018-19 in its fiscal year 2019 annual  
10 reconciliation of GCR costs and revenue.  
11

12 **Q. Attachment AEL-2 provides the fiscal year 2018 Annual GCR Reconciliation**  
13 **balances. Does the monthly information shown in Attachment AEL-2 correspond**  
14 **with the monthly deferred balance reports filed in Docket Nos. 4647 and 4719?**

15 A. The March 31, 2018 reconciliation balance of \$43,080,683 shown in Attachment AEL-2  
16 reflects the adjusted balance from what was submitted on June 29, 2018 in the annual  
17 GCR reconciliation report and is the same balance reflected in the July 2018 monthly  
18 deferred balance report filed in Docket No. 4719 on August 17, 2018.  
19

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

2    A.    Yes. Consistent with the modifications in Docket No. 4270, the Company is submitting  
3           for approval its FT-2 Marketer Demand rate of \$17.0642 per MDQ in dekatherms per  
4           month, as shown in Attachment AEL-5, as well as the storage and peaking charge of  
5           \$0.1648 per therm for FT-1 firm transportation customers returning to Transitional Sale  
6           Service (TSS). The Company is also submitting for approval the capacity assignment  
7           percentages for the High Load and Low Load Factors to be used in the determination of  
8           pipeline, underground storage, and peaking capacity for Marketers. These percentages  
9           are set forth in Attachment AEL-6. The Company has also provided the detail  
10          calculations of the capacity assignment percentages in an Excel file contained in the USB  
11          flash drive provided to Mr. Oliver with this filing.

12  
13   **Q.    How was the proposed FT-2 Marketer Demand rate calculated?**

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

21

1 The FT-2 Demand rate is derived by first totaling the fixed storage costs, associated  
2 inventory finance, working capital charges, and supply-related LNG O&M costs, less any  
3 demand credits assigned to the DAC factors and any refunds, if applicable. That total is  
4 then divided by the total storage and peaking MDQ for the year to derive a monthly per  
5 dekatherm rate to be charged to Marketers. As shown in Attachment AEL-5, the  
6 proposed FT-2 Marketer Demand rate is \$17.0642 per dekatherm and will be applied to  
7 the Marketers' storage and peaking MDQ.

8  
9 **III. Historical Sales Review**

10 **Q. Did the Company report negative monthly sales for the period April 2017 through**  
11 **March 2018?**

12 A. Yes, the Company reported a small amount of negative sales from April 2017 through  
13 March 2018. As shown in Attachment AEL-2, Page 8 of this filing, the Company  
14 reported negative sales for the following customer classes: (1) TSS Large Low Load  
15 Factor customers (Line (16)) during the month of June 2017; (2) Firm Transportation  
16 Service FT-2 Extra Large Low Load Factor customers (Line (47)) during the month of  
17 September 2017; and (3) Firm Sales Residential Non-Heating Low Income customers  
18 (Line (3)) during the month of October 2017. The negative sales totaled 1,505  
19 dekatherms, equating to 0.004 percent of total annual sales.

1 **Q. Has the Company investigated these negative sales?**

2 A. Yes. Billing adjustments caused the negative volumes for the TSS Large Low Load  
3 Factor, the Firm Transportation Service FT-2 Extra Large Low Load Factor, and the Firm  
4 Sales Residential Non-Heating Low Income customer classes.

5  
6 **Q. Please describe the billing adjustments that resulted in negative sales for the TSS**  
7 **Large Low Load Factor, the Firm Transportation Service FT-2 Extra Large Low**  
8 **Load Factor, and the Firm Sales Residential Non-Heating Low Income customers in**  
9 **June 2017, September 2017, and October 2017, respectively.**

10 A. The negative sales reported for the TSS Large Low Load Factor customers in June 2017,  
11 the Firm Transportation Service FT-2 Extra Large Low Load Factor customers in  
12 September 2017, and the Firm Sales Residential Non-Heating Low Income customers in  
13 October 2017 are due to the cancellation and rebilling for customers on a different rate  
14 classification.

15  
16 **IV. Bill Impacts**

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

19 A. A summary of annual bill impacts for customers with various levels of usage is provided  
20 in Attachment AEL-4, reflecting annual bills at current rates in Column (c) calculated  
21 assuming rates in effect during September 2018 are effective for 12 months. An average

1 Residential Heating customer using 845 therms per year will experience a total annual  
2 bill of \$1,322.08 based on the proposed GCR and DAC factors, which is a decrease of  
3 \$91.73, or 6.5 percent, from last year's bills. This overall decrease is comprised of a  
4 decrease of \$40.14 as a result of the proposed GCR factors; a decrease of \$48.84 as a  
5 result of the proposed DAC factors, for which the Company submitted a supplemental  
6 filing on August 31, 2018 in Docket No. 4846; and a decrease of \$2.75 in Gross Earnings  
7 Tax.

8  
9 **Q. Does this conclude your testimony?**

10 **A. Yes.**



**THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESS: ANN E. LEARY  
AUGUST 31, 2018  
ATTACHMENTS**

---

Attachments of Ann E. Leary

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



**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESS: ANN E. LEARY**  
**AUGUST 31, 2018**

---

Attachment AEL-1  
Gas Cost Recovery Factors

**National Grid - RI Gas  
Gas Cost Recovery (GCR) Filing  
Factors Effective November 1, 2018**

Description (a)	Source		High Load <sup>1</sup> (d)	Low Load <sup>2</sup> (e)	FT-2 Mkter <sup>3</sup> (f)
	Reference (b)	Line # (c)			
(1) Fixed Cost Factor - \$/dktherm	AEL-1, pg 2	Line (18)	\$2.1496	\$3.0728	
(2) Variable Cost Factor - \$/dktherm	AEL-1, pg 3	Line (13)	\$3.8346	\$3.8346	
(3) Total Gas Cost Recovery Charge- \$/dktherm	(1) + (2)		\$5.9842	\$6.9074	
(4) Uncollectible %	Docket 4770		1.91%	1.91%	
(5) Total GCR Charge adjusted for Uncollectibles- \$/dkdtherm	(3) ÷ [1 - (4)]		\$6.1007	\$7.0419	
(6) GCR Charge on a per therm basis	(5) ÷ 10		<b>\$0.6100</b>	<b>\$0.7041</b>	
(7) Current rate effective 09/01/18* - \$/therm			\$0.7090	\$0.7516	
(8) Increase / (Decrease) - \$/therm	(6) - (7)		(\$0.0990)	(\$0.0475)	
(9) Percent Decrease	(8) ÷ (7)		-14.0%	-6.3%	

\* Docket No.4770, Revised Compliance Attachment 18

<sup>1</sup> Includes: Residential Non Heating, Large High Load and Extra Large High Load

<sup>2</sup> Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

<sup>3</sup>See AEL-5 for calculation of FT-2 rate

REDACTED

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

	<u>Description</u> (a)	<u>Source</u>		<u>Amount</u> (d)	<u>High Load Factor Total</u> (e)	<u>Low Load Factor Total</u> (f)
		<u>Reference</u> (b)	<u>Line #</u> (c)			
(1)	Fixed Costs (net of Cap Rel to marketers)	AEL-1, pg 5	Line (63)	\$81,074,626		
	Less:					
(2)	NGPMP Customer Benefit	NGC-EDA-1		(\$4,000,000)		
(3)	Interruptible Costs			\$0		
(4)	FT-2 Storage Demand Costs	AEL-5, pg 2	Line (25)	(\$4,448,149)		
(5)	System Pressure to DAC			\$0		
(6)	Refunds			\$0		
(7)	Total Credits	Sum[(2):(6)]		(\$8,448,149)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Dkt 4770	Compliance Attachment 2 Schedule 32 Pg 5	\$829,823		
(9)	Portable LNG Storage Cost			\$0		
(10)	Working Capital Requirement	AEL-1, pg 9	Line (16)	\$614,767		
(11)	Deferred Fixed Cost Under-recovered	AEL-1, pg 7	Line (17)	\$7,218,742		
(12)	Reconciliation Amount from Fixed costs- Marketers	AEL-7, pg 2	Line (50)	\$24,654		
(13)	Total Additions	Sum[(8):(12)]		\$8,687,986		
(14)	Total Fixed Costs	(1) + (7) + (13)		\$81,314,463		
(15)	Design Winter Sales Percentage	AEL-1, pg 13	Lines (10) & (11)		1.70%	98.30%
(16)	Allocated Supply Fixed Costs	(14) x (15)		\$1,379,004		\$79,935,459
(17)	Sales (Dth) Nov 2018 - Oct 2019	AEL-1, pg 12	Line (9)	26,654,839	641,511	26,013,328
(18)	Fixed Factor	(16) ÷ (17)		\$2,1496		\$3,0728

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

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

	<u>Description</u> (a)	<u>Source</u>		
		<u>Reference</u> (b)	<u>Line #</u> (c)	<u>Amount</u> (d)
(1)	Variable Costs, excluding Refunds	AEL-1, pg 6	Line (92) - Line (86)	\$84,383,359
Less:				
(2)	Non-Firm Sales			\$0
(3)	Refunds	AEL-1, pg 6	Line (86)	\$0
(4)	Total Credits	Sum [(2):(3)]		\$0
Plus:				
(5)	Working Capital	AEL-1, pg 9	Line (32)	\$639,856
(6)	Deferred Variable Cost Under-recovered	AEL-1, pg 7	Line (35)	\$16,134,580
(7)	Supply Related LNG O&M	Docket 4770	Compliance Attachment 2 Schedule 32 Pg 5	\$302,244
(8)	Inventory Financing - LNG	AEL-1, pg 11	Line (22)	\$189,030
(9)	Inventory Financing - Storage	AEL-1, pg 11	Line (12)	\$562,126
(10)	Total Additions	Sum [(5):(9)]		\$17,827,836
(11)	Total Variable Supply Costs	(1) + (4) + (10)		\$102,211,195
(12)	Sales (Dt) Nov 2018 - Oct 2019	AEL-1, pg 12	Line (9)	26,654,839
(13)	Variable Cost Factor	(11) ÷ (12)		<b>\$3.8346</b>

Redacted  
Page 4 of 16

REDACTED

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

Description (a)	Reference (b)	Nov-18 (c)	Dec-18 (d)	Jan-19 (e)	Feb-19 (f)	Mar-19 (g)	Apr-19 (h)	May-19 (i)	Jun-19 (j)	Jul-19 (k)	Aug-19 (l)	Sep-19 (m)	Oct-19 (n)	Nov-Oct (o)
<b>STORAGE FIXED COSTS - Delivery</b>														
(38) Algonquin for TETCO SS-1	NGC-EDA-2	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$92,928	\$1,115,138
(39) Algonquin delivery for FSS	NGC-EDA-2	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$6,205	\$74,463
(40) TETCO delivery for FSS	NGC-EDA-2	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$4,885	\$58,622
(41) Algonquin SCT for SS-1	NGC-EDA-2	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$1,749	\$20,983
(42) Algonquin delivery for GSS, GSS-TE	NGC-EDA-2	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$77,165	\$925,982
(43) Algonquin SCT delivery for GSS-TE	NGC-EDA-2	\$492	\$492	\$492	\$492	\$492	\$492	\$492	\$492	\$492	\$492	\$492	\$492	\$5,900
(45) Tennessee delivery for GSS	NGC-EDA-2	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$54,796	\$657,552
(46) Tennessee delivery for FSMA	NGC-EDA-2	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$33,497	\$401,962
(47) TETCO delivery for GSS/GSS-TE	NGC-EDA-2	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$34,123	\$409,480
(48) TETCO delivery for GSS-TE	NGC-EDA-2	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$3,538	\$42,455
(49) TETCO delivery for GSS-TE	NGC-EDA-2	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$34,396	\$412,746
(50) TETCO delivery for GSS Conv	NGC-EDA-2	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$10,676	\$128,112
(51) Dominion delivery for GSS Conv	NGC-EDA-2	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$8,603	\$103,239
(52) Dominion delivery for GSS	NGC-EDA-2	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$22,224	\$266,688
(53) Algonquin delivery for FSS	NGC-EDA-2	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$16,729	\$200,752
(54) Columbia Delivery for FSS	NGC-EDA-2	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$15,593	\$187,119
(55) ENGIE Gas Demand Payment Summer	NGC-EDA-2													
(56) ENGIE Gas Demand Payment Winter Refill	NGC-EDA-2													
(57) Peaking Supply at AGT CITYGATE	NGC-EDA-2													
(58) Peaking Supply at EVERETT	NGC-EDA-2													
(59) Peaking Supply at Dracut	NGC-EDA-2													
(60) Less Credits from Mktcr Releases	NGC-EDA-2													
(61) STORAGE DELIVERY FIXED COST	Suml((38):(60))													
(62) TOTAL STORAGE FIXED	(38) + (61)													
(63) TOTAL FIXED COSTS	(23)+(37)+(61)	\$4,729,063	\$10,471,730	\$10,470,396	\$10,401,565	\$10,470,396	\$4,886,910	\$4,909,854	\$4,933,176	\$4,956,120	\$4,956,120	\$4,933,176	\$4,956,120	\$81,074,626

Redacted  
Page 6 of 16

Source: Docket No.4719 filed on August 17, 2018.

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

Description (a)	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
	<u>fcst</u> (b)	<u>fcst</u> (c)	<u>fcst</u> (d)	<u>fcst</u> (e)	<u>fcst</u> (f)	<u>fcst</u> (g)	<u>fcst</u> (h)	<u>fcst</u> (i)	<u>fcst</u> (j)	<u>fcst</u> (k)	<u>fcst</u> (l)	<u>fcst</u> (m)	<u>Nov-Oct</u> (n)
(1) <u>I. Fixed Cost Revenue</u>													
(2) (a) Low Load dth	1,644,221	3,180,673	4,611,880	4,773,326	4,088,946	2,852,669	1,592,600	831,436	585,836	537,645	599,734	714,361	26,013,328
(3) Fixed Cost Factor	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728	\$3,0728
(4) Low Load Revenue	\$5,052,364	\$9,773,573	\$14,171,386	\$14,667,476	\$12,564,513	\$8,765,683	\$4,893,742	\$2,554,836	\$1,800,158	\$1,652,074	\$1,842,862	\$2,195,088	\$79,933,755
(5) (b) High Load dth	51,593	63,306	78,849	72,957	63,281	60,627	54,566	43,454	36,505	36,007	39,507	40,859	641,511
(6) Fixed Cost Factor	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496	\$2,1496
(7) High Load Revenue	\$110,904	\$136,082	\$169,494	\$156,829	\$136,028	\$130,323	\$117,295	\$93,408	\$78,471	\$77,402	\$84,925	\$87,831	\$1,378,992
(8) sub-total Dth	1,695,814	3,243,979	4,690,730	4,846,283	4,152,227	2,913,296	1,647,166	874,890	622,341	573,652	639,241	755,220	26,654,839
(9) FT-2 Storage Revenue from marketers	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$370,679	\$4,448,149
(10) TOTAL Fixed Revenue	\$5,533,947	\$10,280,334	\$14,711,559	\$15,194,984	\$13,071,220	\$9,266,685	\$5,381,716	\$3,018,923	\$2,249,308	\$2,100,155	\$2,298,466	\$2,653,598	\$85,760,896
(11) <u>II. Variable Cost Revenue</u>													
(12) (a) Firm Sales dth	1,695,814	3,243,979	4,690,730	4,846,283	4,152,227	2,913,296	1,647,166	874,890	622,341	573,652	639,241	755,220	26,654,839
(13) Variable Cost Factor	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346	\$3,8346
(14) Variable Revenue	\$6,502,769	\$12,439,362	\$17,987,072	\$18,583,557	\$15,922,128	\$11,171,326	\$6,316,222	\$3,354,852	\$2,386,429	\$2,199,726	\$2,451,234	\$2,895,967	\$102,210,644
(15) TOTAL Variable Revenue	\$6,502,769	\$12,439,362	\$17,987,072	\$18,583,557	\$15,922,128	\$11,171,326	\$6,316,222	\$3,354,852	\$2,386,429	\$2,199,726	\$2,451,234	\$2,895,967	\$102,210,644
(16) Total Gas Cost Revenue	\$12,036,716	\$22,719,696	\$32,698,631	\$33,778,541	\$28,993,348	\$20,438,011	\$11,697,938	\$6,373,775	\$4,635,737	\$4,299,881	\$4,749,700	\$5,549,565	\$187,971,540

- (2) AEL-1, pg 12, Sum [Lines (2):(5), (7)]  
(3) AEL-1, pg 1, Line 1, col (e)  
(4) Line (2) x Line (3)  
(5) AEL-1, pg 12, Sum [Lines (1), (6), (8)]  
(6) AEL-1, pg 1, Line 1, col (d)  
(7) Line (5) x Line (6)  
(8) Line (2) + Line (5)  
(9) [AEL-5, pg 2, Line (26)] ÷ 12  
(10) Sum[Lines (4), (7), (9)]  
(12) Line (8)  
(13) AEL-1, pg 1, Line (2)  
(14) Line (12) x Line (13)  
(15) Line (14)  
(16) Line (10) + Line (15)

REDACTED

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

Description (a)	Nov-18 (b)	Dec-18 (c)	Jan-19 (d)	Feb-19 (e)	Mar-19 (f)	Apr-19 (g)	May-19 (h)	Jun-19 (i)	Jul-19 (j)	Aug-19 (k)	Sep-19 (l)	Oct-19 (m)	Total (n)
(1) Fixed Costs	\$4,729,063	\$10,471,730	\$10,470,396	\$10,401,565	\$10,470,396	\$4,886,910	\$4,909,854	\$4,933,176	\$4,956,120	\$4,956,120	\$4,933,176	\$4,956,120	\$81,074,626
(2) Capacity Release Revenue	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(3) Less System Pressure to DAC	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(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	\$4,729,063	\$10,471,730	\$10,470,396	\$10,401,565	\$10,470,396	\$4,886,910	\$4,909,854	\$4,933,176	\$4,956,120	\$4,956,120	\$4,933,176	\$4,956,120	\$81,074,626
(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	32.92
(8) Working Capital Requirement	\$426,523	\$944,464	\$944,344	\$938,136	\$944,344	\$440,759	\$442,828	\$444,932	\$447,001	\$447,001	\$444,932	\$447,001	\$447,001
(9) Weighted Average Cost of Capital	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%
(10) Return on Working Capital Requirement	\$30,496	\$67,529	\$67,521	\$67,077	\$67,521	\$31,514	\$31,662	\$31,813	\$31,961	\$31,961	\$31,813	\$31,961	\$31,961
(11) Cost of Debt (Long Term Debt + Short Term Debt)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%
(12) Interest Expense	\$10,322	\$22,856	\$22,853	\$22,703	\$22,853	\$10,666	\$10,716	\$10,767	\$10,817	\$10,817	\$10,767	\$10,817	\$10,817
(13) Taxable Income	\$20,175	\$44,673	\$44,667	\$44,374	\$44,667	\$20,848	\$20,946	\$21,045	\$21,143	\$21,143	\$21,045	\$21,143	\$21,143
(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	0.7900
(15) Return and Tax Requirement	\$25,537	\$56,548	\$56,541	\$56,169	\$56,541	\$26,390	\$26,514	\$26,640	\$26,763	\$26,763	\$26,640	\$26,763	\$26,763
(16) Fixed Working Capital Requirement	\$35,859	\$79,404	\$79,394	\$78,872	\$79,394	\$37,056	\$37,230	\$37,407	\$37,581	\$37,581	\$37,407	\$37,581	\$37,581
(17) Variable Costs	\$7,262,144	\$13,514,000	\$18,447,647	\$15,299,613	\$11,254,562	\$5,270,422	\$2,950,736	\$1,877,590	\$1,479,803	\$1,503,131	\$1,809,331	\$3,714,381	\$84,383,359
(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	\$7,262,144	\$13,514,000	\$18,447,647	\$15,299,613	\$11,254,562	\$5,270,422	\$2,950,736	\$1,877,590	\$1,479,803	\$1,503,131	\$1,809,331	\$3,714,381	\$84,383,359
(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	32.92
(24) Working Capital Requirement	\$654,986	\$1,218,852	\$1,663,826	\$1,379,899	\$1,015,069	\$475,349	\$266,132	\$169,343	\$133,466	\$135,570	\$163,187	\$335,007	\$335,007
(25) Weighted Average Cost of Capital	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%
(26) Return on Working Capital Requirement	\$46,831	\$87,148	\$118,964	\$98,663	\$72,577	\$33,987	\$19,028	\$12,108	\$9,543	\$9,693	\$11,668	\$23,953	\$23,953
(27) Cost of Debt (Long Term Debt + Short Term Debt)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%
(28) Interest Expense	\$15,851	\$29,496	\$40,265	\$33,394	\$24,565	\$11,503	\$6,440	\$4,098	\$3,230	\$3,281	\$3,949	\$8,107	\$8,107
(29) Taxable Income	\$30,981	\$57,652	\$78,699	\$65,269	\$48,013	\$22,484	\$12,588	\$8,010	\$6,313	\$6,412	\$7,719	\$15,846	\$15,846
(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	0.7900
(31) Return and Tax Requirement	\$39,216	\$72,977	\$99,619	\$82,619	\$60,776	\$28,461	\$15,934	\$10,139	\$7,991	\$8,117	\$9,771	\$20,058	\$20,058
(32) Variable Working Capital Requirement	\$55,067	\$102,473	\$139,884	\$116,013	\$85,340	\$39,964	\$22,375	\$14,237	\$11,221	\$11,398	\$13,720	\$28,165	\$639,856
(1) AEL-1, Pg 5, Line (63)	(14) Tax Law effective Jan. 1, 2018												
(6) Sum(Lines (1)-(5))	(25) Line (24) x Line (25)												
(7) Dkt 4770	(27) Dkt 4770												
(8) [Lines(6) x Line (7)] ÷ 365	(28) Line (24) x Line (27)												
(9) Dkt 4770	(29) Line (26) - Line (28)												
(10) Line (8) x Line (9)	(30) Tax Law effective Jan. 1, 2018												
(11) Dkt 4770	(31) Line (29) ÷ Line (30)												
(12) Line (8) x Line (11)	(32) Line (28) + Line (31)												
(13) Line (10) - Line (12)													

REDACTED

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

Description (a)	Nov-18 (b)	Dec-18 (c)	Jan-19 (d)	Feb-19 (e)	Mar-19 (f)	Apr-19 (g)	May-19 (h)	Jun-19 (i)	Jul-19 (j)	Aug-19 (k)	Sep-19 (l)	Oct-19 (m)	Total (n)
(33) Storage Fixed Costs	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92
(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	32.92
(39) Working Capital Requirement													
(40) Weighted Average Cost of Capital	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%
(41) Return on Working Capital Requirement													
(42) Cost of Debt (Long Term Debt + Short Term Debt)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%
(43) Interest Expense													
(44) Taxable Income													
(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	0.7900
(46) Return and Tax Requirement													
(47) Storage Fixed Working Capital Requirement													\$294,286

REDACTED

- (33) AEL-1, pg 5, Line (62)  
(34) AEL-1, Pg 9, Line (3)  
(37) Sum[Lines (33) : (36)]  
(38) Dkt 4770  
(39) [Line (37) x Line (38)] ÷ 365  
(40) Dkt 4770  
(41) Line (39) x Line (40)  
(42) Dkt 4770  
(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-18 (c)	Dec-18 (d)	Jan-19 (e)	Feb-19 (f)	Mar-19 (g)	Apr-19 (h)	May-19 (i)	Jun-19 (j)	Jul-19 (k)	Aug-19 (l)	Sep-19 (m)	Oct-19 (n)	Total (o)
(1) <b>Storage Inventory Balance</b>	NGC-EDA-2, pg 15	\$10,709,439	\$8,744,595	\$6,589,191	\$4,585,003	\$2,927,575	\$3,318,030	\$4,430,023	\$5,420,550	\$6,518,610	\$7,616,975	\$8,992,301	\$10,381,303	
(2) Hedging		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(3) Subtotal	(1) + (2)	\$10,709,439	\$8,744,595	\$6,589,191	\$4,585,003	\$2,927,575	\$3,318,030	\$4,430,023	\$5,420,550	\$6,518,610	\$7,616,975	\$8,992,301	\$10,381,303	
(4) Weighted Average Cost of Capital	Dkt 4770	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(5) Return on Working Capital Requirement	(3) x (4)	\$765,725	\$625,239	\$471,127	\$327,828	\$209,322	\$237,239	\$316,747	\$387,569	\$466,081	\$544,614	\$642,950	\$742,263	\$5,736,702
(6) Cost of Debt (LTD + STD)*	Dkt 4770	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(7) Interest Charges Financed	(3) x (6)	\$259,168	\$211,619	\$159,458	\$110,957	\$70,847	\$80,296	\$107,207	\$131,177	\$157,750	\$184,331	\$217,614	\$251,228	\$1,941,653
(8) Taxable Income	(5) - (7)	\$506,556	\$413,619	\$311,669	\$216,871	\$138,474	\$156,943	\$209,540	\$256,392	\$308,330	\$360,283	\$425,336	\$491,036	
(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)	\$641,211	\$523,569	\$394,517	\$274,520	\$175,284	\$198,662	\$265,241	\$324,547	\$390,291	\$456,054	\$538,400	\$621,564	\$4,803,860
(11) Working Capital Requirement	(7) + (10)	\$900,379	\$735,188	\$553,976	\$385,477	\$246,131	\$278,958	\$372,447	\$455,724	\$548,042	\$640,385	\$756,014	\$872,792	\$6,745,513
(12) Storage-Related Inventory Costs	(11) ÷ 12	\$75,032	\$61,266	\$46,165	\$32,123	\$20,511	\$23,247	\$31,037	\$37,977	\$45,670	\$53,365	\$63,001	\$72,733	\$562,126
(13) <b>LNG Inventory Balance</b>	NGC-EDA-2, pg 17													
(14) Weighted Average Cost of Capital	Dkt 4770													
(15) Return on Working Capital Requirement	(13) x (14)	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	\$1,929,124
(16) Cost of Debt (LTD + STD)*	Dkt 4770													
(17) Interest Charges Financed	(13) x (16)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	\$652,934
(18) Taxable Income	(15) - (17)													
(19) 1 - Combined Tax Rate														
(20) Return and Tax Requirement	(18) ÷ (19)	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	\$1,615,430
(21) Working Capital Requirement	(17) + (20)													\$2,268,364
(22) LNG-Related Inventory Costs	(21) ÷ 12													\$189,030
(23) Total Inventory Financing Costs	(12) + (22)													\$751,156

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

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

Rate Class (a)	Nov-18 (b)	Dec-18 (c)	Jan-19 (d)	Feb-19 (e)	Mar-19 (f)	Apr-19 (g)	May-19 (h)	Jun-19 (i)	Jul-19 (j)	Aug-19 (k)	Sep-19 (l)	Oct-19 (m)	Nov-Oct (n)
<b>SALES</b>													
(1) Residential Non-Heating	22,227	35,614	47,291	40,666	38,648	37,807	26,709	21,502	16,823	16,284	17,571	16,077	337,218
(2) Residential Heating	1,271,942	2,396,453	3,427,224	3,653,832	3,123,499	2,122,108	1,225,830	619,954	435,361	397,039	439,559	532,719	19,645,520
(3) Small C&I	125,069	293,293	453,403	454,861	389,113	258,015	116,773	65,276	40,925	36,380	48,446	52,987	2,334,542
(4) Medium C&I	200,308	392,753	606,014	526,512	452,808	383,665	197,339	125,789	98,066	94,334	97,543	110,966	3,286,097
(5) Large LLF	44,361	92,278	119,512	130,436	117,009	85,027	49,006	18,991	11,143	9,807	13,893	16,841	708,304
(6) Large HLF	19,715	23,207	31,558	27,637	23,504	22,820	19,033	15,521	13,976	13,402	16,077	16,190	242,642
(7) Extra Large LLF	2,541	5,897	5,728	7,685	6,516	3,854	3,652	1,426	342	84	293	847	38,865
(8) Extra Large HLF	9,650	4,484	-	4,654	1,128	-	8,824	6,431	5,706	6,321	5,860	8,592	61,651
(9) <b>Total Sales</b>	1,695,814	3,243,979	4,690,730	4,846,283	4,152,227	2,913,296	1,647,166	874,890	622,341	573,652	639,241	755,220	26,654,839
<b>TRANSPORTATION</b>													
(10) FT- Small	12,566	20,010	25,711	27,397	23,943	17,207	11,753	5,273	2,876	2,532	2,898	6,015	158,180
(11) FT- Medium	173,197	315,865	411,364	369,590	342,996	260,713	155,362	95,839	75,553	73,024	76,357	92,379	2,442,238
(12) FT- Large LLF	176,854	296,272	358,609	352,261	309,727	189,270	115,275	50,934	34,456	32,191	43,742	83,995	2,043,586
(13) FT- Large HLF	72,228	99,002	112,191	98,705	100,840	78,821	67,676	59,185	50,762	58,565	58,743	59,808	916,525
(14) FT- Extra Large LLF	122,430	178,864	194,162	182,450	157,144	96,228	62,805	27,050	21,711	20,914	29,069	80,905	1,173,733
(15) FT- Extra Large HLF	561,571	629,875	608,190	524,520	597,555	475,819	466,687	479,539	493,717	517,144	445,471	497,844	6,297,932
(16) <b>Total FT Transportation</b>	1,118,847	1,539,888	1,710,227	1,554,923	1,532,205	1,118,057	879,557	717,819	679,075	704,370	656,281	820,946	13,032,193
<b>Total THROUGHPUT</b>													
(17) Residential Non-Heating	22,227	35,614	47,291	40,666	38,648	37,807	26,709	21,502	16,823	16,284	17,571	16,077	337,218
(18) Residential Heating	1,271,942	2,396,453	3,427,224	3,653,832	3,123,499	2,122,108	1,225,830	619,954	435,361	397,039	439,559	532,719	19,645,520
(19) Small C&I	137,635	313,303	479,114	482,258	413,056	275,222	128,526	70,548	43,801	38,912	51,344	59,002	2,492,721
(20) Medium C&I	373,505	708,618	1,017,378	896,102	795,805	644,377	352,701	221,628	173,618	167,358	173,900	203,345	5,728,335
(21) Large LLF	221,214	388,549	478,120	482,697	426,737	274,298	164,280	69,925	45,599	41,998	57,635	100,837	2,751,890
(22) Large HLF	91,944	122,209	143,749	126,342	124,344	101,641	86,709	74,706	64,738	71,967	74,820	75,997	1,159,166
(23) Extra Large LLF	124,972	184,761	199,890	190,135	163,660	100,082	66,456	28,476	22,053	20,999	29,362	81,753	1,212,598
(24) Extra Large HLF	571,222	634,359	608,190	529,174	598,683	475,819	475,511	485,970	499,423	523,465	451,331	506,436	6,359,583
(25) <b>Total Throughput</b>	2,814,661	4,783,867	6,400,956	6,401,206	5,684,431	4,031,353	2,526,723	1,592,708	1,301,416	1,278,022	1,295,522	1,576,166	39,687,032

Source: Attachment TEP-1

REDACTED

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

<u>Rate Class</u> (a)	<u>Reference</u>	<u>Line #</u>	<u>Nov-18</u> (b)	<u>Dec-18</u> (c)	<u>Jan-19</u> (d)	<u>Feb-19</u> (e)	<u>Mar-19</u> (f)	<u>Total</u> (g)	<u>%</u> (h)
<u>SALES (dth)</u>									
(1) Residential Non-Heating	AEL-1, pg 16	Line (70)	23,262	38,204	51,284	43,895	41,445	198,089	0.96%
(2) Residential Heating	AEL-1, pg 16	Line (71)	1,427,542	2,671,366	3,823,410	4,071,709	3,472,841	15,466,868	74.57%
(3) Small C&I	AEL-1, pg 16	Line (72)	140,329	328,347	507,709	508,151	434,061	1,918,598	9.25%
(4) Medium C&I	AEL-1, pg 16	Line (74)	219,507	433,972	673,174	582,575	498,842	2,408,070	11.61%
(5) Large LLF	AEL-1, pg 16	Line (76)	50,351	103,529	133,751	145,764	130,655	564,050	2.72%
(6) Large HLF	AEL-1, pg 16	Line (78)	20,722	24,404	33,793	29,481	24,653	133,052	0.64%
(7) Extra Large LLF	AEL-1, pg 16	Line (80)	2,960	6,686	6,453	8,641	7,329	32,069	0.15%
(8) Extra Large HLF	AEL-1, pg 16	Line (82)	10,344	4,484	0	4,654	1,128	20,610	0.10%
(9) Total Sales	Sum[(1):(8)]		1,895,016	3,610,993	5,229,573	5,394,870	4,610,955	20,741,406	100.00%
(10) Low Load Factor	Sum[(2):(5),(7)]		1,840,689	3,543,901	5,144,497	5,316,840	4,543,729	20,389,655	98.30%
(11) High Load Factor	Sum[(1),(6),(8)]		54,327	67,092	85,076	78,030	67,226	351,751	1.70%

**2018/2019 Design Day Send Out**

(12) Pipeline	175,722	Dktherm
(13) Underground Storage	42,671	Dktherm
(14) LNG	171,834	Dktherm
(15) Total Projected 2018/2019 Design Day	390,227	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)**

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1) Residential Non-Heating	22,227	35,614	47,291	40,666	38,648	37,807	26,709	21,502	16,823	16,284	17,571	16,077	337,218
(2) Residential Heating	1,271,942	2,396,453	3,427,224	3,653,832	3,123,499	2,122,108	1,225,830	619,954	435,361	397,039	439,559	532,719	19,645,520
(3) Small C&I	125,069	293,293	453,403	454,861	389,113	258,015	116,773	65,276	40,925	36,380	48,446	52,987	2,334,542
(4) Small Transport	12,566	20,010	25,711	27,397	23,943	17,207	11,753	5,273	2,876	2,532	2,898	6,015	158,180
(5) Medium C&I	200,308	392,753	606,014	526,512	452,808	383,665	197,339	125,789	98,066	94,334	97,543	110,966	3,286,097
(6) Med Transport	173,197	315,865	411,364	369,590	342,996	260,713	155,362	95,839	75,553	73,024	76,357	92,379	2,442,238
(7) Large Low Load	44,361	92,278	119,512	130,436	117,009	85,027	49,006	18,991	11,143	9,807	13,893	16,841	708,304
(8) Large High Load- Transport	176,854	296,272	358,609	352,261	309,727	189,270	115,275	50,934	34,456	32,191	43,742	83,995	2,043,586
(9) Large High Load	19,715	23,207	31,558	27,637	23,504	22,820	19,033	15,521	13,976	13,402	16,077	16,190	242,642
(10) Large High Load- Transport	72,228	99,002	112,191	98,705	100,840	78,821	67,676	59,185	50,762	58,565	58,743	59,808	916,525
(11) XL Low Load	122,430	178,864	194,162	182,450	157,144	96,228	62,805	27,050	21,711	20,914	29,069	80,905	1,173,733
(12) XL Low Load- Transport	9,650	4,484	0	4,654	1,128	0	8,824	6,431	5,706	6,321	5,860	8,592	61,651
(13) XL High Load	561,571	629,875	608,190	524,520	597,555	475,819	466,687	479,539	493,717	517,144	445,471	497,844	6,297,932
(14) XL High Load- Transport	2,814,661	4,783,867	6,400,956	6,401,206	5,684,431	4,031,353	2,526,723	1,592,708	1,301,416	1,278,022	1,295,522	1,576,166	39,687,032
(15) <b>Total</b>													
(16) HLF	685,392	792,183	799,231	696,182	761,675	615,266	588,928	582,177	580,984	611,716	543,721	598,511	7,855,967
(17) LLF	2,129,269	3,991,684	5,601,726	5,705,024	4,922,756	3,416,087	1,937,794	1,010,531	720,432	666,306	751,801	977,655	31,831,064

**BaseLoad**

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(18) Residential Non-Heating	16,525	17,076	17,076	15,424	17,076	16,525	17,076	16,525	16,823	16,284	16,525	16,077	199,012
(19) Residential Heating	414,769	428,595	428,595	387,118	428,595	414,769	428,595	414,769	428,595	397,039	414,769	428,595	5,014,803
(20) Small C&I	41,006	42,373	42,373	38,272	42,373	41,006	42,373	41,006	40,925	36,380	41,006	42,373	491,463
(21) Small Transport	2,709	2,799	2,799	2,528	2,799	2,709	2,799	2,709	2,799	2,532	2,709	2,799	32,687
(22) Medium C&I	94,546	97,698	97,698	88,243	97,698	94,546	97,698	94,546	97,698	94,334	94,546	97,698	1,146,950
(23) Med Transport	73,348	75,793	75,793	68,458	75,793	73,348	75,793	73,348	75,553	73,024	73,348	75,793	889,394
(24) Large Low Load	11,362	11,741	11,741	10,604	11,741	11,362	11,741	11,362	11,143	9,807	11,362	11,741	135,705
(25) Large Low Load- Transport	35,997	37,196	37,196	33,597	37,196	35,997	37,196	35,997	34,456	32,191	35,997	37,196	430,213
(26) Large High Load	14,170	14,643	14,643	13,226	14,643	14,170	14,643	14,170	13,976	13,402	14,170	14,643	170,498
(27) Large High Load- Transport	54,805	56,632	56,632	51,152	56,632	54,805	56,632	54,805	50,762	56,632	54,805	56,632	660,927
(28) XL Low Load	235	242	242	219	242	235	242	235	242	84	235	242	2,697
(29) XL Low Load- Transport	23,378	24,158	24,158	21,820	24,158	23,378	24,158	23,378	21,711	20,914	23,378	24,158	278,747
(30) XL High Load	5,833	4,484	0	4,654	1,128	0	6,027	5,833	5,706	6,027	5,833	6,027	51,552
(31) XL High Load- Transport	474,891	490,721	490,721	443,231	490,721	474,891	466,687	474,891	490,721	490,721	445,471	490,721	5,724,385
(32) <b>Total</b>	1,263,574	1,304,150	1,299,666	1,178,546	1,300,794	1,257,741	1,281,659	1,263,574	1,291,109	1,249,372	1,234,154	1,304,694	15,229,034
(33) HLF	566,224	583,556	579,071	527,686	580,199	560,392	561,065	566,224	577,987	583,066	536,804	584,100	6,806,375
(34) LLF	697,350	720,595	720,595	650,860	720,595	697,350	720,595	697,350	713,122	666,306	697,350	720,595	8,422,659

REDACTED

Derivation of Monthly Design Sales

Heat Volumes

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(35) Residential Non-Heating	5,702	18,538	30,215	25,242	21,572	21,282	9,633	4,976	0	0	1,046	0	138,206
(36) Residential Heating	857,173	1,967,859	2,998,629	3,266,714	2,694,904	1,707,339	797,236	205,185	6,766	0	24,790	104,124	14,630,717
(37) Small C&I	84,063	250,920	411,030	416,589	346,741	217,010	74,401	24,270	0	0	7,440	10,614	1,843,079
(38) Small Transport	9,858	17,211	22,912	24,869	21,144	14,498	8,954	2,564	77	0	190	3,216	125,493
(39) Medium C&I	105,762	295,055	508,316	438,269	355,110	289,118	99,641	31,243	368	0	2,996	13,268	2,139,147
(40) Med Transport	99,849	240,072	335,571	301,131	267,203	187,364	79,569	22,491	0	0	3,009	16,585	1,552,844
(41) Large Low Load- Transport	32,999	80,537	107,771	119,831	105,269	73,666	37,265	7,629	0	0	2,531	5,101	572,599
(42) Large Low Load- Transport	140,857	259,075	321,412	318,665	272,531	153,274	78,078	14,938	0	0	7,745	46,799	1,613,373
(43) Large High Load	5,545	8,565	16,915	14,412	8,862	8,650	4,391	1,351	0	0	1,906	1,547	72,144
(44) Large High Load- Transport	17,423	42,370	55,559	47,553	44,208	24,015	11,043	4,379	0	1,933	3,938	3,176	255,597
(45) XL Low Load	2,307	5,654	5,486	7,466	6,273	3,619	3,409	1,191	99	0	59	605	36,168
(46) XL Low Load-Transport	99,052	154,707	170,004	160,630	132,986	72,850	38,647	3,671	0	0	5,691	56,748	894,986
(47) XL High Load	3,818	0	0	0	0	0	2,797	598	0	294	27	2,565	10,099
(48) XL High Load-Transport	86,681	139,154	117,470	81,289	106,834	928	0	4,648	2,997	26,424	0	7,123	573,547
(49) Total	1,551,087	3,479,716	5,101,290	5,222,660	4,383,637	2,773,612	1,245,063	329,135	10,307	28,650	61,368	271,471	24,457,998

(50) HLF	119,168	208,627	220,160	168,496	181,476	54,875	27,864	15,953	2,997	28,650	6,917	14,411	1,049,593
(51) LLF	1,431,919	3,271,089	4,881,131	5,054,164	4,202,161	2,718,738	1,217,200	313,181	7,310	0	54,451	257,060	23,408,405
(52) Normal Billing DD	421	747	1024	1051	889	658	322	155	18	0	14	166	5467

Heat Factors

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(53) Residential Non-Heating	14	25	30	24	24	32	30	32	0	0	75	0	25
(54) Residential Heating	2,035	2,635	2,928	3,108	3,030	2,593	2,479	1,321	367	0	1,771	627	2,676
(55) Small C&I	200	336	401	396	390	330	231	156	0	0	531	64	337
(56) Small Transport	23	23	22	24	24	22	28	17	4	0	14	19	23
(57) Medium C&I	251	395	496	417	399	439	310	201	20	0	214	80	391
(58) Med Transport	237	321	328	287	300	285	247	145	0	0	215	100	284
(59) Large Low Load	78	108	105	114	118	112	116	49	0	0	181	31	105
(60) Large Low Load- Transport	334	347	314	303	306	233	243	96	0	0	553	282	295
(61) Large High Load	13	11	17	14	10	13	14	9	0	0	136	9	13
(62) Large High Load- Transport	41	57	54	45	50	36	34	28	0	7,730	281	19	47
(63) XL Low Load	5	8	5	7	7	5	11	8	5	0	4	4	7
(64) XL Low Load-Transport	235	207	166	153	150	111	120	24	0	0	406	342	164
(65) XL High Load	9	0	0	0	0	0	9	4	0	1,176	2	15	2
(66) XL High Load-Transport	206	186	115	77	120	1	0	30	162	105,694	0	43	105
(67) Total	3,683	4,659	4,981	4,969	4,928	4,212	3,871	2,119	559	114,600	4,383	1,634	4,474

(68) Normal Billing DD	421	747	1024	1051	889	658	322	155	18	0	14	166	5467
(69) Design Billing DD	498	851	1159	1186	1005	758	359	157	19	3	27	209	6231

REDACTED

**Derivation of Monthly Design Sales**

**Design Sales**

	<u>Nov-18</u>	<u>Dec-18</u>	<u>Jan-19</u>	<u>Feb-19</u>	<u>Mar-19</u>	<u>Apr-19</u>	<u>May-19</u>	<u>Jun-19</u>	<u>Jul-19</u>	<u>Aug-19</u>	<u>Sep-19</u>	<u>Oct-19</u>	<u>Nov-Oct</u>
	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(70) Residential Non-Heating	23,262	38,204	51,284	43,895	41,445	41,039	27,838	21,540	16,823	16,284	18,571	16,077	356,261
(71) Residential Heating	1,427,542	2,671,366	3,823,410	4,071,709	3,472,841	2,381,404	1,319,273	621,539	428,595	397,039	463,287	559,290	21,637,295
(72) Small C&I	140,329	328,347	507,709	508,151	434,061	290,973	125,494	65,463	40,925	36,380	55,567	55,696	2,589,095
(73) Small Transport	14,356	22,414	28,738	30,578	26,684	19,409	12,803	5,292	2,799	2,532	3,080	6,835	175,519
(74) Medium C&I	219,507	433,972	673,174	582,575	498,842	427,574	209,018	126,030	97,698	94,334	100,411	114,352	3,577,487
(75) Med Transport	191,323	349,403	455,700	408,110	377,634	289,168	164,688	96,012	75,553	73,024	79,238	96,611	2,656,465
(76) Large Low Load	50,351	103,529	133,751	145,764	130,655	96,215	53,374	19,050	11,143	9,807	16,315	18,143	788,098
(77) Large Low Load- Transport	202,423	332,465	401,074	393,025	345,056	212,548	124,426	51,049	34,456	32,191	51,155	95,938	2,275,807
(78) Large High Load	20,722	24,404	33,793	29,481	24,653	24,134	19,548	15,532	13,976	13,402	17,901	16,584	254,130
(79) Large High Load- Transport	75,391	104,921	119,532	104,788	106,570	82,468	68,970	59,219	50,762	56,632	62,513	60,618	952,383
(80) XL Low Load	2,960	6,686	6,453	8,641	7,329	4,404	4,051	1,435	242	84	349	1,002	43,636
(81) XL Low Load-Transport	140,411	200,477	216,624	202,998	174,383	107,292	67,334	27,078	21,711	20,914	34,516	95,387	1,309,124
(82) XL High Load	10,344	4,484	0	4,654	1,128	0	9,152	6,435	5,706	6,027	5,886	9,247	63,063
(83) XL High Load-Transport	577,306	649,315	623,710	534,918	611,404	475,960	466,687	479,575	490,721	490,721	445,471	499,662	6,345,449
(84) Total	3,096,225	5,269,988	7,074,951	7,069,287	6,252,685	4,452,587	2,672,654	1,595,251	1,291,109	1,249,372	1,354,260	1,645,443	43,023,813
(85) HLF	707,025	821,328	828,319	717,736	785,200	623,600	592,194	582,301	577,987	583,066	550,342	602,188	7,971,287
(86) LLF	2,389,200	4,448,660	6,246,633	6,351,551	5,467,485	3,828,987	2,080,460	1,012,950	713,122	666,306	803,918	1,043,254	35,052,526

Source: Attachment TEP-1



**THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESS: ANN E. LEARY  
AUGUST 31, 2018**

---

Attachment AEL-2  
Annual GCR Reconciliation Filing

**Deferred Gas Cost Balances**

		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec		Jan		Feb		Mar		Apr-Mar	
		Actual		Actual		Actual		Actual		Actual		Actual		Actual		Actual		Actual		Actual		Actual		Actual		Actual	
(1)	Description # of Days in Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
<b>I. Fixed Cost Deferred</b>																											
(2)	Beginning Under/(Over) Recovery	(\$13,164,387)																									
(3)	Supply Fixed Costs (net of cap rel)	\$4,016,513																									
(4)	LNG/System Pressure to DAC / (Craty Sl)	(\$124,066)																									
(5)	Supply Related LNG O & M	\$47,965																									
(6)	NGPMP Credits	(\$1,171,974)																									
(7)	Working Capital	\$22,434																									
(8)	Total Supply Fixed Costs	\$2,990,872																									
(9)	Supply Fixed - Revenue	\$4,108,098																									
(10)	Monthly Under/(Over) Recovery	(\$1,317,226)																									
(11)	Prelim. Ending Under/(Over) Recovery	(\$13,143,612)																									
(12)	Month's Average Balance	(\$12,485,000)																									
(13)	Interest Rate (BOA Prime minus 200 bps)	2.00%																									
(14)	Interest Applied	(\$20,523)																									
(15)	Marketer Reconciliation																										
(16)	Fixed Ending Under/(Over) Recovery	(\$13,164,136)																									
(17)																											
<b>II. Variable Cost Deferred</b>																											
(18)	Beginning Under/(Over) Recovery	\$19,524,584																									
(19)	Variable Supply Costs	\$5,609,288																									
(20)	Supply Related LNG O & M	\$47,725																									
(21)	Inventory Financing - LNG	\$17,368																									
(22)	Inventory Financing - UG	\$41,623																									
(23)	Working Capital	\$32,329																									
(24)	Total Supply Variable Costs	\$5,748,333																									
(25)	Supply Variable - Revenue	\$11,688,443																									
(26)	Monthly Under/(Over) Recovery	(\$5,940,110)																									
(27)	Prelim. Ending Under/(Over) Recovery	\$13,584,474																									
(28)	Month's Average Balance	\$16,554,529																									
(29)	Interest Rate (BOA Prime minus 200 bps)	2.00%																									
(30)	Interest Applied	\$27,213																									
(31)	Gas Procurement Incentive(penalty)																										
(32)	Variable Ending Under/(Over) Recovery	\$13,611,687																									
<b>GC R Deferred Summary</b>																											
(33)	Beginning Under/(Over) Recovery	\$7,698,197																									
(34)	Gas Costs	\$9,597,425																									
(35)	Inventory Finance	\$58,991																									
(36)	Working Capital	\$54,763																									
(37)	NGPMP Credits	(\$1,171,974)																									
(38)	Total Costs	\$8,539,205																									
(39)	Revenue	\$15,796,541																									
(40)	Monthly Under/(Over) Recovery	(\$7,257,335)																									
(41)	Prelim. Ending Under/(Over) Recovery	\$440,862																									
(42)	Month's Average Balance	\$4,069,530																									
(43)	Interest Rate (BOA Prime minus 200 bps)	2.00%																									
(44)	Interest Applied	\$6,690																									
(45)	Gas Purchase Plan Incentives/(Penalties)	\$0																									
(46)	Ending Under/(Over) Recovery W/ Interest	\$447,551																									
(47)																											
(48)																											
(49)																											
(50)																											
(51)																											
(52)																											
(53)																											
(54)																											
(55)																											
(56)																											
(57)																											
(58)																											
(59)																											
(60)																											
(61)																											
(62)																											
(63)																											
(64)																											
(65)																											
(66)																											
(67)																											
(68)																											
(69)																											
(70)																											
(71)																											
(72)																											
(73)																											
(74)																											
(75)																											
(76)																											
(77)																											
(78)																											
(79)																											
(80)																											
(81)																											
(82)																											
(83)																											
(84)																											
(85)																											
(86)																											
(87)																											
(88)																											
(89)																											
(90)																											
(91)																											
(92)																											
(93)																											
(94)																											
(95)																											
(96)																											
(97)																											
(98)																											
(99)																											

Supply Actuals for Filing

Description

Apr Actual (a)	May Actual (b)	Jun Actual (c)	Jul Actual (d)	Aug Actual (e)	Sep Actual (f)	Oct Actual (g)	Nov Actual (h)	Dec Actual (i)	Jan Actual (j)	Feb Actual (k)	Mar Actual (l)	Apr-Mar Actual (m)
----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	----------------------	--------------------------

- (1) **SUPPLY FIXED COSTS - Pipeline Delivery**
- (2) Algonquin (includes East to West, Hubline, AMA credits)
- (3) TETCO/Texas Eastern
- (4) Tennessee
- (5) Tennessee Dracut for Peaking
- (6) Iroquois
- (7) Union
- (8) Transcanada
- (9) Dominion
- (10) Transco
- (11) National Fuel
- (12) Columbia
- (13) Alberta Northeast
- (14) Algonquin AFT (Crary Street)
- (15) Cargill Ltd.
- (15) Westerly Lateral
- (16) Less Credits from Mktr Releases
- (17) **Supply Fixed - Supplier**
- (18) Distrigas FCS
- (19) Total
- (20) **STORAGE FIXED COSTS - Facilities**
- (21) Texas Eastern
- (22) Dominion
- (23) Tennessee
- (24) Columbia
- (25) Keyspan LNG Tank Lease Payment
- (26) **STORAGE FIXED COSTS - Delivery**
- (27) Algonquin
- (28) TETCO
- (29) Tennessee
- (30) Dominion
- (31) Columbia
- (32) GAZ METRO LNG, LP/BCB LNG Fees: Summer
- (33) Distrigas FLS call payment
- (34) ENGIE Gas Demand Payment Winter
- (35) Texla
- (36) Emera Energy
- (37) Repsol Peaking Supply at Dracut

(38) TOTAL FIXED COSTS

(38) Sum[Lines (2) : (37)]

REDACTED

## Supply Actuals for Filing

Description	Apr Actual (a)	May Actual (b)	Jun Actual (c)	Jul Actual (d)	Aug Actual (e)	Sep Actual (f)	Oct Actual (g)	Nov Actual (h)	Dec Actual (i)	Jan Actual (j)	Feb Actual (k)	Mar Actual (l)	Apr-Mar Actual (m)
<b>(39) VARIABLE SUPPLY COSTS (Includes Injections)</b>													
(40) Tennessee (Includes ANE and Niagara)													
(41) TETCO (Includes B&W)													
(42) M3 Delivered													
(43) Maunee													
(44) Broadrun Col													
(45) Columbia Eagle and Downingtown													
(46) TETCO M2													
(47) Dominion to TETCO FTS													
(48) Transco Zone 3													
(49) DistriGas FCS													
(50) Hubline													
(51) Total Pipeline Commodity Charges	\$4,959,655	\$3,426,776	\$2,978,401	\$1,629,154	\$1,371,218	\$1,543,426	\$1,160,896	\$6,267,229	\$19,836,786	\$38,625,240	\$12,269,909	\$10,110,510	\$104,179,201
(52) Hedging Settlements and Amortization	(\$226,730)	(\$249,285)	(\$230,885)	\$256,810	\$223,310	\$144,488	\$599,366	\$1,211,420	\$240,620	\$799,725	(\$2,968,937)	\$1,798,727	\$1,598,629
(53) Hedging Contracts - Commission & Other Fees	\$38,086	\$65,969	\$89,934	(\$110,784)	(\$111,494)	(\$77,462)	(\$171,234)	\$6,189	\$51,886	\$79,326	\$73,596	\$73,578	\$7,590
(54) Hedging Contracts - Net Carry of Collateral	\$136	\$41	\$726	\$739	\$971	\$570	\$1,017	\$1,141	\$1,517	\$492	\$425	\$609	\$8,385
(55) Refunds	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(56) Less: Costs of Injections	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(57) TOTAL VARIABLE SUPPLY COSTS	\$4,771,146	\$3,243,501	\$2,838,176	\$1,775,920	\$1,484,005	\$1,611,022	\$1,590,045	\$7,485,980	\$20,130,810	\$39,504,783	\$9,374,993	\$11,983,423	\$105,793,804
<b>(58) Underground Storage</b>													
(59) LNG Withdrawals and Trucking	\$366,734	\$104,774	\$65,745	\$11,389	\$108,211	\$36,897	\$203,561	\$769,274	\$1,530,092	\$2,318,863	\$1,467,313	\$1,098,962	\$8,081,813
(60) Storage Delivery Costs	\$61,106	\$65,507	\$58,829	\$79,320	\$88,182	\$76,356	\$78,660	\$70,178	\$1,215,597	\$1,289,263	\$182,675	\$82,699	\$3,348,373
(61) TOTAL VARIABLE STORAGE COSTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(62) TOTAL VARIABLE COSTS	\$427,840	\$170,280	\$124,573	\$90,710	\$196,393	\$113,253	\$282,221	\$839,453	\$2,745,689	\$3,608,126	\$1,649,988	\$1,181,660	\$11,430,186
(63) TOTAL SUPPLY COSTS	\$5,198,987	\$3,413,781	\$2,962,749	\$1,866,630	\$1,680,398	\$1,724,275	\$1,872,266	\$8,325,432	\$22,876,499	\$43,112,909	\$11,024,981	\$13,165,084	\$117,223,990
(64) TOTAL SUPPLY COSTS	\$9,215,500	\$7,565,797	\$6,772,730	\$5,977,724	\$5,981,450	\$5,893,015	\$6,083,252	\$12,667,886	\$27,309,286	\$49,220,057	\$17,163,981	\$19,193,851	\$173,044,529
(51) Sum[Lines (40) : (50)]													
(57) Sum[Lines (51) : (56)]													
(61) Sum[Lines (58) : (60)]													
(62) Line (57) + Line (61)													
(63) Line (38) + Line (62)													

REDACTED

## Supply Actuals for Filing

## Description

	Apr Actual (a)	May Actual (b)	Jun Actual (c)	Jul Actual (d)	Aug Actual (e)	Sep Actual (f)	Oct Actual (g)	Nov Actual (h)	Dec Actual (i)	Jan Actual (j)	Feb Actual (k)	Mar Actual (l)	Apr-Mar Actual (m)
(64) <b>Storage Costs for FT-2 Calculation</b>													
(65) Storage Fixed Costs - Facilities	\$390,841	\$390,845	\$390,844	\$391,437	\$390,573	\$390,546	\$390,548	\$393,734	\$390,309	\$390,285	\$389,900	\$355,804	\$4,655,668
(66) Storage Fixed Costs - Deliveries	\$1,346,802	\$1,346,678	\$1,346,802	\$1,346,802	\$1,346,604	\$1,346,802	\$1,346,802	\$835,058	\$868,336	\$2,529,803	\$2,529,803	\$2,529,803	\$18,720,092
(67) sub-total Storage Costs	\$1,737,642	\$1,737,523	\$1,737,646	\$1,738,239	\$1,737,177	\$1,737,348	\$1,737,350	\$1,228,792	\$1,258,645	\$2,920,088	\$2,919,703	\$2,885,607	\$23,375,760
(68) Tennessee Dacrut for Peaking.	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(69) LNG Demand to DAC	(\$124,066)	(\$124,066)	(\$124,066)	(\$124,066)	(\$124,066)	(\$124,066)	(\$124,066)	\$0	\$0	\$0	\$0	\$0	(\$868,461)
(70) Inventory Financing	\$58,991	\$69,592	\$83,783	\$99,470	\$109,660	\$115,069	\$116,927	\$12,855	\$91,342	\$59,158	\$51,596	\$46,764	\$1,015,206
(71) Supply related LNG O&M Costs	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$47,965	\$575,581
(72) Working Capital Requirement	\$22,434	\$23,215	\$21,244	\$22,979	\$24,074	\$23,311	\$23,555	\$3,042	\$3,139	\$12,786	\$12,788	\$12,591	\$205,158
(73) Total FT-2 Storage Fixed Costs	\$1,742,967	\$1,754,229	\$1,766,572	\$1,784,587	\$1,794,810	\$1,799,628	\$1,801,731	\$1,392,654	\$1,401,090	\$3,039,998	\$3,032,051	\$2,992,926	\$24,303,244
(74) System Storage MDQ (Dth)	197,169	195,265	195,725	196,282	196,008	198,257	197,918	198,328	206,312	207,316	206,172	204,901	2,399,653
(75) FT-2 Storage Cost per MDQ (Dth)	\$8,8399	\$8,9838	\$9,0258	\$9,0920	\$9,1568	\$9,0773	\$9,1034	\$7,0220	\$6,7911	\$14,6636	\$14,7064	\$14,6067	\$10,1278
(76) Pipeline Variable	\$5,198,987	\$3,413,781	\$2,962,749	\$1,866,630	\$1,680,398	\$1,724,275	\$1,872,266	\$8,325,432	\$22,876,499	\$43,112,909	\$11,024,981	\$13,165,084	\$117,223,990
(77) Less Non-firm Gas Costs	(\$78,559)	(\$94,417)	(\$58,839)	(\$13,851)	(\$23,325)	(\$27,828)	(\$16,731)	(\$69,482)	(\$174,134)	(\$239,752)	(\$363,158)	(\$57,060)	(\$1,217,135)
(78) Less Company Use	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(79) Less Manchester St Balancing	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(80) Plus Cashout	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(81) Less Mkter W/drawals/Injections	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(82) Mkter Over-takes/Undertakes	(\$105,508)	\$15,217	\$43,725	\$75,333	\$46,857	(\$1,552)	(\$183,249)	\$176,006	(\$10,908)	\$848,773	(\$171,116)	(\$368,635)	\$364,945
(83) Plus Pipeline Strchg/Credit	\$523,707	\$508,042	\$524,982	\$508,086	\$524,931	\$525,367	\$508,401	\$525,389	\$234,248	\$240,982	\$241,914	\$219,394	\$5,085,444
(84) Less Mkter FT-2 Daily weather true-up	\$70,662	\$20,006	(\$33,380)	(\$4,567)	(\$15,061)	\$0	(\$278)	(\$12,437)	(\$3,267)	(\$114,542)	\$225,738	(\$25,906)	\$106,968
(85) TOTAL FIRM COMMODITY COSTS	\$5,609,288	\$3,862,631	\$3,439,237	\$2,431,631	\$2,213,800	\$2,220,261	\$2,180,410	\$8,944,909	\$22,922,438	\$43,848,371	\$10,958,359	\$12,932,876	\$121,564,211
(67) Sum[Lines (65) : (66)]													
(73) Sum[Lines (67) : (72)]													
(75) Line (73) ÷ Line (74)													
(76) Line (62)													
(85) Sum[Lines (76) : (84)]													

REDACTED

**GCR Revenue**

Description	Apr Actual (a)	May Actual (b)	Jun Actual (c)	Jul Actual (d)	Aug Actual (e)	Sep Actual (f)	Oct Actual (g)	Nov Actual (h)	Dec Actual (i)	Jan Actual (j)	Feb Actual (k)	Mar Actual (l)	Apr-Mar Actual (m)
<b>(1) I. Fixed Cost Revenue</b>													
(2) (a) Low Load dth	3,287,888	1,422,256	953,931	611,250	548,313	562,635	575,224	1,478,464	3,055,015	5,627,880	4,518,711	3,523,240	26,164,807
(3) Fixed Cost Factor	\$1,1417	\$1,1421	\$1,1437	\$1,1438	\$1,1423	\$1,1452	\$1,1419	\$1,3460	\$1,5512	\$1,5518	\$1,5521	\$1,8382	\$1,8382
(4) Low Load Revenue	\$3,753,787	\$1,624,314	\$1,091,018	\$699,147	\$626,351	\$644,356	\$656,855	\$1,989,994	\$4,738,829	\$8,733,379	\$7,013,475	\$6,476,372	\$38,047,879
(5) (b) High Load dth	71,988	58,887	53,379	40,116	39,976	42,294	39,359	54,755	67,995	92,898	85,624	72,461	719,733
(6) Fixed Cost Factor	\$0,9078	\$0,9080	\$0,9077	\$0,9060	\$0,9076	\$0,9078	\$0,9075	\$1,0189	\$1,1333	\$1,1341	\$1,1383	\$1,3754	\$1,3754
(7) High Load Revenue	\$65,352	\$53,470	\$48,450	\$36,347	\$36,283	\$38,396	\$35,717	\$55,792	\$77,058	\$105,354	\$97,469	\$99,665	\$749,352
(8) Sub-total throughput Dth	3,359,876	1,481,143	1,007,310	651,366	588,289	604,928	614,584	1,533,220	3,123,009	5,720,779	4,604,335	3,595,701	26,884,540
(9) FT-2 Storage Revenue from marketers	\$287,545	\$196,663	\$152,617	\$152,952	\$152,738	\$154,491	\$154,227	\$154,547	\$187,123	\$314,755	\$318,628	\$249,245	\$2,475,531
(10) Manchester Street Volumes (dth)	1,200	1,132	1,250	978	1,050	977	919	930	763	501	576	495	10,771
(11) Fixed cost factor (dth)	\$1,1787	\$1,1787	\$1,1787	\$1,1787	\$1,1787	\$1,1787	\$1,1787	\$1,6027	\$1,6027	\$1,6027	\$1,6027	\$1,6027	\$1,6027
(12) Manchester Street Revenue	\$1,414	\$1,335	\$1,473	\$1,153	\$1,238	\$1,152	\$1,083	\$1,490	\$1,222	\$802	\$924	\$793	\$14,079
(13) TOTAL Fixed Revenue	\$4,108,098	\$1,875,782	\$1,293,559	\$889,599	\$816,609	\$838,395	\$847,882	\$2,201,823	\$5,004,233	\$9,154,290	\$7,430,496	\$6,826,074	\$41,286,841
<b>(14) II. Variable Cost Revenue</b>													
(15) (a) Firm Sales dth	3,359,876	1,481,143	1,007,310	651,366	588,289	604,928	614,584	1,533,220	3,123,009	5,720,779	4,604,335	3,595,701	26,884,540
(16) Variable Supply Cost Factor	\$3,4752	\$3,4760	\$3,4811	\$3,4809	\$3,4770	\$3,4854	\$3,4758	\$3,5211	\$3,5698	\$3,5713	\$3,5703	\$4,2324	\$4,2324
(17) Variable Supply Revenue	11,676,208	5,148,411	3,506,520	2,267,342	2,045,506	2,108,405	2,136,197	5,398,547	11,148,618	20,430,812	16,438,937	15,218,596	\$97,524,099
(18) (b) TSS Sales dth	19,307	7,830	68	359	355	1,036	1,409	2,513	12,138	24,197	27,895	22,935	120,041
(19) TSS Surcharge Factor	\$0,0240	\$0,0870	\$0,1210	\$0,0000	\$0,0000	\$0,0000	\$0,0000	\$0,0000	\$0,0000	\$0,0000	\$0,3170	\$0,0000	\$0,0000
(20) TSS Surcharge Revenue	\$463	\$681	\$8	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$8,843	\$0	\$9,995
(21) (c) Default Sales dth	8,043	8,305	4,092	2,507	2,189	2,196	2,326	4,332	9,934	11,836	12,359	9,199	77,319
(22) Variable Supply Cost Factor	\$0,5683	\$9,5793	(\$5,0291)	\$1,6982	\$3,9444	\$4,6296	\$4,8725	\$6,7516	\$8,2332	\$5,9460	\$27,4512	\$14,5198	\$14,5198
(23) Variable Supply Revenue	\$4,571	\$79,559	(\$20,577)	\$4,257	\$8,634	\$10,168	\$11,334	\$29,250	\$81,788	\$70,376	\$339,267	\$133,568	\$752,196
(24) (d) Peaking Gas Revenue	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(25) (e) Deferred Responsibility	\$2,895	\$20,176	\$2,962	\$270	\$4,154	\$7,650	\$9,997	\$12,967	\$10,056	\$7,953	\$12,308	\$1,190	\$92,578
(26) (f) FT-1 Storage and Peaking	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(27) (g) Manchester Street Volumes (dth)	1,200	1,132	1,250	978	1,050	977	919	930	763	501	576	495	10,771
(28) Variable Supply Cost Factor (dth)	\$3,5879	\$3,5879	\$3,5879	\$3,5879	\$3,5879	\$3,5879	\$3,5879	\$3,6884	\$3,6884	\$3,6884	\$3,6884	\$4,8503	\$4,8503
(29) Manchester Street Revenue	\$4,305	\$4,063	\$4,485	\$3,510	\$3,767	\$3,506	\$3,297	\$3,430	\$2,812	\$1,847	\$2,126	\$2,399	\$39,547
(30) TOTAL Variable Revenue	\$11,688,443	\$5,252,890	\$3,493,398	\$2,275,379	\$2,062,062	\$2,129,729	\$2,160,825	\$5,444,194	\$11,243,275	\$20,510,988	\$16,801,480	\$15,355,752	\$98,418,416
(31) Total Gas Cost Revenue (w/o FT-2)	\$15,796,541	\$7,128,672	\$4,786,957	\$3,164,979	\$2,878,671	\$2,968,124	\$3,008,707	\$7,646,017	\$16,247,508	\$29,665,279	\$24,231,976	\$22,181,827	\$139,705,257

Lines (12) and (29): Pursuant to the Division of Public Utilities and Carriers' approval in Docket No. D-15-04 of the Company's transportation contract for gas delivered to Manchester St. Station, beginning in July 2015, the Company is crediting imputed revenue to offset the gas cost associated.

- (2) Sch. 6, Sum[Lines (24) : (28), (30)]  
 (3) Line (4) ÷ Line (2)  
 (19) Company's website  
 (20) Line (18) x Line (19)  
 (5) Sch. 6, Sum[Lines (22), (23), (29), (31)]  
 (6) Line (7) ÷ Line (5)  
 (21) Sch. 6, line (61)  
 (8) Line (2) + Line (5)  
 (22) Line (23) ÷ Line (21)  
 (25) Company Data  
 (10) Monthly Meter Use  
 (11) Inherent in approved GCR  
 (27) Monthly Meter Use  
 (12) Line (10) x Line (11)  
 (28) Inherent in approved GCR  
 (13) Sum[Lines (4), (7), (9), (12)]  
 (15) Line (8)  
 (30) Sum[Lines (17), (20), (23), (24), (25), (26), (29)]  
 (31) Line (13) + Line (30)

## Working Capital

## Description

## Reference

Apr  
ActualMay  
ActualJun  
ActualJul  
ActualAug  
ActualSep  
ActualOct  
ActualNov  
ActualDec  
ActualJan  
ActualFeb  
ActualMar  
ActualApr-Mar  
Actual

## (m)

(1) Supply Fixed Costs(2) Less: LNG Demand to DAC/Crany Street<sup>1</sup>

(3) Plus: Supply Related LNG O&amp;M Costs

(4) Total Adjustments

(5) Allowable Working Capital Costs

(6) Number of Days Lag

(7) Working Capital Requirement

(8) Cost of Capital

(9) Return on Working Capital Requirement

(10) Weighted Cost of Debt

(11) Interest Expense

(12) Taxable Income

(13) 1 - Combined Tax Rate<sup>2</sup>

(14) Return and Tax Requirement

(15) Supply Fixed Working Capital Requirement

(16) Supply Variable Costs

(17) Less: Balancing Related LNG Commodity to DAC

(18) Plus: Supply Related LNG O&amp;M Costs

(19) Total Adjustments

(20) Allowable Working Capital Costs

(21) Number of Days Lag

(22) Working Capital Requirement

(23) Cost of Capital

(24) Return on Working Capital Requirement

(25) Weighted Cost of Debt

(26) Interest Expense

(27) Taxable Income

(28) 1 - Combined Tax Rate<sup>2</sup>

(29) Return and Tax Requirement

(30) Supply Variable Working Capital Requirement

	Sch.1, line (5)	\$4,152,016	\$4,301,052	\$4,168,740	\$4,210,987	\$4,342,453	\$4,432,787	\$6,107,148	\$6,139,000	\$6,028,767	\$55,820,539
	Sch.1, line (6)	(\$124,066)	(\$124,066)	(\$124,066)	(\$124,066)	(\$262,800)	(\$262,800)	(\$262,800)	(\$262,800)	(\$262,800)	(\$2,182,461)
	Dkt 4323	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	(2) + (3)	(\$124,066)	(\$124,066)	(\$124,066)	(\$124,066)	(\$262,800)	(\$262,800)	(\$262,800)	(\$262,800)	(\$262,800)	(\$2,182,461)
	(1) + (4)	\$3,892,447	\$4,176,987	\$4,044,674	\$4,086,921	\$4,079,653	\$4,169,987	\$5,844,348	\$5,876,200	\$5,765,967	\$53,638,078
	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51
	[(5) x (6)] ÷ 365	\$229,388	\$237,373	\$234,962	\$240,848	\$240,420	\$245,744	\$344,416	\$346,293	\$339,797	
	Dkt 4339	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
	(7) x (8)	\$16,654	\$17,871	\$17,305	\$17,486	\$17,454	\$17,841	\$25,005	\$25,141	\$24,669	
	Dkt 4339	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
	(7) x (10)	\$5,918	\$6,351	\$6,150	\$6,214	\$6,203	\$6,340	\$8,886	\$8,934	\$8,767	
	(9) - (11)	\$10,735	\$11,520	\$11,155	\$11,272	\$11,252	\$11,501	\$16,119	\$16,207	\$15,903	
	Dkt 4323	0.65	0.65	0.65	0.65	0.65	0.65	0.79	0.79	0.79	
	(12) ÷ (13)	\$16,516	\$17,091	\$17,723	\$17,341	\$17,310	\$17,694	\$20,403	\$20,515	\$20,130	
	(11) + (14)	\$22,434	\$23,215	\$23,074	\$23,555	\$23,513	\$24,034	\$29,289	\$29,449	\$28,897	\$295,994
	Sch.1, line (22)	\$5,609,288	\$3,862,631	\$2,220,261	\$2,180,410	\$8,944,909	\$22,922,438	\$43,848,371	\$10,958,359	\$12,932,876	\$121,564,211
	Sch.1, line (23)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Dkt 4323	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	(17) + (18)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	(16) + (19)	\$5,609,288	\$3,862,631	\$2,220,261	\$2,180,410	\$8,944,909	\$22,922,438	\$43,848,371	\$10,958,359	\$12,932,876	\$121,564,211
	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51
	[(20) x (21)] ÷ 365	\$330,564	\$227,631	\$130,463	\$128,495	\$527,137	\$1,350,854	\$2,584,051	\$645,793	\$762,154	
	Dkt 4339	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
	(22) x (23)	\$23,999	\$16,526	\$9,499	\$9,329	\$38,270	\$98,072	\$187,602	\$46,885	\$55,332	
	Dkt 4339	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
	(22) x (25)	\$8,529	\$5,873	\$3,366	\$3,315	\$13,600	\$34,852	\$66,669	\$16,661	\$19,664	
	(24) - (26)	\$15,470	\$10,653	\$6,123	\$6,014	\$24,670	\$63,220	\$120,934	\$30,223	\$35,669	
	Dkt 4323	0.65	0.65	0.65	0.65	0.65	0.65	0.79	0.79	0.79	
	(27) ÷ (28)	\$23,801	\$16,389	\$9,421	\$9,252	\$37,954	\$97,261	\$153,080	\$38,257	\$45,150	
	(26) + (29)	\$32,329	\$22,262	\$12,759	\$12,567	\$51,554	\$132,114	\$219,749	\$54,919	\$64,814	\$649,700

<sup>1</sup>For the period Apr. 2017 through Oct. 2017, Dkt 4323; and for the period Nov. 2018 through Mar. 2018, Dkt 4719.<sup>2</sup>For the period Apr. 2017 through Dec. 17, Dkt 4323; and for the period Jan. 18 through Mar. 18, 2018 Tax Reform.

**Inventory Finance**

Description	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr-Mar
	Actual (a)	Actual (b)	Actual (c)	Actual (d)	Actual (e)	Actual (f)	Actual (g)	Actual (h)	Actual (i)	Actual (j)	Actual (k)	Actual (l)	(m)
(1) <b>Storage Inventory Balance</b>													
(2) Monthly Storage Deferral/Amortization	\$5,144,493 (\$37,322)	\$6,323,169 (\$102,505)	\$7,661,446 (\$191,557)	\$8,902,881 (\$79,962)	\$9,580,623 \$31,721	\$10,104,017 \$109,407	\$10,195,692 \$281,024	\$9,637,833 \$275,404	\$8,298,259 \$224,820	\$6,520,983 \$146,134	\$5,598,019 \$73,068	\$5,040,144 \$1	
(3) Subtotal	\$5,107,172	\$6,220,665	\$7,469,889	\$8,822,919	\$9,612,345	\$10,213,425	\$10,476,716	\$9,913,237	\$8,523,079	\$6,667,117	\$5,671,087	\$5,040,146	
(4) Cost of Capital	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(5) Return on Working Capital Requirement	\$370,781	\$451,620	\$542,314	\$640,544	\$697,856	\$741,495	\$760,610	\$719,701	\$618,776	\$484,033	\$411,721	\$365,915	\$6,805,364
(6) Weighted Cost of Debt	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(7) Interest Charges Financed	\$131,765	\$160,493	\$192,723	\$227,631	\$247,998	\$263,506	\$270,299	\$255,762	\$219,895	\$172,012	\$146,314	\$130,036	\$2,418,435
(8) Taxable Income	\$239,016	\$291,127	\$349,591	\$412,913	\$449,858	\$477,988	\$490,310	\$463,939	\$398,880	\$312,021	\$265,407	\$235,879	
(9) I - Combined Tax Rate	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.79	0.79	0.79	
(10) Return and Tax Requirement	\$367,716	\$447,888	\$537,832	\$635,250	\$692,089	\$735,367	\$754,324	\$713,753	\$613,662	\$394,963	\$335,958	\$298,581	\$6,527,382
(11) Working Capital Requirement	\$499,481	\$608,381	\$730,555	\$862,881	\$940,087	\$998,873	\$1,024,623	\$969,515	\$833,557	\$566,975	\$482,272	\$428,617	\$8,945,817
(12) Monthly Average	\$41,623	\$50,698	\$60,880	\$71,907	\$78,341	\$83,239	\$85,385	\$80,793	\$69,463	\$47,248	\$40,189	\$35,718	\$745,485
(13) <b>LNG Inventory Balance</b>													
(14) Cost of Capital	\$2,131,044 7.26%	\$2,318,192 7.26%	\$2,810,245 7.26%	\$3,381,969 7.26%	\$3,842,816 7.26%	\$3,905,466 7.26%	\$3,870,171 7.26%	\$3,933,984 7.26%	\$2,684,514 7.26%	\$1,680,685 7.26%	\$1,609,519 7.26%	\$1,558,618 7.26%	
(15) Return on Working Capital Requirement	\$154,714	\$168,301	\$204,024	\$245,531	\$278,988	\$283,537	\$280,974	\$285,607	\$194,896	\$122,018	\$116,851	\$113,156	\$2,448,596
(16) Weighted Cost of Debt	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(17) Interest Charges Financed	\$54,981	\$59,809	\$72,504	\$87,255	\$99,145	\$100,761	\$99,850	\$101,497	\$69,260	\$43,362	\$41,526	\$40,212	\$870,162
(18) Taxable Income	\$99,733	\$108,491	\$131,519	\$158,276	\$179,844	\$182,776	\$181,124	\$184,110	\$125,635	\$78,656	\$75,325	\$72,943	
(19) I - Combined Tax Rate	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.79	0.79	0.79	
(20) Return and Tax Requirement	\$153,435	\$166,910	\$202,338	\$243,502	\$276,683	\$281,194	\$278,652	\$283,247	\$193,285	\$99,565	\$95,349	\$92,333	\$2,366,492
(21) Working Capital Requirement	\$208,416	\$226,719	\$274,842	\$330,757	\$375,827	\$381,955	\$378,503	\$384,744	\$262,546	\$142,926	\$136,874	\$132,546	\$3,236,654
(22) Monthly Average	\$17,368	\$18,893	\$22,903	\$27,563	\$31,319	\$31,830	\$31,542	\$32,062	\$21,879	\$11,911	\$11,406	\$11,045	\$269,721
(23) TOTAL GCR Inventory Financing Costs	\$58,991	\$69,592	\$83,783	\$99,470	\$109,660	\$115,069	\$116,927	\$112,855	\$91,342	\$59,158	\$51,596	\$46,764	\$1,015,206
(1) Company Data	(13) Company Data												
(2) Company Data	(14) Dkt 4339												
(3) Line (1) + Line (2)	(15) Line (13) x Line (14)												
(4) Dkt 4339	(16) Dkt 4339												
(5) Line (3) x Line (4)	(17) Line (13) x Line (16)												
(6) Dkt 4339	(18) Line (15) - Line (17)												
(7) Line (3) x Line (6)	(19) Dkt 4323												
(8) Line (5) - Line (7)	(20) Line (18) ÷ Line (19)												
(9) Dkt 4323	(21) Line (17) + Line (20)												
(10) Line (8) ÷ Line (9)	(22) Line (21) ÷ 12												
(11) Line (7) + Line (10)	(23) Line (12) + Line (22)												
(12) Line (11) ÷ 12													

REDACTED

**THROUGHPUT (Dth)**

## Rate Class

	Apr Actual (a)	May Actual (b)	Jun Actual (c)	Jul Actual (d)	Aug Actual (e)	Sep Actual (f)	Oct Actual (g)	Nov Actual (h)	Dec Actual (i)	Jan Actual (j)	Feb Actual (k)	Mar Actual (l)	Apr-Mar Actual (m)
<b>SALES</b>													
(1) Residential Non-Heating	44,256	29,336	24,258	19,200	17,698	18,669	16,470	25,799	36,375	54,883	49,588	42,810	379,341
(2) Residential Non-Heating Low Income	1,429	1,005	683	486	438	1,424	(624)	506	908	1,479	1,192	1,139	10,064
(3) Residential Heating	2,276,588	986,291	656,511	414,665	369,201	375,999	385,111	1,049,547	2,123,640	3,918,609	3,156,062	2,437,110	18,149,333
(4) Residential Heating Low Income	194,021	100,127	67,120	43,824	38,781	40,198	37,443	85,126	174,014	295,095	237,817	192,552	1,506,117
(5) Small C&I	313,479	104,811	66,481	43,307	39,181	39,210	111,854	333,557	277,727	585,108	440,831	334,818	2,394,020
(6) Medium C&I	395,382	189,716	140,530	97,779	93,200	95,519	101,259	195,033	383,557	650,534	533,358	424,687	3,300,553
(7) Large C&I	80,576	30,177	20,339	10,256	9,086	10,365	10,185	32,729	77,403	145,182	120,731	101,572	648,602
(8) Large HLF	20,948	19,724	17,792	12,615	15,096	16,358	14,763	19,260	22,406	29,939	26,984	24,449	240,334
(9) Extra Large HLF	10,129	4,291	2,883	1,059	749	336	607	1,662	7,001	9,784	6,318	10,337	54,886
(10) Extra Large HLF	3,762	7,836	10,647	7,815	6,744	5,843	8,751	9,191	7,841	5,969	3,560	3,292	81,250
(11) Total Sales	3,340,569	1,473,313	1,007,242	651,008	587,934	603,893	613,175	1,530,707	3,110,872	5,696,582	4,576,441	3,572,766	26,764,499
<b>TSS</b>													
(13) Small	1,660	341	93	74	33	12	17	26	327	1,270	1,577	928	6,359
(14) Medium	8,327	4,570	75	134	118	1,024	806	1,986	6,054	11,692	11,398	12,266	58,450
(15) Large HLF	7,726	1,932	(99)	150	204	0	586	501	5,293	10,605	10,619	46,487	8,745
(16) Large HLF	1,594	987	0	0	0	0	0	0	464	629	4,300	771	0
(17) Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(18) Extra Large HLF	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	19,307	7,830	68	359	355	1,036	1,409	2,513	12,138	24,197	27,895	22,935	120,041
<b>Sales &amp; TSS THROUGHPUT</b>													
(21) Residential Non-Heating	44,256	29,336	24,258	19,200	17,698	18,669	16,470	25,799	36,375	54,883	49,588	42,810	379,341
(22) Residential Non-Heating Low Income	1,429	1,005	683	486	438	1,424	(624)	506	908	1,479	1,192	1,139	10,064
(23) Residential Heating	2,276,588	986,291	656,511	414,665	369,201	375,999	385,111	1,049,547	2,123,640	3,918,609	3,156,062	2,437,110	18,149,333
(24) Residential Heating Low Income	194,021	100,127	67,120	43,824	38,781	40,198	37,443	85,126	174,014	295,095	237,817	192,552	1,506,117
(25) Small C&I	313,479	104,811	66,574	43,381	39,193	39,228	111,880	335,379	278,053	586,379	442,408	335,746	2,400,379
(26) Medium C&I	403,709	194,286	140,604	97,914	93,318	96,543	102,065	197,019	389,610	662,226	544,756	436,953	3,359,003
(27) Large C&I	88,301	32,109	20,239	10,406	9,289	10,365	10,771	32,320	82,697	155,787	131,351	110,543	695,088
(28) Large HLF	22,542	20,711	17,792	12,615	15,096	16,358	14,763	19,260	22,871	30,568	31,285	25,220	249,079
(29) Extra Large HLF	10,129	4,291	2,883	1,059	749	336	607	1,662	7,001	9,784	6,318	10,337	54,886
(30) Extra Large HLF	3,762	7,836	10,647	7,815	6,744	5,843	8,751	9,191	7,841	5,969	3,560	3,292	81,250
(31) Total Sales & TSS Throughput	3,359,876	1,481,143	1,007,310	651,366	588,289	604,928	614,584	1,533,220	3,123,009	5,720,779	4,604,335	3,595,701	26,884,540
<b>FT-1 TRANSPORTATION</b>													
(33) FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	0
(34) FT-1 Medium	87,997	45,854	33,455	23,293	21,970	23,698	23,592	30,639	60,057	94,202	106,674	70,928	622,357
(35) FT-1 Large HLF	139,253	64,270	39,180	19,071	15,474	16,660	18,918	34,759	97,785	156,615	188,114	117,763	907,861
(36) FT-1 Extra Large HLF	46,755	30,869	25,530	28,075	30,186	32,023	38,641	32,023	38,641	51,303	58,673	41,269	442,698
(37) FT-1 Extra Large HLF	186,388	98,443	62,497	28,207	20,162	21,762	25,305	48,732	127,674	194,739	224,079	151,917	1,189,905
(38) FT-1 Extra Large HLF	569,383	456,839	434,173	437,754	445,240	452,915	391,880	433,197	494,103	573,189	623,062	499,034	5,810,768
(39) Default	8,043	8,305	4,092	2,507	2,189	2,196	2,326	4,332	9,934	11,836	12,359	9,199	77,319
(40) Total FT-1 Transportation	1,037,818	704,581	601,811	538,906	530,565	548,191	492,207	583,682	828,194	1,081,884	1,212,960	890,109	9,050,908
<b>FT-2 TRANSPORTATION</b>													
(42) FT-2 Small	14,840	5,565	4,962	2,460	2,299	2,308	2,343	6,121	14,942	30,920	23,834	18,268	128,860
(43) FT-2 Medium	228,063	111,699	79,934	51,690	51,122	50,384	54,721	115,362	220,831	362,383	302,105	252,568	1,880,863
(44) FT-2 Large HLF	154,331	66,850	31,676	39,593	19,167	19,167	27,361	60,802	159,214	267,279	214,763	179,315	1,238,800
(45) FT-2 Extra Large HLF	46,493	33,574	32,303	25,720	24,257	26,620	27,286	36,322	47,803	63,254	59,154	50,624	473,409
(46) FT-2 Extra Large HLF	6,478	2,108	1,453	936	423	(782)	142	126	2,476	4,034	3,026	2,441	22,861
(47) FT-2 Extra Large HLF	50,379	37,837	40,363	36,026	34,521	41,438	36,599	47,318	52,276	60,012	46,226	43,247	526,241
(48) Total FT-2 Transportation	500,584	257,632	190,691	156,426	131,072	139,134	148,452	266,050	497,542	787,882	649,107	546,463	4,271,033
<b>Total THROUGHPUT</b>													
(51) Residential Non-Heating	44,256	29,336	24,258	19,200	17,698	18,669	16,470	25,799	36,375	54,883	49,588	42,810	379,341
(52) Residential Non-Heating Low Income	1,429	1,005	683	486	438	1,424	(624)	506	908	1,479	1,192	1,139	10,064
(53) Residential Heating	2,276,588	986,291	656,511	414,665	369,201	375,999	385,111	1,049,547	2,123,640	3,918,609	3,156,062	2,437,110	18,149,333
(54) Residential Heating Low Income	194,021	100,127	67,120	43,824	38,781	40,198	37,443	85,126	174,014	295,095	237,817	192,552	1,506,117
(55) Small C&I	329,980	110,717	71,536	45,841	39,544	41,501	41,570	118,001	292,995	617,299	466,242	354,014	2,529,239
(56) Medium C&I	719,769	253,994	166,411	172,897	166,411	170,625	180,378	343,020	709,498	1,118,811	953,535	760,448	5,862,223
(57) Large C&I	381,885	163,229	91,095	69,071	43,213	46,193	57,051	128,791	339,695	579,680	534,227	407,621	2,841,749
(58) Large HLF	113,789	85,154	78,509	66,410	64,883	73,937	72,235	87,605	109,315	145,125	149,112	117,113	1,165,186
(59) Extra Large HLF	202,996	104,842	66,833	30,203	21,064	21,316	26,054	50,519	73,151	103,557	232,422	164,695	1,267,652
(60) Extra Large HLF	623,524	485,182	481,595	481,595	486,504	500,195	437,230	489,706	554,220	639,171	672,847	545,573	6,418,259
(61) Default	8,043	8,305	4,092	2,507	2,189	2,196	2,326	4,332	9,934	11,836	12,359	9,199	77,319
(62) Total Throughput	4,898,277	2,443,356	1,799,812	1,346,698	1,249,926	1,292,254	1,255,243	2,382,952	4,448,745	7,590,544	6,466,403	5,032,272	40,206,481



**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESS: ANN E. LEARY**  
**AUGUST 31, 2018**

---

Attachment AEL-3  
Projected Gas Cost Balances

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

(1) # of Days in Month	Description	Nov - Oct											
		Nov-18 forecast	Dec-18 forecast	Jan-19 forecast	Feb-19 forecast	Mar-19 forecast	Apr-19 forecast	May-19 forecast	Jun-19 forecast	Jul-19 forecast	Aug-19 forecast	Sep-19 forecast	Oct-19 forecast
(1)	(a)	30	31	31	28	31	30	31	30	31	31	30	31
(2)	(b)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(3)	(c)	\$7,218,742	\$6,226,715	\$6,249,208	\$1,833,542	(\$3,146,696)	(\$5,943,873)	(\$10,571,109)	(\$11,297,747)	(\$9,636,046)	(\$7,177,227)	(\$4,562,800)	(\$2,163,147)
(4)	(d)	\$4,729,063	\$10,471,730	\$10,470,396	\$10,401,565	\$10,470,396	\$4,886,910	\$4,909,854	\$4,933,176	\$4,956,120	\$4,956,120	\$4,933,176	\$4,956,120
(5)	(e)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)
(6)	(f)	\$35,859	\$79,404	\$79,394	\$78,872	\$79,394	\$37,056	\$37,230	\$37,407	\$37,581	\$37,581	\$37,407	\$37,581
(7)	(g)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(8)	(h)	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152
(9)	(i)	\$4,500,740	\$10,286,953	\$10,285,609	\$10,216,256	\$10,285,609	\$4,682,903	\$4,706,401	\$4,729,519	\$4,729,519	\$4,729,519	\$4,706,401	\$4,729,519
(10)	(j)	(\$5,533,947)	(\$10,280,344)	(\$14,711,559)	(\$15,194,984)	(\$13,071,220)	(\$9,266,685)	(\$5,381,716)	(\$3,018,923)	(\$2,249,308)	(\$2,100,155)	(\$2,298,466)	(\$2,653,598)
(11)	(k)	\$6,185,535	\$6,233,334	\$1,823,258	(\$3,145,186)	(\$5,932,307)	(\$10,550,773)	(\$11,269,922)	(\$9,610,269)	(\$7,155,835)	(\$4,547,863)	(\$2,154,865)	(\$87,226)
(12)	(l)	\$6,702,139	\$6,230,025	\$4,036,233	(\$655,822)	(\$4,539,501)	(\$8,247,323)	(\$10,920,516)	(\$10,454,008)	(\$8,395,940)	(\$5,862,545)	(\$3,358,833)	(\$1,125,187)
(13)	(m)	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
(14)	(n)	\$16,526	\$15,874	\$10,284	(\$1,509)	(\$11,566)	(\$20,336)	(\$27,825)	(\$25,777)	(\$21,392)	(\$14,937)	(\$8,282)	(\$2,867)
(15)	(o)	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654	\$24,654
(16)	(p)	\$6,226,715	\$6,249,208	\$1,833,542	(\$3,146,696)	(\$5,943,873)	(\$10,571,109)	(\$11,297,747)	(\$9,636,046)	(\$7,177,227)	(\$4,562,800)	(\$2,163,147)	(\$90,093)
(17)	(q)	\$16,134,580	\$17,116,637	\$18,450,728	\$19,179,422	\$16,113,730	\$11,616,132	\$5,833,442	\$2,570,378	\$1,192,974	\$388,698	(\$199,942)	(\$718,581)
(18)	(r)	\$7,262,144	\$13,514,000	\$18,447,647	\$15,299,613	\$11,254,562	\$5,270,422	\$2,950,736	\$1,877,590	\$1,479,803	\$1,503,131	\$1,809,331	\$3,714,381
(19)	(s)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(20)	(t)	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187
(21)	(u)	\$26,452	\$25,273	\$9,006	\$4,365	\$3,648	\$8,329	\$13,130	\$17,823	\$18,259	\$17,765	\$22,488	\$22,492
(22)	(v)	\$55,067	\$102,473	\$139,884	\$116,013	\$85,340	\$39,964	\$22,375	\$14,237	\$11,221	\$11,398	\$13,720	\$28,165
(23)	(w)	\$7,443,882	\$13,728,199	\$18,667,888	\$15,477,300	\$11,389,248	\$5,367,149	\$3,042,465	\$1,972,814	\$1,580,140	\$1,610,846	\$1,933,726	\$3,862,958
(24)	(x)	(\$6,502,769)	(\$12,439,362)	(\$17,987,072)	(\$18,583,557)	(\$15,922,128)	(\$11,171,326)	(\$6,316,222)	(\$3,346,852)	(\$2,386,429)	(\$2,199,726)	(\$2,451,234)	(\$2,895,967)
(25)	(y)	\$17,075,692	\$18,405,473	\$19,131,543	\$16,073,165	\$11,580,850	\$5,811,955	\$2,559,685	\$1,888,340	\$3,866,685	(\$200,182)	(\$717,450)	\$248,410
(26)	(z)	\$16,605,136	\$17,761,055	\$18,791,135	\$17,626,294	\$13,847,290	\$8,714,044	\$4,196,564	\$1,879,359	\$789,830	\$94,258	(\$458,696)	(\$235,086)
(27)	(aa)	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
(28)	(ab)	\$40,944	\$45,254	\$47,879	\$40,565	\$35,282	\$21,487	\$10,693	\$4,634	\$2,012	\$240	(\$1,131)	(\$599)
(29)	(ac)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(30)	(ad)	\$17,116,637	\$18,450,728	\$19,179,422	\$16,113,730	\$11,616,132	\$5,833,442	\$2,570,378	\$1,192,974	\$388,698	(\$199,942)	(\$718,581)	\$247,811
(31)	(ae)	\$23,353,322	\$23,343,352	\$24,699,936	\$21,012,964	\$12,967,034	\$5,672,259	(\$4,737,667)	(\$8,727,369)	(\$8,443,072)	(\$6,788,529)	(\$4,762,742)	(\$2,881,728)
(32)	(af)	\$12,110,200	\$24,080,069	\$29,012,382	\$25,795,516	\$21,819,297	\$10,251,672	\$7,954,929	\$6,905,105	\$6,530,262	\$6,553,589	\$6,836,845	\$8,764,839
(33)	(ag)	\$101,484	\$86,539	\$55,171	\$36,488	\$24,159	\$31,576	\$44,168	\$55,800	\$63,929	\$71,131	\$85,489	\$95,225
(34)	(ah)	\$90,926	\$181,877	\$219,278	\$194,885	\$164,735	\$77,020	\$59,605	\$51,644	\$48,802	\$48,979	\$51,127	\$65,746
(35)	(ai)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)	(\$333,333)
(36)	(aj)	\$11,969,276	\$24,015,152	\$28,953,497	\$25,693,556	\$21,674,857	\$10,026,935	\$7,725,368	\$6,679,216	\$6,309,660	\$6,340,365	\$6,640,128	\$8,592,477
(37)	(ak)	(\$12,036,716)	\$22,719,696	\$23,698,631	(\$33,778,541)	(\$28,993,348)	\$10,438,011	(\$11,697,938)	(\$6,373,775)	(\$4,635,737)	(\$4,299,881)	(\$4,749,700)	(\$5,549,565)
(38)	(al)	\$23,285,882	\$24,638,808	\$20,954,801	\$12,927,979	\$5,648,543	(\$4,738,818)	(\$8,710,237)	(\$8,421,929)	(\$6,769,149)	(\$2,872,315)	(\$2,872,315)	\$161,184
(39)	(am)	\$23,319,602	\$23,991,080	\$22,827,368	\$16,970,472	\$9,307,789	\$466,720	(\$6,723,932)	(\$8,574,649)	(\$7,606,111)	(\$5,768,287)	(\$3,817,528)	(\$1,360,272)
(40)	(an)	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
(41)	(ao)	\$57,470	\$61,128	\$58,163	\$39,055	\$23,716	\$1,151	(\$17,132)	(\$21,143)	(\$19,380)	(\$14,697)	(\$9,413)	(\$3,466)
(42)	(ap)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(43)	(aq)	\$23,343,352	\$24,699,936	\$21,012,964	\$12,967,034	\$5,672,259	(\$4,737,667)	(\$8,727,369)	(\$8,443,072)	(\$6,788,529)	(\$4,762,742)	(\$2,881,728)	\$157,718
(44)	(ar)	(12) [Lines (3) + Line (11)] ÷ 2	(14) [Line (12) x Line (13)] ÷ 365 x Line (1)	(22) AEL-1, pg 11, Line (22)	(30) [Line (28) x Line (29)] ÷ 365 x Line (1)	(32) Sum[Lines (27), (30), (31)]	(35) Sum[Lines (4), (7), (8), (15), (19), (21)]	(36) Line (22) + Line (23)	(37) Line (6) + Line (24)	(38) Line (5)	(39) Sum[Lines (35), (38)]	(40) Line (10) + Line (26)	(41) Sum[Lines (34), (39), (40)]
(45)	(as)	(15) AEL-2, Pg 2, Line (50)	(16) Sum[Lines (11), (14), (15)]	(24) AEL-1, pg 9, Line (32)	(25) Sum[Lines (19), (24)]	(26) AEL-1, pg 8, Line (15)	(27) Sum[Lines (18), (25), (26)]	(28) [Line (18) + Line (27)] ÷ 2	(33) Sum[Lines (41), (44), (45)]	(34) Sum[Lines (41), (44), (45)]	(35) Sum[Lines (41), (44), (45)]	(36) Sum[Lines (41), (44), (45)]	(37) Sum[Lines (41), (44), (45)]
(46)	(at)	(18) Nov-18: AEL-1, pg 7, Col (m), Line (35)	(19) AEL-1, pg 6, Line (97)	(20) AEL-1, pg 3, Line (7) ÷ 12	(21) AEL-1, pg 3, Line (7) ÷ 12	(22) AEL-1, pg 3, Line (7) ÷ 12	(23) AEL-1, pg 3, Line (7) ÷ 12	(24) AEL-1, pg 3, Line (7) ÷ 12	(25) AEL-1, pg 3, Line (7) ÷ 12	(26) AEL-1, pg 3, Line (7) ÷ 12	(27) AEL-1, pg 3, Line (7) ÷ 12	(28) AEL-1, pg 3, Line (7) ÷ 12	(29) AEL-1, pg 3, Line (7) ÷ 12
(47)	(au)	(11) Sum[Lines (3), (9), (10)]	(12) Sum[Lines (3), (9), (10)]	(13) Sum[Lines (3), (9), (10)]	(14) Sum[Lines (3), (9), (10)]	(15) Sum[Lines (3), (9), (10)]	(16) Sum[Lines (3), (9), (10)]	(17) Sum[Lines (3), (9), (10)]	(18) Sum[Lines (3), (9), (10)]	(19) Sum[Lines (3), (9), (10)]	(20) Sum[Lines (3), (9), (10)]	(21) Sum[Lines (3), (9), (10)]	(22) Sum[Lines (3), (9), (10)]



**THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESS: ANN E. LEARY  
AUGUST 31, 2018**

---

Attachment AEL-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:**

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to:				
						Base Rates	GCR	DAC	EE	LIHEAP
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
Average Customer	548	\$921.77	\$981.27	(\$59.51)	-6.1%	\$0.00	(\$26.04)	(\$31.68)	\$0.00	\$0.00
	608	\$1,002.66	\$1,068.70	(\$66.04)	-6.2%	\$0.00	(\$28.89)	(\$35.17)	\$0.00	\$0.00
	667	\$1,082.20	\$1,154.61	(\$72.41)	-6.3%	\$0.00	(\$31.68)	(\$38.56)	\$0.00	\$0.00
	726	\$1,161.72	\$1,240.54	(\$78.82)	-6.4%	\$0.00	(\$34.49)	(\$41.97)	\$0.00	\$0.00
	785	\$1,241.20	\$1,326.42	(\$85.22)	-6.4%	\$0.00	(\$37.28)	(\$45.38)	\$0.00	\$0.00
	845	\$1,322.08	\$1,413.81	(\$91.73)	-6.5%	\$0.00	(\$40.14)	(\$48.84)	\$0.00	\$0.00
	905	\$1,402.98	\$1,501.18	(\$98.20)	-6.5%	\$0.00	(\$42.95)	(\$52.30)	\$0.00	\$0.00
	964	\$1,482.44	\$1,587.11	(\$104.67)	-6.6%	\$0.00	(\$45.80)	(\$55.73)	\$0.00	\$0.00
	1,023	\$1,561.96	\$1,673.03	(\$111.07)	-6.6%	\$0.00	(\$48.60)	(\$59.14)	\$0.00	\$0.00
	1,082	\$1,641.50	\$1,758.94	(\$117.44)	-6.7%	\$0.00	(\$51.39)	(\$62.53)	\$0.00	\$0.00
	1,142	\$1,722.42	\$1,846.34	(\$123.93)	-6.7%	\$0.00	(\$54.23)	(\$65.98)	\$0.00	\$0.00

**Residential Heating Low Income:**

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to:				
						Base Rates	Total Bill Discount	GCR	DAC	EE
(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)
Average Customer	548	\$685.39	\$730.84	(\$45.45)	-6.2%	\$0.00	\$14.70	(\$26.04)	(\$32.74)	\$0.00
	608	\$745.42	\$795.82	(\$50.40)	-6.3%	\$0.00	\$16.30	(\$28.89)	(\$36.29)	\$0.00
	667	\$804.43	\$859.71	(\$55.28)	-6.4%	\$0.00	\$17.87	(\$31.68)	(\$39.81)	\$0.00
	726	\$863.43	\$923.61	(\$60.18)	-6.5%	\$0.00	\$19.46	(\$34.49)	(\$43.34)	\$0.00
	785	\$922.40	\$987.47	(\$65.06)	-6.6%	\$0.00	\$21.04	(\$37.28)	(\$46.87)	\$0.00
	845	\$982.41	\$1,052.44	(\$70.03)	-6.7%	\$0.00	\$22.64	(\$40.14)	(\$50.43)	\$0.00
	905	\$1,042.45	\$1,117.42	(\$74.98)	-6.7%	\$0.00	\$24.24	(\$42.95)	(\$54.02)	\$0.00
	964	\$1,101.40	\$1,181.30	(\$79.90)	-6.8%	\$0.00	\$25.84	(\$45.80)	(\$57.54)	\$0.00
	1,023	\$1,160.41	\$1,245.19	(\$84.78)	-6.8%	\$0.00	\$27.41	(\$48.60)	(\$61.05)	\$0.00
	1,082	\$1,219.41	\$1,309.08	(\$89.68)	-6.9%	\$0.00	\$29.00	(\$51.39)	(\$64.59)	\$0.00
	1,142	\$1,279.42	\$1,374.08	(\$94.66)	-6.9%	\$0.00	\$30.61	(\$54.23)	(\$68.20)	\$0.00

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

**Residential Non-Heating:**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	Difference due to:															
																		Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates					Base DAC		ISR	EE	LIHEAP	GET
																							GCR	DAC	ISR	EE	LIHEAP	GET					

**Residential Non-Heating Low Income:**

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference due to:																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																									
				Difference	% Chg	Base Rates	Total Bill Discount	GCR	Base DAC	DAC	ISR	EE	LIHEAP	GET																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																															
(18)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																													

### C & I Small:

**C & I Medium:**

Annual Consumption (Therms)			Current Rates		Difference due to:							
	Proposed Rates		Difference	% Chg	Base Rates	GCR	Base DAC	DAC	ISR	EE	LIHEAP	GET
(18)												
(19)												
(20)												
(21)												
(22)	6,907	\$8,828.05	\$9,569.99	-7.8%	\$0.00	(\$328.08)	(\$391.60)	\$0.00	\$0.00	\$0.00	\$0.00	(\$22.26)
(23)	7,650	\$9,663.68	\$10,485.46	-7.8%	\$0.00	(\$363.36)	(\$433.77)	\$0.00	\$0.00	\$0.00	\$0.00	(\$24.65)
(24)	8,391	\$10,496.56	\$11,397.94	-7.9%	\$0.00	(\$398.60)	(\$475.74)	\$0.00	\$0.00	\$0.00	\$0.00	(\$27.04)
(25)	9,136	\$11,334.22	\$12,315.67	-8.0%	\$0.00	(\$433.98)	(\$518.02)	\$0.00	\$0.00	\$0.00	\$0.00	(\$29.44)
(26)	9,880	\$12,170.86	\$13,232.18	-8.0%	\$0.00	(\$469.30)	(\$560.18)	\$0.00	\$0.00	\$0.00	\$0.00	(\$31.84)
(27)	<b>Average Customer</b>	<b>10,623</b>	<b>\$13,006.46</b>	<b>-8.1%</b>	\$0.00	(\$504.61)	(\$602.32)	\$0.00	\$0.00	\$0.00	\$0.00	(\$34.23)
(28)	11,366	\$13,842.05	\$15,063.01	-8.1%	\$0.00	(\$539.88)	(\$644.45)	\$0.00	\$0.00	\$0.00	\$0.00	(\$36.63)
(29)	12,111	\$14,679.73	\$15,980.73	-8.1%	\$0.00	(\$575.29)	(\$686.68)	\$0.00	\$0.00	\$0.00	\$0.00	(\$39.03)
(30)	12,855	\$15,516.36	\$16,897.30	-8.2%	\$0.00	(\$610.63)	(\$728.88)	\$0.00	\$0.00	\$0.00	\$0.00	(\$41.43)
(31)	13,596	\$16,349.25	\$17,809.78	-8.2%	\$0.00	(\$645.80)	(\$770.92)	\$0.00	\$0.00	\$0.00	\$0.00	(\$43.82)
(32)	14,340	\$17,185.90	\$18,726.32	-8.2%	\$0.00	(\$681.14)	(\$813.07)	\$0.00	\$0.00	\$0.00	\$0.00	(\$46.21)

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

**C & I LLF Large:**

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to:					GET
						Base Rates	GCR	Base DAC	DAC	ISR	
(1)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
(2)											
(3)											
(4)											
(5)											
(6)											
(7)	37,587	\$45,725.97	\$48,934.46	(\$3,208.49)	-6.6%	\$0.00	(\$1,785.40)	(\$1,326.84)	\$0.00	\$0.00	(\$96.25)
(8)	41,634	\$50,381.50	\$53,935.44	(\$3,553.94)	-6.6%	\$0.00	(\$1,977.63)	(\$1,469.69)	\$0.00	\$0.00	(\$106.62)
(9)	45,683	\$55,039.73	\$58,939.25	(\$3,899.53)	-6.6%	\$0.00	(\$2,169.94)	(\$1,612.60)	\$0.00	\$0.00	(\$116.99)
(10)	49,731	\$59,696.93	\$63,942.02	(\$4,245.08)	-6.6%	\$0.00	(\$2,362.22)	(\$1,755.51)	\$0.00	\$0.00	(\$127.35)
(11)	53,777	\$64,351.37	\$68,941.83	(\$4,590.46)	-6.7%	\$0.00	(\$2,554.42)	(\$1,898.33)	\$0.00	\$0.00	(\$137.71)
(12)	<b>57,825</b>	<b>\$69,008.58</b>	<b>\$73,944.56</b>	<b>(\$4,935.98)</b>	<b>-6.7%</b>	\$0.00	(\$2,746.67)	(\$2,041.23)	\$0.00	\$0.00	(\$148.08)
(13)	61,873	\$73,665.78	\$78,947.29	(\$5,281.52)	-6.7%	\$0.00	(\$2,938.96)	(\$2,184.11)	\$0.00	\$0.00	(\$158.45)
(14)	65,920	\$78,321.26	\$83,948.25	(\$5,626.99)	-6.7%	\$0.00	(\$3,131.19)	(\$2,326.99)	\$0.00	\$0.00	(\$168.81)
(15)	69,967	\$82,977.39	\$88,949.85	(\$5,972.46)	-6.7%	\$0.00	(\$3,323.44)	(\$2,469.85)	\$0.00	\$0.00	(\$179.17)
(16)	74,016	\$87,635.63	\$93,953.70	(\$6,318.07)	-6.7%	\$0.00	(\$3,515.78)	(\$2,612.75)	\$0.00	\$0.00	(\$189.54)
(17)	78,063	\$92,291.13	\$98,954.66	(\$6,663.53)	-6.7%	\$0.00	(\$3,708.00)	(\$2,755.62)	\$0.00	\$0.00	(\$199.91)

**C & I HLF Large:**

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to:					GET
						Base Rates	GCR	Base DAC	DAC	ISR	
(18)											
(19)											
(20)											
(21)											
(22)	41,956	\$42,170.75	\$47,728.84	(\$5,558.09)	-11.6%	\$0.00	(\$4,153.64)	(\$1,237.71)	\$0.00	\$0.00	(\$166.74)
(23)	46,471	\$46,441.73	\$52,597.93	(\$6,156.21)	-11.7%	\$0.00	(\$4,600.64)	(\$1,370.88)	\$0.00	\$0.00	(\$184.69)
(24)	50,991	\$50,716.90	\$57,471.92	(\$6,755.01)	-11.8%	\$0.00	(\$5,048.12)	(\$1,504.24)	\$0.00	\$0.00	(\$202.65)
(25)	55,507	\$54,988.69	\$62,341.96	(\$7,353.27)	-11.8%	\$0.00	(\$5,495.21)	(\$1,637.46)	\$0.00	\$0.00	(\$220.60)
(26)	60,028	\$59,264.78	\$67,216.94	(\$7,952.16)	-11.8%	\$0.00	(\$5,942.78)	(\$1,770.82)	\$0.00	\$0.00	(\$238.56)
(27)	<b>64,545</b>	<b>\$63,537.40</b>	<b>\$72,087.96</b>	<b>(\$8,550.56)</b>	<b>-11.9%</b>	\$0.00	(\$6,389.96)	(\$1,904.08)	\$0.00	\$0.00	(\$256.52)
(28)	69,062	\$67,810.05	\$76,958.99	(\$9,148.94)	-11.9%	\$0.00	(\$6,837.14)	(\$2,037.33)	\$0.00	\$0.00	(\$274.47)
(29)	73,583	\$72,086.12	\$81,833.98	(\$9,747.86)	-11.9%	\$0.00	(\$7,284.73)	(\$2,170.69)	\$0.00	\$0.00	(\$292.44)
(30)	78,099	\$76,357.93	\$86,704.04	(\$10,346.10)	-11.9%	\$0.00	(\$7,731.81)	(\$2,303.91)	\$0.00	\$0.00	(\$310.38)
(31)	82,619	\$80,633.13	\$91,578.04	(\$10,944.91)	-12.0%	\$0.00	(\$8,179.30)	(\$2,437.26)	\$0.00	\$0.00	(\$328.35)
(32)	87,137	\$84,907.55	\$96,450.96	(\$11,543.41)	-12.0%	\$0.00	(\$8,626.57)	(\$2,570.54)	\$0.00	\$0.00	(\$346.30)

### C & I LLF Extra-Large:

### **C & I HLF Extra-Large:**

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference due to:									
				Base Rates	GCR	Base DAC	DAC	ISR	EE	LIHEAP	GET		
												% Chg	Difference
(18)													
(19)													
(20)													
(21)													
(22)	486,528	\$400,976.20	\$456,550.75	\$0.00	(\$48,166.28)	(\$5,741.03)	\$0.00	\$0.00	\$0.00	\$0.00	(\$1,667.24)		
(23)	538,924	\$443,491.89	\$505,051.44	\$0.00	(\$53,353.47)	(\$6,359.29)	\$0.00	\$0.00	\$0.00	\$0.00	(\$1,846.79)		
(24)	591,320	\$486,006.73	\$553,551.31	\$0.00	(\$58,540.67)	(\$6,977.57)	\$0.00	\$0.00	\$0.00	\$0.00	(\$2,026.34)		
(25)	643,718	\$528,523.86	\$602,053.71	\$0.00	(\$63,728.08)	(\$7,595.87)	\$0.00	\$0.00	\$0.00	\$0.00	(\$2,205.90)		
(26)	696,109	\$571,035.04	\$650,549.35	\$0.00	(\$68,914.79)	(\$8,214.09)	\$0.00	\$0.00	\$0.00	\$0.00	(\$2,385.43)		
(27)	<b>748,506</b>	<b>\$613,551.43</b>	<b>\$699,050.88</b>	\$0.00	(\$74,102.09)	(\$8,832.37)	\$0.00	\$0.00	\$0.00	\$0.00	(\$2,564.98)		
(28)	800,903	\$656,067.82	\$747,552.42	\$0.00	(\$79,289.41)	(\$9,450.65)	\$0.00	\$0.00	\$0.00	\$0.00	(\$2,744.54)		
(29)	853,294	\$698,578.98	\$796,048.06	\$0.00	(\$84,476.11)	(\$10,068.90)	\$0.00	\$0.00	\$0.00	\$0.00	(\$2,924.07)		
(30)	905,692	\$741,096.10	\$844,550.42	\$0.00	(\$89,663.51)	(\$10,687.18)	\$0.00	\$0.00	\$0.00	\$0.00	(\$3,103.63)		
(31)	958,088	\$783,610.95	\$893,050.30	\$0.00	(\$94,850.73)	(\$11,305.44)	\$0.00	\$0.00	\$0.00	\$0.00	(\$3,283.18)		
(32)	1,010,485	\$826,127.37	\$941,551.82	\$0.00	(\$100,038.00)	(\$11,923.72)	\$0.00	\$0.00	\$0.00	\$0.00	(\$3,462.73)		



**THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESS: ANN E. LEARY  
AUGUST 31, 2018**

---

Attachment AEL-5  
FT-2 Demand Rate

REDACTED

The Narragansett Electric company  
d/b/a National Grid  
Docket No. 4872  
Attachment AEL-5  
Redacted  
Page 1 of 3

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

<u>Item</u> (a)	<u>Reference</u> (b)	<u>Proposed</u> (c)	<u>Billing Units</u> (d)
(1) FT-2 Demand Usage (Dt) Nov 2018 - Oct 2019 Weighted Average Upstream Pipeline Transportation	Pg 2, Line (22)	\$17.0642	Dth/Mth
(2) Cost	NGC-EDA-4	\$0.7693	Per Dth of capacity
(3) Storage and Peaking charge for FT-1 firm transportation Customers eligible for TSS	Pg 3, Line (5)	\$1.6478	Per Dth

REDACTED

The Narragansett Electric company  
d/b/a National Grid  
Docket No. 4872  
Attachment AEL-5  
Redacted  
Page 2 of 3

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

<u>Description</u> (a)	<u>Source</u>		<u>Amount</u> (d)
	<u>Reference</u> (b)	<u>Line #</u> (c)	
(1) Storage Fixed Costs	AEL-1 pg 5	Line (62)	
Less:			
(2) System Pressure to DAC			\$0
(3) Credits			\$0
(4) Refunds			\$0
(5) Total Credits	Sum [(2):(4)]		\$0
Plus:			
(6) Supply Related LNG O&M Costs	AEL-1 Pg 2	Line (8) + Line (9)	\$829,823
(7) Working Capital Requirement	AEL-1 pg 10	Line (47)	\$294,286
(8) Tennessee Dracut for peaking / FT Demand Everett	AEL-1 pg 4	Line (5)	\$2,400,173
(9) Total Additions	Sum [(6):(8)]		\$3,524,282
(10) Total Storage Fixed Costs	(1) + (5) + (9)		
Inventory Financing			
(11) Underground	AEL-1 pg 11	Line (12)	\$562,126
(12) LNG	AEL-1 pg 11	Line (22)	\$189,030
(13) Total Storage Fixed Costs	(10) + (11) + (12)		
(14) LNG Storage MDQ (Dth)	AEL-1 pg 13	Line (14)	
(15) AGT	NGC-EDA-4		
(16) TENN	NGC-EDA-4		
(17) Total Storage MDQ	Sum [(14):(16)]		
(18) Storage MDQ X 12 Months	(17) x 12		MDCQ Dth
(19) FT- 2 Demand Rate	(13) ÷ (18)		\$16.7383 per MDCQ Dth
(20) Uncollectible %	Docket 4770		1.91%
(21) Total FT-2 Demand Rate adjusted for Uncollectibles	(19) ÷ [(1 - (20))]		\$17.0642 per MDCQ Dth
(22) MDQ-U	Mkter MDQ Forecast		4,199
(23) MDQ-P	Mkter MDQ Forecast		<u>17,947</u>
(24) Marketer MDQs	(22) + (23)		22,146 Dth/Mth
(25) FT-2 Storage Costs	(19) x (24) x 12 Months		<b>\$4,448,149</b>

REDACTED

The Narragansett Electric company  
d/b/a National Grid  
Docket No. 4872  
Attachment AEL-5  
Redacted  
Page 3 of 3

**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**

<u>Description</u> (a)	<u>Source</u>		<u>Amount</u> (d)
	<u>Reference</u> (b)	<u>Line #</u> (c)	
(1) Total Storage Fixed Costs	Pg 2	Line (13)	
(2) Usage (Dth) Nov 2018 - Oct 2019	AEL-1, pg 2	Line (17)	
(3) Volumetric Rate	(1) ÷ (2)		\$1.6164
(4) Uncollectible %	Docket 4770		1.91%
(5) Volumetric Rate Including Uncollectible	(3) ÷ [1 - (4)]		\$1.6478 per dth
(6) Storage and Peaking charge applied to FT-1 firm transportation Customers eligible for TSS			\$0.1647 per therm



**THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESS: ANN E. LEARY  
AUGUST 31, 2018**

---

Attachment AEL-6  
FT-2 Capacity Allocator Percentages

**RI Gas Company  
Capacity Assignment Table**

		<u>% of Peak Day Requirement</u>				<u>% of Total Capacity</u>			
Load	Rate Class	Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
(1)	HLF	Res - Non-Heating	63.0%	7.0%	30.0%	100.0%	0.9%	0.7%	0.7%
(2)	HLF	Res - Non-Heating LI	63.0%	7.0%	30.0%	100.0%			
(3)	LLF	Res - Heating	42.0%	11.0%	47.0%	100.0%	60.1%	63.2%	63.2%
(4)	LLF	Res - Heating LI	42.0%	11.0%	47.0%	100.0%			
(5)	LLF	Small	42.0%	11.0%	47.0%	100.0%	7.8%	8.5%	8.5%
(6)	LLF	Med	42.0%	11.0%	47.0%	100.0%	9.7%	9.6%	9.6%
(7)	LLF	Large Low Load	42.0%	11.0%	47.0%	100.0%	2.3%	2.6%	2.6%
(8)	HLF	Large High Load	63.0%	7.0%	30.0%	100.0%	0.6%	0.4%	0.4%
(9)	LLF	XL Low Load	42.0%	11.0%	47.0%	100.0%	0.1%	0.1%	0.1%
(10)	HLF	XL High Load	63.0%	7.0%	30.0%	100.0%	0.1%	0.0%	0.0%

(11)	HLF	High Load Factor	63.0%	7.0%	30.0%	100.0%
(12)	LLF	Low Load Factor	42.0%	11.0%	47.0%	100.0%
(13)		Total	43.0%	11.0%	47.0%	100.0%

7.8%	3.5%	3.5%
92.2%	96.5%	96.5%
100.0%	100.0%	100.0%



**THE NARRAGANSETT ELECTRIC COMPANY**  
**d/b/a NATIONAL GRID**  
**RIPUC DOCKET NO. 4872**  
**2018 GAS COST RECOVERY FILING**  
**WITNESS: ANN E. LEARY**  
**AUGUST 31, 2018**

---

Attachment AEL-7  
Marketer Reconciliation

**2016-17 & 2017-18 Annual Marketer Reconciliation**

Description (a)	# of days (b)	WLA/Algonquin		to NEGSC (e)	STX/Algonquin		Lambertville, NJ (Maumee/Dowington)		Dracut (i)	Total (j) = Sum[(c) : (i)]
		ELA/Algonquin (c)	(d)		(f)	(g)	(h)			
2017-2018 Marketer Reconciliation										
Month of activity										
(1)	Nov-17	30	195,000	255,000	285,000	121,320	69,090	72,210	7,200	1,004,820
(2)	Dec-17	31	201,500	263,469	294,500	125,333	72,447	76,570	7,192	1,041,011
(3)	Jan-18	31	201,500	263,500	294,500	125,364	71,703	73,315	7,099	1,036,981
(4)	Feb-18	28	182,000	238,000	266,000	113,232	63,952	63,532	6,412	933,128
(5)	Mar-18	31	201,469	263,500	294,500	125,364	71,207	70,959	7,006	1,034,005
(6)	Apr-18	30	196,778	257,327	287,617	122,394	70,165	69,269	7,040	1,010,590
(7)	May-18	31	212,939	262,415	282,100	126,418	72,695	72,106	6,913	1,035,586
(8)	Jun-18	30	195,000	255,000	285,000	121,320	69,960	71,610	6,630	1,004,520
(9)	Jul-18	31	195,000	255,000	285,000	121,320	69,960	71,610	6,630	1,004,520
(10)	Aug-18	31	195,000	255,000	285,000	121,320	69,960	71,610	6,630	1,004,520
(11)	Sep-18	30	195,000	255,000	285,000	121,320	69,960	71,610	6,630	1,004,520
(12)	Oct-18	31	195,000	255,000	285,000	121,320	69,960	71,610	6,630	1,004,520
(13)	Total		2,366,186	3,078,211	3,429,217	1,466,025	841,059	856,011	82,012	12,118,721
Approved										
(14)	System Average*		\$0.6168	\$0.6168	\$0.6168	\$0.6168	\$0.6168	\$0.6168	\$0.6168	
(15)	Path *		\$0.7630	\$0.8717	\$1.0067	\$1.1166	\$0.3507	\$0.3698	\$1.7441	
(16)	Credit/Surcharge		(\$0.1462)	(\$0.2549)	(\$0.3899)	(\$0.4998)	\$0.2661	\$0.2470	(\$1.1273)	
Revised										
(17)	System Average		\$0.6140	\$0.6140	\$0.6140	\$0.6140	\$0.6140	\$0.6140	\$0.6140	
(18)	Path		\$0.7616	\$0.8704	\$1.0067	\$1.1152	\$0.3507	\$0.3619	\$1.7441	
(19)	Credit/Surcharge		(\$0.1476)	(\$0.2564)	(\$0.3927)	(\$0.5012)	\$0.2633	\$0.2521	(\$1.1301)	
(20)	Variance- approved Surcharge/Credit vs. Revised Surcharge/Credit		(\$0.0014)	(\$0.0015)	(\$0.0028)	(\$0.0014)	(\$0.0028)	\$0.0051	(\$0.0028)	
(21)	Annual MDCQ		2,366,186	3,078,211	3,429,217	1,466,025	841,059	856,011	82,012	12,118,721
(22)	Updated 2017-18 Marketer Reconciliation Adjustment		(\$3,313)	(\$4,617)	(\$9,602)	(\$2,052)	(\$2,355)	\$4,366	(\$230)	(\$17,803)

(13): Sum[Lines (1) : (12)]  
(14) & (15): Dkt 4719 NGC-4 filed on October 23, 2017  
(16): Line (14) - Line (15)  
(19): Line (17) - Line (18)  
(20): Line (19) - Line (16)  
(21): Line (13)  
(22): Line (20) x Line (21)

\* GCR rates approved with the Revised GCR filing per Docket No. 4719 filed on October 23, 2017

**2016-17 & 2017-18 Annual Marketer Reconciliation**

Description (a)	# of days (b)	ELA/Algonquin	WLA/Algonquin	to NEGSC	STX/Algonquin	Lambertville, NJ	Maumee/Dowington)	Dracut	Total
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j) = Sum[(c) : (i)]
<b>2016-2017 Marketer Reconciliation</b>									
<b>Month of activity</b>									
(23)	Nov-16	195,000	255,000	285,000	121,320	81,420	15,900	120	953,760
(24)	Dec-16	201,500	263,500	294,500	125,333	84,134	35,154	248	1,004,369
(25)	Jan-17	201,500	263,500	294,500	125,364	84,134	29,605	217	998,820
(26)	Feb-17	182,000	237,972	265,972	113,232	75,992	32,116	224	907,508
(27)	Mar-17	201,500	263,500	294,500	125,364	84,103	31,031	248	1,000,246
(28)	Apr-17	195,000	255,000	285,000	121,320	81,420	59,040	240	997,020
(29)	May-17	201,469	263,500	294,469	125,364	84,134	61,938	248	1,031,122
(30)	Jun-17	190,890	249,660	279,030	118,800	79,710	66,150	240	984,480
(31)	Jul-17	201,500	263,469	294,438	125,333	84,103	61,721	248	1,030,812
(32)	Aug-17	201,500	263,500	294,500	125,333	84,134	70,742	248	1,039,957
(33)	Sep-17	195,000	255,000	285,000	121,320	81,420	67,470	240	1,005,450
(34)	Oct-17	201,500	263,500	294,500	125,364	84,134	70,680	248	1,039,926
(35)	Total	2,368,359	3,097,101	3,461,409	1,473,447	988,838	601,547	2,769	11,993,470
<b>Approved</b>									
(36)	System Average	\$0.3766	\$0.3766	\$0.3766	\$0.3766	\$0.3766	\$0.3766	\$0.3766	
(37)	Path	\$0.8476	\$0.9687	\$1.0093	\$1.1810	\$0.1524	\$0.4162	\$1.3261	
(38)	Credit/Surcharge	(\$0.4710)	(\$0.5921)	(\$0.6327)	(\$0.8044)	\$0.2242	(\$0.0396)	(\$0.9495)	
<b>Revised</b>									
(39)	System Average	\$0.3748	\$0.3748	\$0.3748	\$0.3748	\$0.3748	\$0.3748	\$0.3748	
(40)	Path	\$0.8476	\$0.9687	\$1.0093	\$1.1810	\$0.1524	\$0.4162	\$1.3261	
(41)	Credit/Surcharge	(\$0.4728)	(\$0.5939)	(\$0.6345)	(\$0.8062)	\$0.2224	(\$0.0414)	(\$0.9513)	
(42)	Variance- approved Surcharge/Credit vs. Revised Surcharge								
(43)	Annual MDCQ	(\$0.0018)	(\$0.0018)	(\$0.0018)	(\$0.0018)	(\$0.0018)	(\$0.0018)	(\$0.0018)	
(44)	Updated 2016-17 Marketer Reconciliation Adjustment	2,368,359	3,097,101	3,461,409	1,473,447	988,838	601,547	2,769	11,993,470
(45)	Under/(Over)-collections 2016-17 Marketer Reconciliation <sup>1</sup>	(\$4,263)	(\$5,575)	(\$6,231)	(\$2,652)	(\$1,780)	(\$1,083)	(\$5)	(\$21,588)
(46)	Total 2016-17 amount subject to Marketer Reconciliation								
(47)	Already Collected from Marketers <sup>2</sup>								
(48)	Under/(Over)-collections for 2017-18 Marketer Reconciliation								
(49)	Total 2016-17 & 2017-18 Marketer Reconciliation Credited to Marketers								
(50)	Total 2016-17 & 2017-18 Marketer Reconciliation_Surcharge to Firm Sales Customers								
									<b>\$24,654</b>

<sup>1</sup> Docket No. 4719 Attachment AEL-7, Line 48, filed on October 23, 2017 updated to reflect actual collections for Aug. 2017 - Oct. 2017.  
<sup>2</sup> It is the sum of Nov. 2017 - July 2018 as reflected in GCR Monthly Deferred Report filed on August 17, 2018, and Aug. 2018 - Oct. 2018 projected collections.

**Testimony of  
Theodore E. Poe, Jr.**

**THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC DOCKET NO. 4872  
2018 GAS COST RECOVERY FILING  
WITNESS: THEODORE E. POE, JR.  
AUGUST 31, 2018**

---

**DIRECT TESTIMONY**

**OF**

**THEODORE E. POE, JR.**

**Table of Contents**

I.	Introduction.....	1
II.	Summary of Retail and Wholesale Natural Gas Forecasts .....	4
III.	The 2018 Gas Forecast .....	5

1   **I.     Introduction**

2   **Q.     Please state your name and business address.**

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

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

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

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

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

1 Jensen Associates, Inc. of Boston, where I was responsible for developing a variety of  
2 computer-forecasting models to analyze natural gas supply and demand for interstate  
3 pipeline and local gas distribution companies. I joined Boston Gas Company in 1989,  
4 where I was responsible for modeling and forecasting customers' natural gas resource  
5 requirements and managing the resource planning process. In 1998-99, I assumed the  
6 same responsibilities for Essex Gas Company and Colonial Gas Company. In 2000, I  
7 assumed responsibility for modeling and forecasting the natural gas resource  
8 requirements of The Brooklyn Union Gas Company and KeySpan Gas East Corporation.  
9 In 2008, I assumed responsibility for modeling and forecasting the natural gas resource  
10 requirements of the Company, as well as Niagara Mohawk Power Corporation.  
11

12 **Q. Are you a member of any professional organizations?**

13 A. Yes. I am a member of the Northeast Gas Association, the New England-Canada  
14 Business Council, and the American Meteorological Society.  
15

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

18 A. Yes. I testified before the PUC in previous Gas Cost Recovery filings in Docket Nos.  
19 4719 and 4647. I also submitted pre-filed written testimony in support of the Company's  
20 2017 rate case filing in Docket No. 4770. In addition, I have testified in a number of

1 proceedings before the Massachusetts Department of Public Utilities and the New  
2 Hampshire Public Utilities Commission.

3  
4 **Q. What is the purpose of your testimony in this proceeding?**

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

8  
9 **Q. Are you sponsoring any attachments?**

10 A. Yes. I am sponsoring the following attachments that accompany my testimony:

11 Attachment TEP-1 National Grid RI Retail Volume Forecast  
12 2018 vs. 2017 Forecast

13  
14 Attachment TEP-2 National Grid RI Retail Meter Count Forecast  
15 2018 vs. 2017 Forecast

16  
17 Attachment TEP-3 National Grid RI Economic Forecast  
18 2018 vs. 2017 Forecast

19  
20 Attachment TEP-4 National Grid RI Retail Volume Forecast by Rate Class  
21 2018 vs. 2017 Forecast

22  
23 Attachment TEP-5 National Grid RI Retail Meter Count Forecast by Rate Class  
24 2018 vs. 2017 Forecast  
25

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

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

6    **II.   Summary of Retail and Wholesale Natural Gas Forecasts**

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

8    A.    Annually, beginning in April, the Company uses the following 5-step process to prepare  
9       its 10-year forecast of customer requirements:

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

16       For the Company's forecast, "retail" refers to gas delivered and metered at customers'  
17       burner tips, and "wholesale" refers to gas received and metered flowing into the  
18       Company's distribution system. The Company's retail forecast is prepared through  
19       econometric and statistical modeling of both customer count (meter count) and use-per-  
20       customer. This process is documented in greater detail in the Company's biannual Gas  
21       Long-Range Resource and Requirements Plan, filed most recently in Docket No. 4816

1 for the forecast period 2017/18 through 2026/27. Billing data is modeled at the rate class  
2 level and further sub-categorized as sales or transportation (either capacity-eligible or  
3 capacity-exempt). The Company's volume forecast is the product of meter count and  
4 use-per-customer at the rate class level. The retail forecast takes into account the impact  
5 of the Company's energy efficiency programs.

6  
7 The Company's wholesale forecast is based on its retail forecast. The retail forecast is  
8 adjusted to correct for the billing lag inherent therein, and it is further adjusted to account  
9 for unaccounted-for gas. Unaccounted-for gas is the measure of the difference between  
10 gas supplies that are received and metered flowing into the Company's distribution  
11 system and gas delivered and metered at customers' burner tips. These two forecasts  
12 (retail and wholesale) serve as the annual basis of the Company's supply, engineering,  
13 and financial planning.

14  
15 **III. The 2018 Gas Forecast**

16 **Q. What is the role of the 2018 gas forecast in the Gas Cost Recovery proceeding?**

17 A. With 73 percent of the Company's sales occurring between the months of November  
18 through March, as set forth in the pre-filed joint direct testimony of Company witnesses  
19 Nancy G. Culliford and Elizabeth D. Arangio on Attachment NGC/EDA-2, Page 1, the  
20 Company's gas resource portfolio and gas supply purchase planning are designed to  
21 address its customers' needs during the winter peak period and throughout the year. Each

1        year, the Company constructs its gas forecast by accounting for the most recent heating  
2        season's actual customer usage patterns. This provides the Company a growing set of  
3        historical data with which to build its econometric forecast using its most recent  
4        economic outlook.

5  
6        The Company's forecast of sales and throughput requirements under normal weather  
7        conditions and under design winter conditions serves three purposes. First, the forecasts  
8        provide key inputs for the computation of National Grid's projected Gas Cost Recovery  
9        costs. Second, the Company's forecasts of design winter requirements form the basis for  
10       the Company's allocation of fixed costs between High Load Factor and Low Load Factor  
11       service classifications. Third, forecasts of total annual sales and throughput requirements  
12       provide the denominators used in the Company's computation of applicable charges on a  
13       dollars per therm basis. The Company's forecasts of future gas service requirements also  
14       serve as important indicators of the need for additional capacity to ensure the reliability  
15       of its service, particularly during periods of extreme weather, as reflected in measures of  
16       design winter, cold snap, and design day requirements. The Company's long-range  
17       forecasts of service requirements also play an important role in its assessment of the  
18       economics of alternative gas supply resources.

1 **Q. How do the forecasted sales requirements for 2018/19 compare to the prior retail**  
2 **forecast for 2017/18?**

3 A. A comparison of the Company's 2017/18 gas forecast of firm retail volumes for the  
4 period November 2017 through October 2018 and its current firm retail volume forecast  
5 for November 2018 through October 2019 is shown in Table 1, below.  
6

7 **Table 1**

	2017/18 Forecasted Volume (MMBtu)	2018/19 Forecasted Volume (MMBtu)
Residential Sales	19,443,660	19,982,738
<u>C&amp;I Sales</u>	<u>6,451,808</u>	<u>6,672,101</u>
Total Sales	25,895,468	26,654,839
<u>C&amp;I Transportation</u>	<u>13,534,432</u>	<u>13,032,192</u>
Total	39,429,900	39,687,032

8 Source: Attachment TEP-1  
9

10 In summary, the 2018/19 forecast for Total Sales and Transportation customers shows a  
11 0.6 percent increase over the 2017/18 forecast, with Total Sales increasing by 2.9 percent  
12 and Commercial and Industrial (C&I) Transportation decreasing by 3.7 percent.  
13

14 Attachment TEP-1 contains tables showing planning year<sup>1</sup> (PY) volumes from PY 2011  
15 through PY 2026 for the Company's current (2018) volume forecast and last year's  
16 (2017) forecast. The data is presented for Residential Non-Heating, Residential Heating,

---

<sup>1</sup> The forecast planning year is November 1 through October 31.

1 C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all  
2 other volumes. Charts are provided in Attachment TEP-1 for visual comparison. The  
3 primary change in the volume forecast from 2017 to 2018 is a decrease in the forecasted  
4 FT-2 Transportation customer growth. The five-year per annum growth rate in volumes  
5 (excluding Other) from PY 2019 to PY 2024 is 0.3 percent, which is slightly lower than  
6 the 0.8 percent per annum growth rate forecasted last year.

7  
8 Attachment TEP-2 contains tables from PY 2011 through PY 2026 showing the  
9 Company's current (2018) meter count forecast and year's (2017) forecast. The data is  
10 presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1  
11 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts  
12 are provided in Attachment TEP-2 for visual comparison. The primary changes in the  
13 meter count forecast from 2017 to 2018 are a decrease in the forecasted growth rate of  
14 FT-2 Transportation customers and a slowing of the reduction in Residential Non-  
15 Heating customers. The five-year per annum growth rate in meter count (excluding  
16 Other) from PY 2019 to PY 2024 is 0.7 percent, which is the same as the 0.7 percent per  
17 annum growth rate forecasted last year.

18  
19 On a wholesale basis (see Attachment NGC/EDA-2, Page 1), the Company forecasts  
20 sales volumes to be 29,432,358 MMBtu<sup>2</sup> for the period November 2018 through October

---

<sup>2</sup> One million British thermal units (MMBtu).

1        2019. Comparatively, in the Company's previous wholesale forecast for November 2017  
2        through October 2018, as filed in Docket No. 4719, the sales volume was projected to be  
3        26,638,727 MMBtu. Wholesale sales volume is projected to increase 10.5 percent.

4  
5        Attachment TEP-3 contains tables for calendar year economic data from 1990 through  
6        2026 for the Company's current (2018) forecast and last year's (2017) forecast. The data  
7        is presented for the following key indicators: Natural Gas Residential Price, Residential  
8        No. 2 Oil Price, the Gas-to-Oil Price Ratio, Rhode Island Gross Domestic Product,  
9        Households, and Non-Farm Employment. Charts are provided in Attachment TEP-3 for  
10       visual comparison. The overall 2018 economic forecast shows little change from the  
11       2017 economic forecast, with Households and Non-Farm Employment both growing at  
12       0.5 percent per annum from PY 2019 through PY 2024.

13  
14    **Q.    How has the Company accounted for the effects of weather variations in the historic**  
15    **data inputs to its 2018 gas forecast?**

16    **A.**    In preparing the 2018 gas forecast, the Company used its monthly customer billing data  
17        (volume and number of customers) for the period August 2010 through February 2018 to  
18        forecast the number of customers and use-per-customer for each of the rate groups the  
19        Company analyzes. The Company obtained the historical monthly use-per-customer  
20        values by dividing volume of total billed therms for each month by the number of  
21        customers for the month. Weather, particularly heating degree days, plays the dominant

1 role in modeling the use-per-customer behavior of the Company's customers under the  
2 wide range of weather observed in the historical period. The Company's forecast then  
3 applies its normalized heating degree days as the basis of its forecast of use-per-customer  
4 under normal weather conditions.

5  
6 **Q. How did the Company's 2017/18 forecast compare to the actual billings weather**  
7 **normalized for the same period?**

8 A. According to the Company's most recent analysis, where it normalized its actual billing  
9 data for August 2017 through July 2018, actual normalized Firm Sales customers plus  
10 C&I Transportation customers totaled 41,363,340 MMBtu. The Company's normalized  
11 forecast for November 2017 through October 2018 was 39,429,900 MMBtu, as set forth  
12 in Table 1, above. Actual normalized sales were 5.4 percent higher than forecast.

13  
14 **Q. How has the Company addressed the effects of colder than normal weather on the**  
15 **development of its design winter and design day requirements?**

16 A. The Company develops appropriate design day and design year planning standards to  
17 design a least-cost, reliable supply portfolio for its forecast period. The purpose of a  
18 design day standard is to establish the amount of system-wide throughput (interstate  
19 pipeline and underground storage capacity plus local supplemental capacity) that is  
20 required to maintain the integrity of the distribution system. The Company maintains a  
21 design year standard for planning purposes to identify the amount of seasonal supplies of

1 natural gas that will be required to provide continuous service under all reasonable  
2 weather conditions. The Company establishes its design standards using a three-step  
3 process. First, the Company performs statistical analyses of the coldest days and of the  
4 annual degree days recorded over a historical period. Second, the Company conducts  
5 cost-benefit analyses to evaluate the cost of maintaining the resources necessary to meet  
6 design-level demand versus the cost to customers of experiencing service curtailments.  
7 Third, the Company identifies design standards that would maintain reliability at the  
8 lowest cost.

9  
10 **Q. Does this conclude your testimony?**

11 **A. Yes.**



Attachments of Theodore Poe, Jr.

Attachment TEP-1	National Grid RI Retail Volume Forecast 2018 vs. 2017 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2018 vs. 2017 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2018 vs. 2017 Forecast
Attachment TEP-4	National Grid RI Retail Volume Forecast by Rate Class 2018 vs. 2017 Forecast
Attachment TEP-5	National Grid RI Retail Meter Count Forecast by Rate Class 2018 vs. 2017 Forecast



## Attachment TEP-1

### National Grid RI Retail Volume Forecast

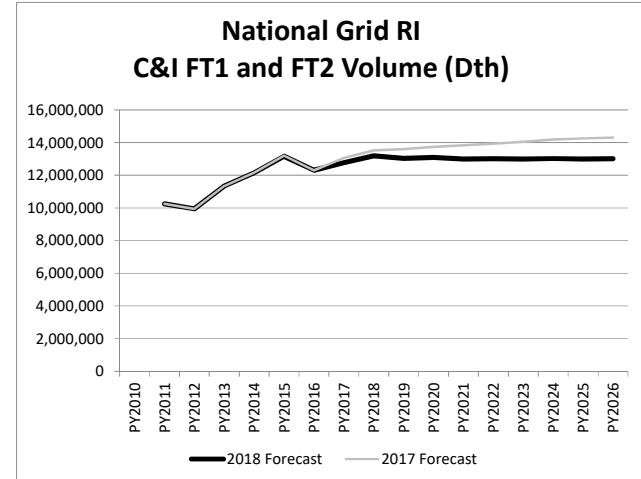
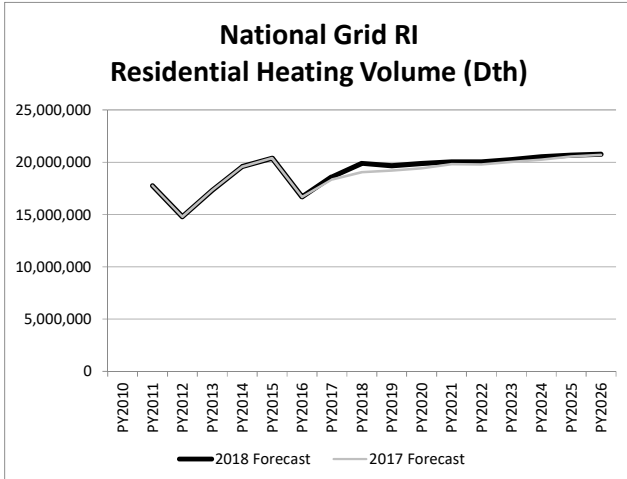
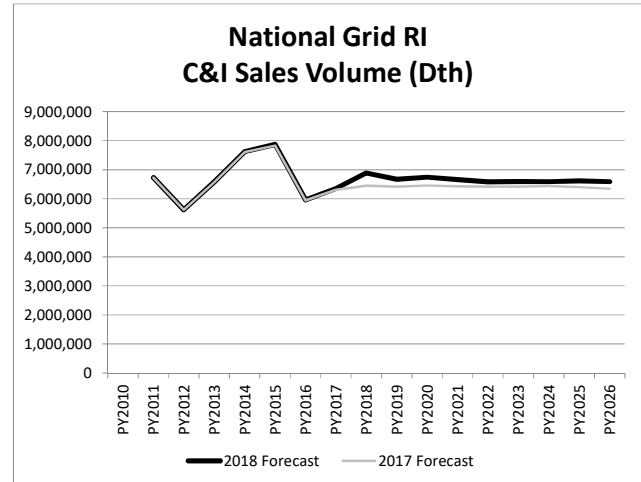
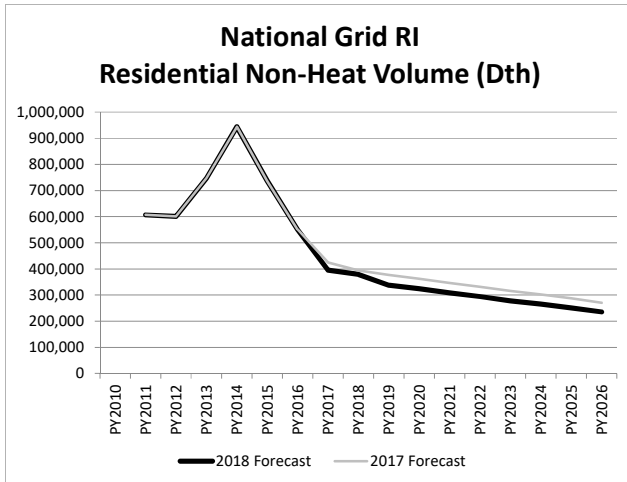
#### 2018 vs 2017 Forecast

2018 National Grid RI Volume Forecast (Dth)  
Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,723,757	7,680,544	2,569,158	35,318,097	2,205,233	37,523,331
PY2012	601,399	14,783,757	5,621,627	7,610,425	2,334,007	30,951,215	2,169,374	33,120,589
PY2013	746,888	17,315,788	6,580,974	8,278,483	3,062,257	35,984,391	1,985,725	37,970,115
PY2014	944,135	19,573,872	7,622,602	8,563,673	3,585,382	40,289,664	1,734,538	42,024,202
PY2015	736,897	20,389,733	7,868,314	9,416,525	3,745,573	42,157,042	1,736,206	43,893,248
PY2016	551,234	16,675,190	5,957,637	8,656,943	3,646,308	35,487,311	1,769,137	37,256,449
PY2017	395,530	18,593,539	6,351,832	8,709,202	4,050,589	38,100,691	1,727,212	39,827,903
PY2018	378,646	19,891,785	6,884,562	8,872,850	4,315,187	40,343,031	1,703,545	42,046,575
PY2019	337,218	19,645,520	6,672,101	8,786,738	4,245,454	39,687,032	1,587,493	41,274,524
PY2020	324,087	19,872,551	6,740,466	8,787,353	4,310,429	40,034,886	1,587,999	41,622,886
PY2021	307,966	20,033,440	6,654,173	8,683,991	4,319,218	39,998,787	1,628,287	41,627,075
PY2022	293,738	20,039,687	6,578,993	8,680,907	4,330,601	39,923,925	1,636,147	41,560,072
PY2023	277,865	20,255,792	6,595,995	8,644,859	4,359,023	40,133,535	1,637,310	41,770,845
PY2024	265,337	20,524,909	6,590,653	8,652,037	4,373,869	40,406,805	1,647,715	42,054,520
PY2025	250,974	20,669,989	6,612,811	8,599,977	4,393,900	40,527,651	1,642,966	42,170,616
PY2026	235,326	20,752,635	6,589,457	8,595,976	4,416,334	40,589,728	1,633,143	42,222,870
PY24/PY19	-4.7%	0.9%	-0.2%	-0.3%	0.6%	0.4%	0.7%	0.4%

2017 National Grid RI Volume Forecast (Dth)  
Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,723,757	7,680,544	2,569,158	35,318,097	2,205,233	37,523,331
PY2012	601,399	14,783,757	5,620,373	7,611,679	2,334,007	30,951,215	2,169,374	33,120,589
PY2013	746,888	17,315,788	6,571,870	8,287,587	3,062,257	35,984,391	1,985,725	37,970,115
PY2014	944,136	19,573,841	7,609,514	8,576,758	3,585,382	40,289,632	1,734,538	42,024,170
PY2015	736,903	20,389,410	7,830,054	9,454,625	3,745,696	42,156,688	1,736,206	43,892,893
PY2016	551,198	16,673,399	5,945,321	8,661,948	3,641,254	35,473,120	1,769,137	37,242,257
PY2017	424,262	18,338,287	6,311,641	9,012,744	4,051,353	38,138,287	1,703,799	39,842,086
PY2018	393,708	19,049,952	6,451,808	9,285,305	4,249,127	39,429,900	1,657,412	41,087,312
PY2019	376,373	19,216,802	6,423,079	9,230,260	4,376,180	39,622,694	1,728,442	41,351,136
PY2020	362,358	19,397,078	6,454,594	9,193,871	4,538,598	39,946,500	1,731,682	41,678,182
PY2021	346,751	19,806,872	6,427,496	9,146,714	4,686,508	40,414,342	1,754,295	42,168,636
PY2022	330,866	19,761,213	6,421,496	9,131,238	4,805,112	40,449,925	1,820,125	42,270,050
PY2023	315,422	20,031,054	6,414,166	9,102,594	4,948,325	40,811,561	1,851,672	42,663,233
PY2024	301,925	20,251,130	6,432,099	9,083,744	5,096,152	41,165,049	1,892,104	43,057,153
PY2025	286,843	20,552,813	6,399,823	9,027,347	5,224,446	41,491,274	1,890,048	43,381,322
PY2026	270,217	20,692,042	6,344,184	9,003,962	5,308,820	41,619,226	1,884,413	43,503,639
PY24/PY19	-4.3%	1.1%	0.0%	-0.3%	3.1%	0.8%	1.8%	0.8%





## Attachment TEP-2

### National Grid RI Retail Meter Count Forecast

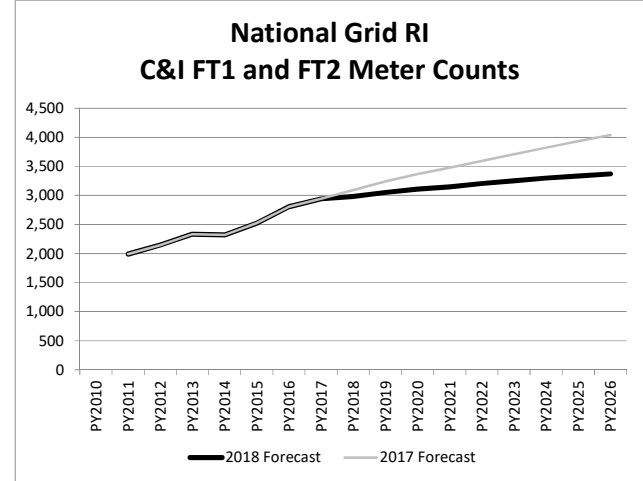
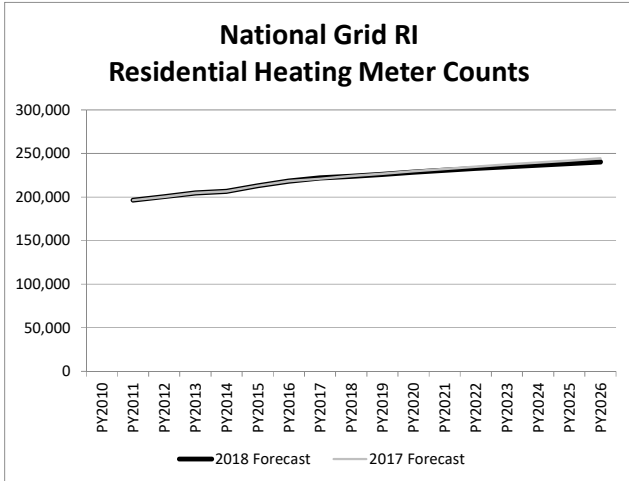
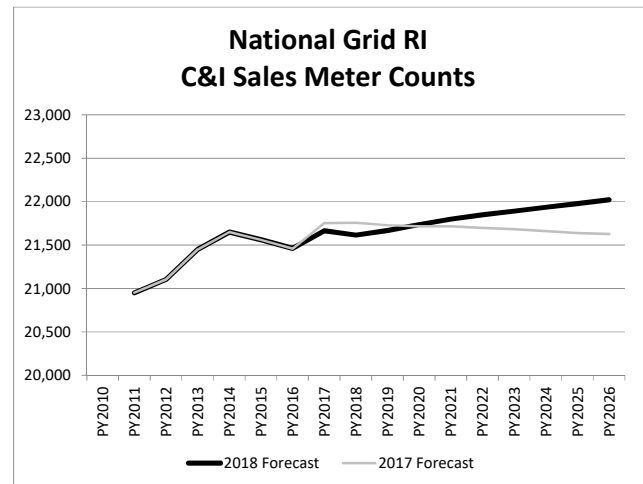
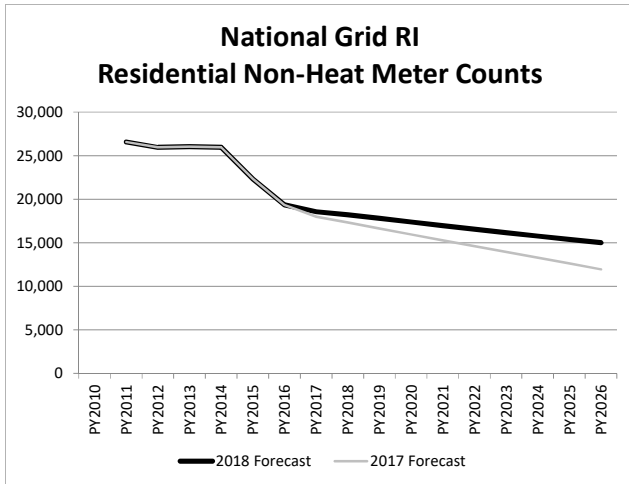
#### 2018 vs 2017 Forecast

2018 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	1,412	249,669	53	249,722
PY2013	26,042	204,520	21,451	721	1,613	254,347	48	254,395
PY2014	25,957	206,567	21,650	699	1,621	256,494	45	256,539
PY2015	22,311	212,896	21,562	684	1,841	259,294	39	259,333
PY2016	19,348	218,305	21,462	674	2,132	261,921	41	261,962
PY2017	18,572	222,014	21,663	644	2,298	265,191	41	265,232
PY2018	18,214	223,810	21,614	634	2,348	266,620	39	266,659
PY2019	17,796	226,216	21,669	629	2,424	268,734	39	268,773
PY2020	17,375	228,517	21,735	627	2,479	270,733	39	270,772
PY2021	16,960	230,711	21,797	628	2,521	272,617	39	272,656
PY2022	16,552	232,804	21,849	628	2,575	274,408	43	274,451
PY2023	16,154	234,808	21,892	625	2,627	276,106	45	276,151
PY2024	15,763	236,732	21,935	625	2,673	277,728	45	277,773
PY2025	15,383	238,582	21,976	622	2,714	279,277	45	279,322
PY2026	15,010	240,366	22,021	622	2,749	280,768	45	280,813
PY23/PY18	-2.4%	1.0%	0.3%	-0.3%	2.3%	0.7%	2.9%	0.7%

2017 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	30	245,955
PY2012	25,955	200,463	21,105	734	1,412	249,669	29	249,698
PY2013	26,042	204,520	21,451	721	1,613	254,347	25	254,372
PY2014	25,958	206,566	21,650	699	1,621	256,494	22	256,516
PY2015	22,312	212,886	21,560	684	1,842	259,284	16	259,300
PY2016	19,333	218,196	21,457	674	2,133	261,793	18	261,811
PY2017	17,989	221,098	21,754	634	2,309	263,784	16	263,800
PY2018	17,314	224,029	21,757	616	2,479	266,195	17	266,212
PY2019	16,634	226,854	21,729	603	2,641	268,461	18	268,479
PY2020	15,947	229,566	21,716	593	2,775	270,597	18	270,615
PY2021	15,282	232,178	21,714	583	2,897	272,654	18	272,672
PY2022	14,619	234,717	21,698	570	3,024	274,628	18	274,646
PY2023	13,954	237,185	21,681	557	3,153	276,530	20	276,550
PY2024	13,287	239,587	21,661	544	3,279	278,358	20	278,378
PY2025	12,619	241,932	21,639	530	3,402	280,122	20	280,142
PY2026	11,950	244,218	21,626	516	3,524	281,834	20	281,854
PY23/PY18	-4.2%	1.1%	-0.1%	-2.0%	4.9%	0.8%	3.3%	0.8%





## Attachment TEP-3

### National Grid RI Economic Forecast

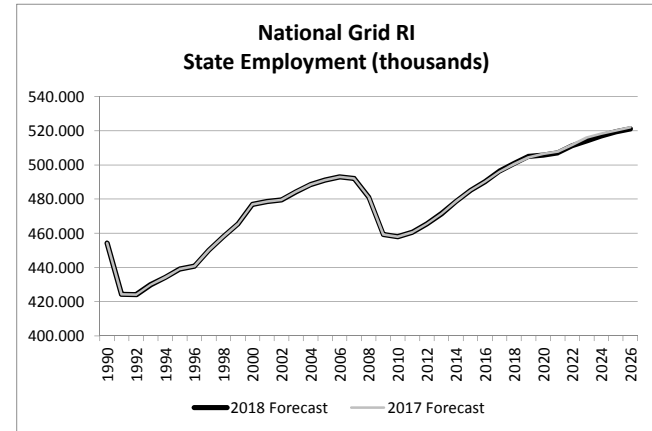
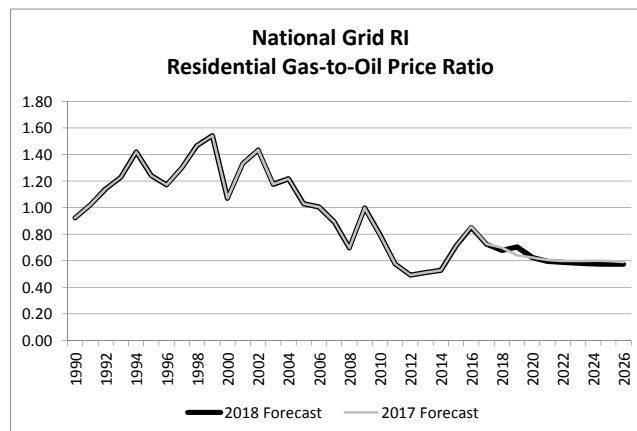
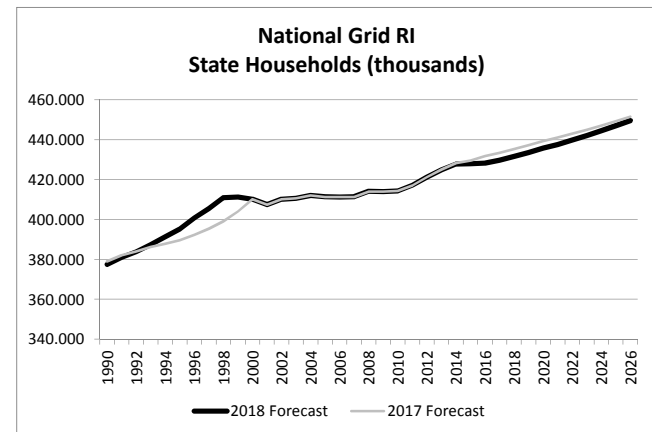
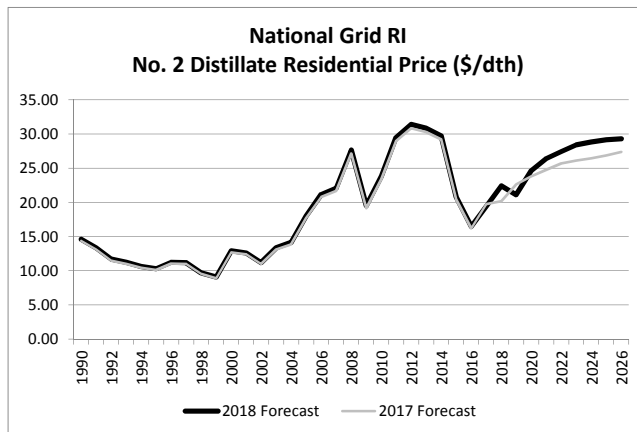
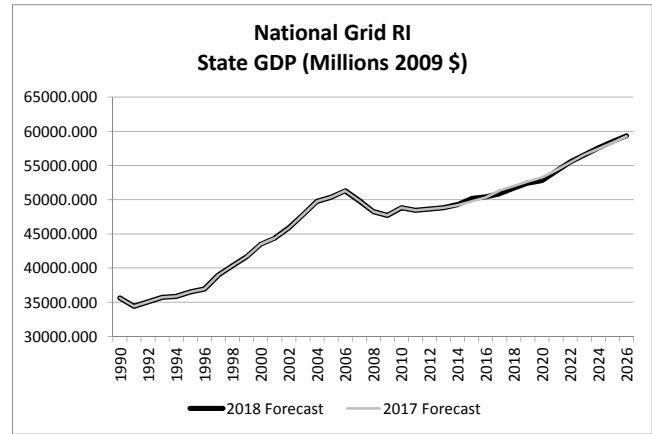
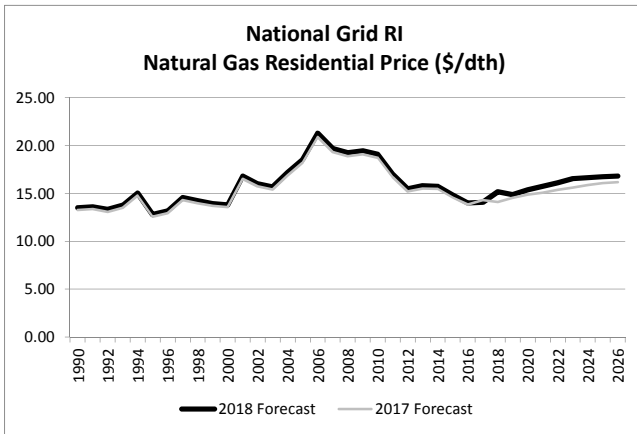
#### 2018 vs 2017 Forecast

2018 National Grid RI Economic Data  
(Prices in 2018 \$/Dth)

	NGPRCR	OILPRCR No 2 Distillate	GORR	GDP	HH	EMPL
	Natural Gas Residential	Residential Price by All Sellers	Residential Gas-to-Oil Price Ratio	GDP (2009 Millions of \$)	Households (thousands)	Non-Farm Employment (thousands)
Year	Price					
1990	13.50	14.60	0.92	35615.834	377.381	454.225
1991	13.62	13.32	1.02	34371.872	380.898	424.283
1992	13.33	11.69	1.14	35062.829	383.703	424.050
1993	13.77	11.20	1.23	35716.351	387.380	429.925
1994	15.06	10.61	1.42	35826.302	391.398	434.208
1995	12.79	10.30	1.24	36504.778	395.112	439.125
1996	13.18	11.25	1.17	36926.285	400.848	440.767
1997	14.58	11.19	1.30	38989.000	405.502	450.058
1998	14.24	9.70	1.47	40360.000	410.961	457.950
1999	13.96	9.05	1.54	41651.000	411.187	465.500
2000	13.82	12.91	1.07	43476.000	410.045	476.908
2001	16.81	12.61	1.33	44388.000	407.452	478.508
2002	16.03	11.17	1.43	45881.000	410.070	479.433
2003	15.68	13.33	1.18	47809.000	410.589	484.275
2004	17.18	14.12	1.22	49763.000	412.074	488.483
2005	18.56	18.01	1.03	50380.000	411.353	491.125
2006	21.29	21.17	1.01	51304.000	411.287	492.983
2007	19.70	22.08	0.89	49838.000	411.381	492.017
2008	19.25	27.64	0.70	48262.000	414.059	481.058
2009	19.45	19.50	1.00	47709.000	414.002	459.350
2010	19.08	23.82	0.80	48803.000	414.331	458.000
2011	17.05	29.51	0.58	48424.000	417.189	460.517
2012	15.49	31.42	0.49	48631.000	421.155	465.433
2013	15.80	30.86	0.51	48815.000	424.831	471.500
2014	15.76	29.73	0.53	49269.000	427.777	478.592
2015	14.85	20.76	0.72	50184.000	427.961	485.142
2016	14.02	16.48	0.85	50433.000	428.223	490.183
2017	14.08	19.44	0.72	50886.712	429.631	496.433
2018	15.19	22.39	0.68	51677.732	431.689	500.860
2019	14.88	21.11	0.71	52419.286	433.525	505.014
2020	15.40	24.62	0.63	52796.829	435.731	505.754
2021	15.75	26.41	0.60	54167.415	437.651	507.058
2022	16.13	27.43	0.59	55500.038	439.823	511.165
2023	16.55	28.41	0.58	56566.757	442.090	514.149
2024	16.66	28.84	0.58	57597.644	444.526	516.967
2025	16.76	29.18	0.57	58523.715	447.122	519.349
2026	16.81	29.28	0.57	59360.774	449.690	521.080
PY23/PY18	1.7%	4.9%	-3.0%	1.8%	0.5%	0.5%

2017 National Grid RI Economic Data  
(Prices in 2017 \$/Dth)

	NGPRCR	OILPRCR No 2 Distillate	GORR	GDP	Households	Non-Farm Employment
	Natural Gas Residential	Residential Price by All Sellers		(2005 Millions of \$)	(thousands)	(thousands)
Year	Price	Sellers				
1990	13.26	14.34	0.92	35615.771	378.930	454.225
1991	13.37	13.08	1.02	34371.943	381.950	424.283
1992	13.09	11.48	1.14	35062.800	383.960	424.050
1993	13.52	11.00	1.23	35716.335	386.209	429.925
1994	14.78	10.41	1.42	35826.380	387.830	434.208
1995	12.56	10.12	1.24	36504.762	389.537	439.125
1996	12.94	11.04	1.17	36926.368	392.354	440.767
1997	14.31	10.99	1.30	38989.000	395.405	450.058
1998	13.98	9.52	1.47	40360.000	398.997	457.950
1999	13.70	8.89	1.54	41651.000	403.951	465.500
2000	13.57	12.67	1.07	43476.000	410.045	476.908
2001	16.50	12.38	1.33	44388.000	407.441	478.508
2002	15.74	10.97	1.43	45881.000	410.048	479.433
2003	15.40	13.08	1.18	47809.000	410.555	484.275
2004	16.87	13.86	1.22	49763.000	412.028	488.483
2005	18.22	17.68	1.03	50380.000	411.296	491.125
2006	20.90	20.79	1.01	51304.000	411.219	492.983
2007	19.34	21.68	0.89	49838.000	411.301	492.017
2008	18.90	27.14	0.70	48262.000	413.966	481.058
2009	19.10	19.15	1.00	47709.000	413.913	459.350
2010	18.73	23.39	0.80	48803.000	414.285	458.000
2011	16.74	28.97	0.58	48424.000	417.094	460.517
2012	15.20	30.84	0.49	48631.000	421.216	465.433
2013	15.52	30.30	0.51	48815.000	425.041	471.500
2014	15.47	29.19	0.53	49210.000	428.212	478.592
2015	14.58	20.38	0.72	49738.000	429.591	485.142
2016	13.86	16.18	0.86	50327.000	431.837	490.183
2017	14.31	19.73	0.73	51329.438	433.410	496.024
2018	14.11	20.18	0.70	52012.470	435.339	500.497
2019	14.54	22.62	0.64	52665.851	437.173	504.477
2020	14.87	23.77	0.63	53276.505	439.296	506.575
2021	15.08	24.78	0.61	54294.337	441.129	507.817
2022	15.37	25.71	0.60	55444.328	443.097	511.697
2023	15.62	26.12	0.60	56551.884	445.035	516.027
2024	15.87	26.44	0.60	57445.270	447.102	518.347
2025	16.09	26.87	0.60	58337.461	449.329	520.112
2026	16.17	27.38	0.59	59275.819	451.528	522.040
PY23/PY18	2.0%	5.3%	-3.1%	1.7%	0.4%	0.6%



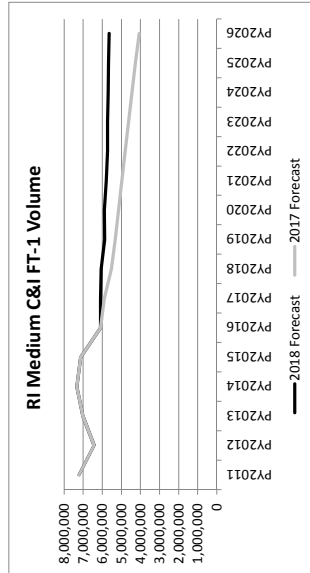
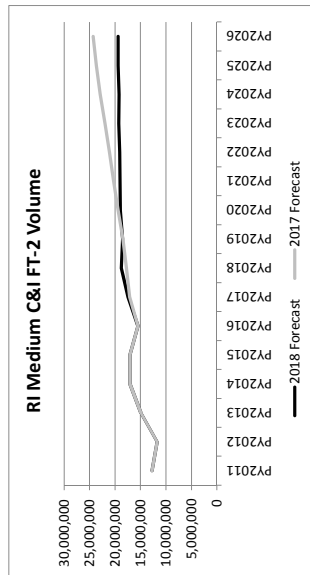
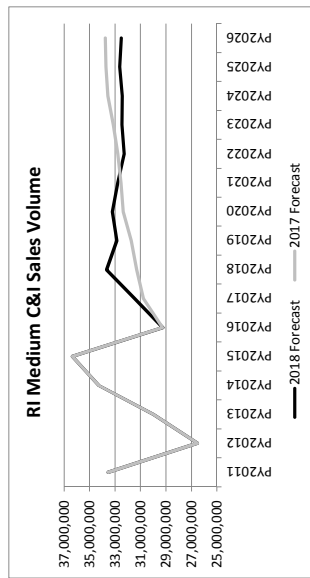
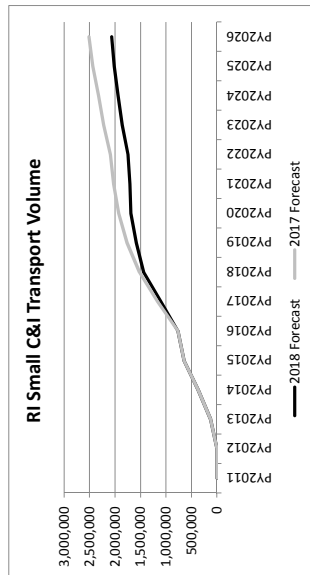
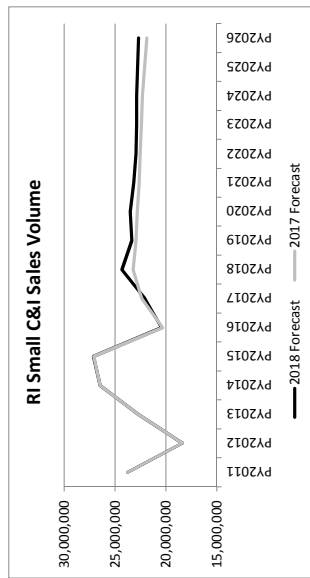
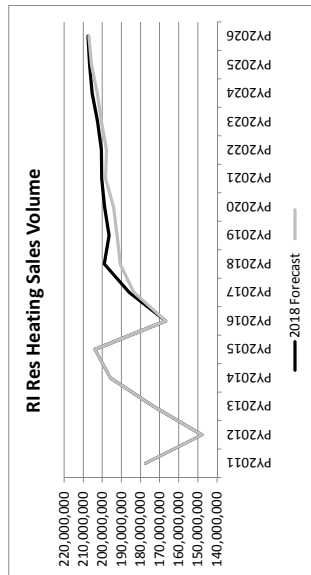
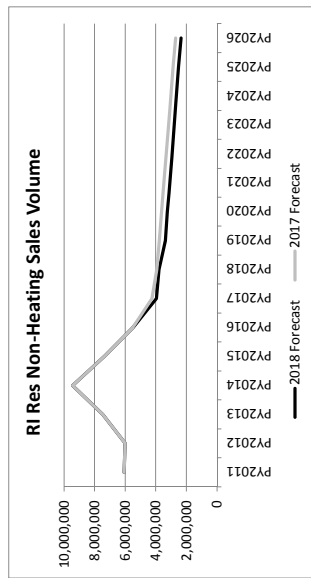


## Attachment TEP-4

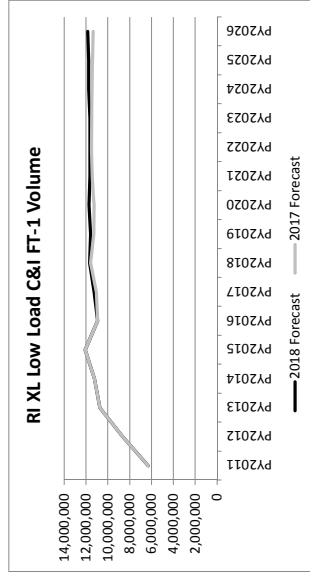
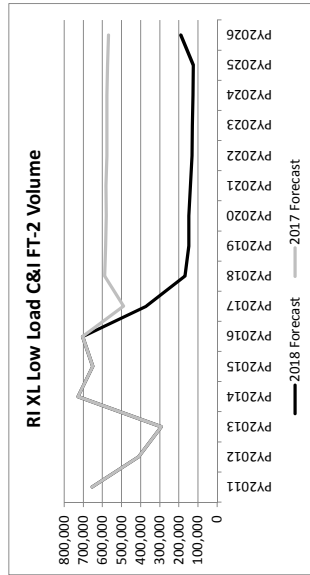
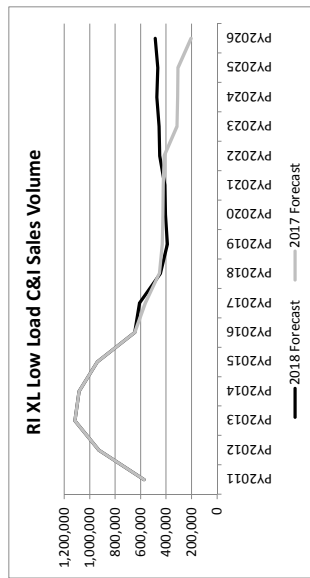
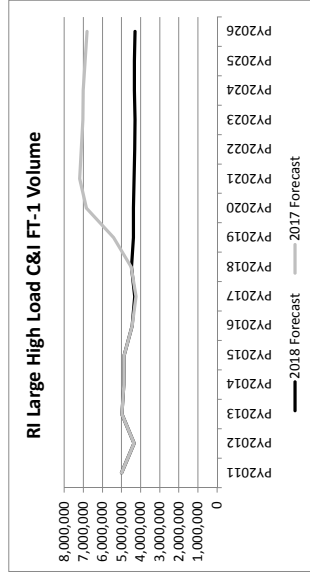
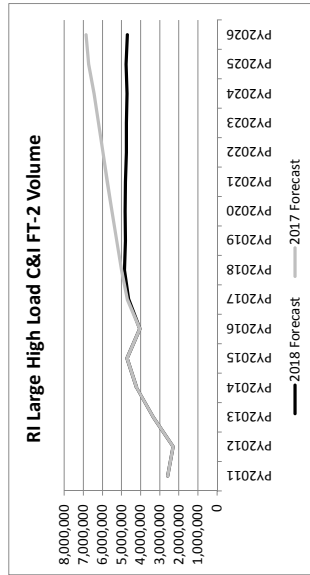
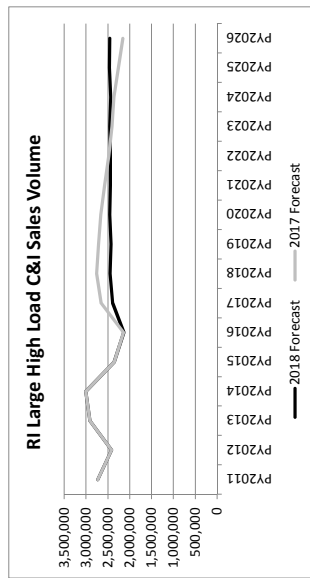
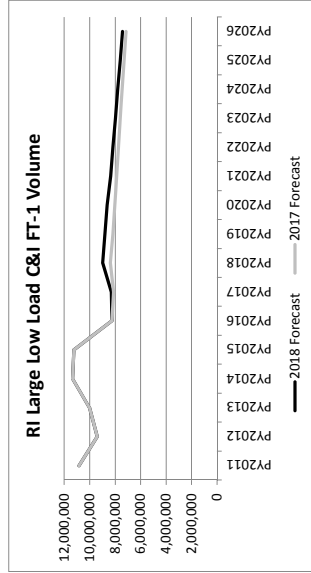
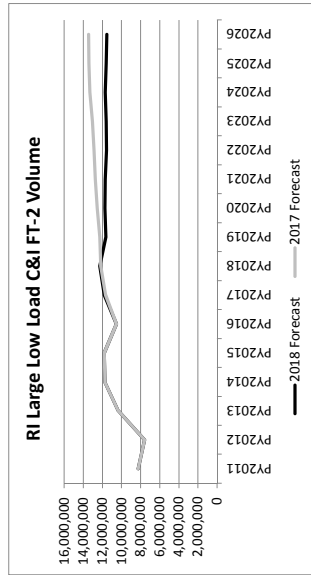
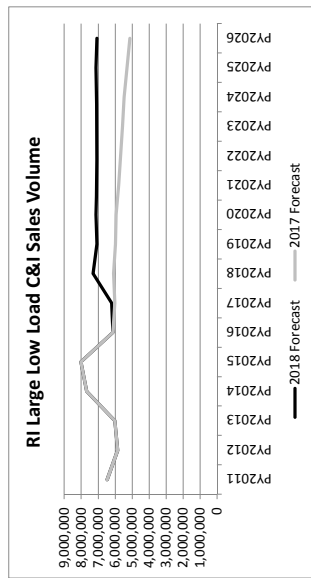
### National Grid RI Retail Volume Forecast by Rate Class

#### 2018 vs 2017 Forecast

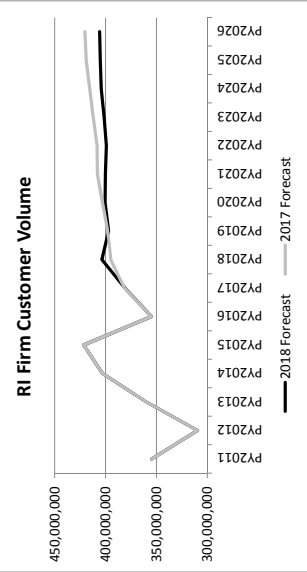
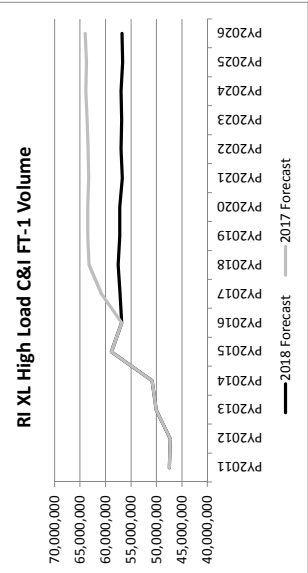
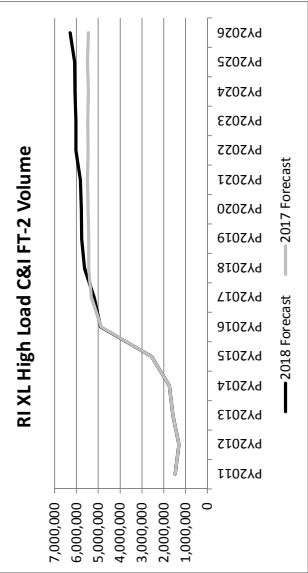
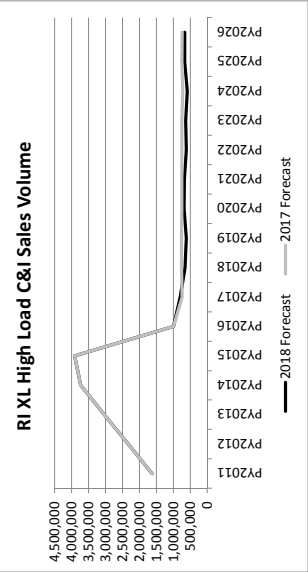
National Grid  
2018 and 2017 Volume Forecasts by Rate Class  
(Therms; Planning Year)



National Grid  
2018 and 2017 Volume Forecasts by Rate Class  
(Therms; Planning Year)



National Grid  
2018 and 2017 Volume Forecasts by Rate Class  
(Therms; Planning Year)



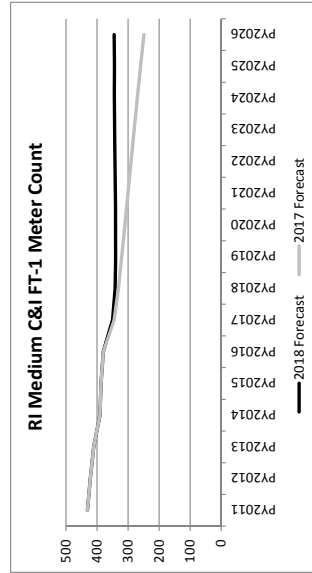
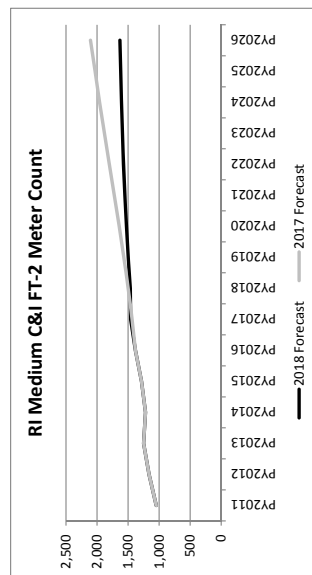
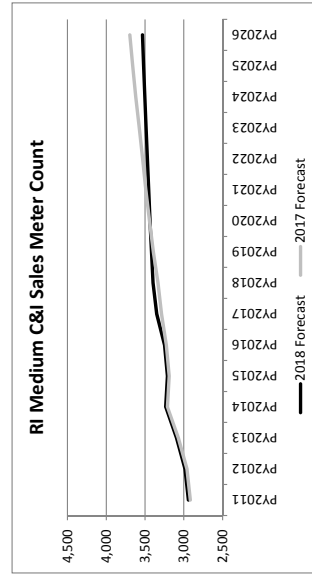
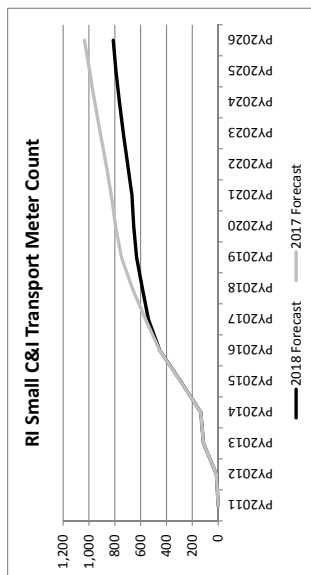
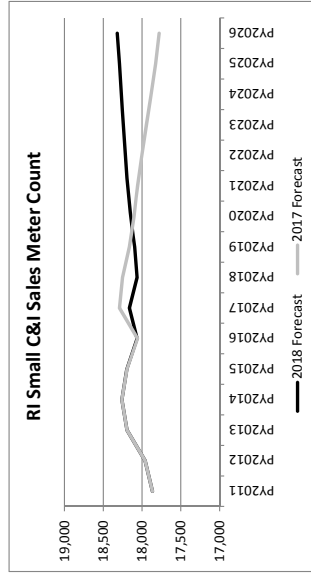
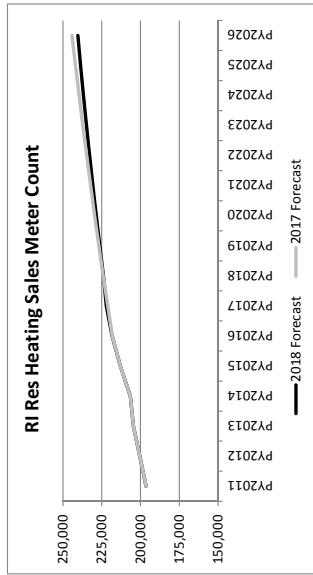
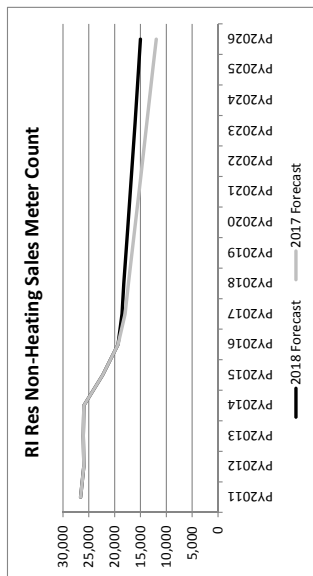


## Attachment TEP-5

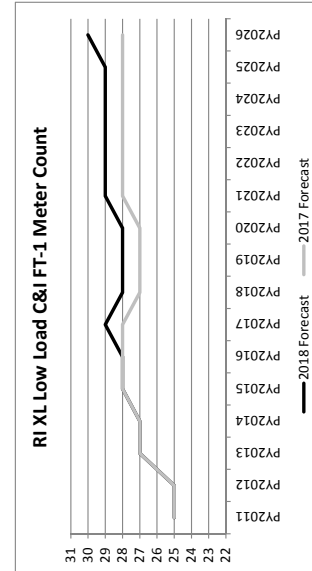
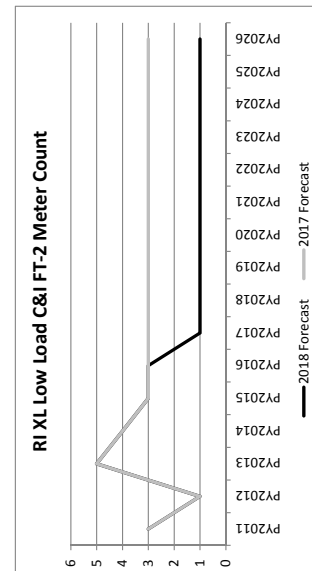
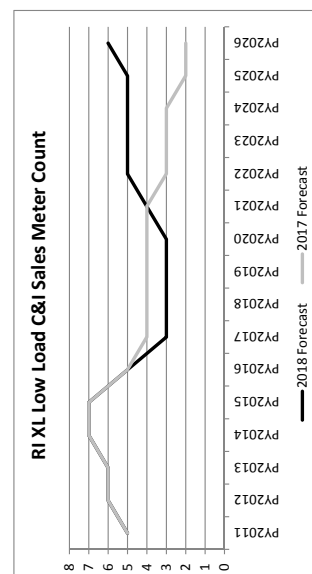
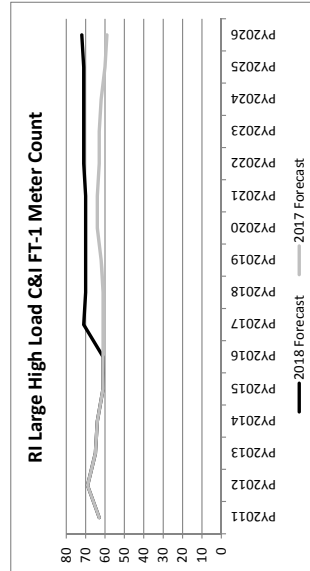
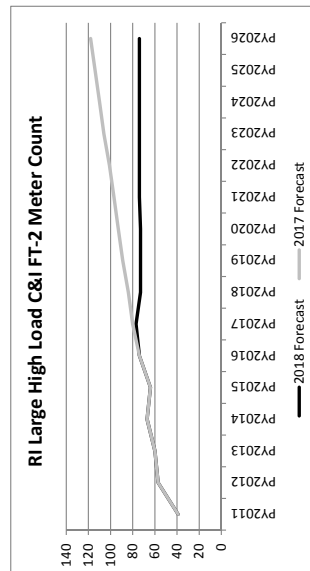
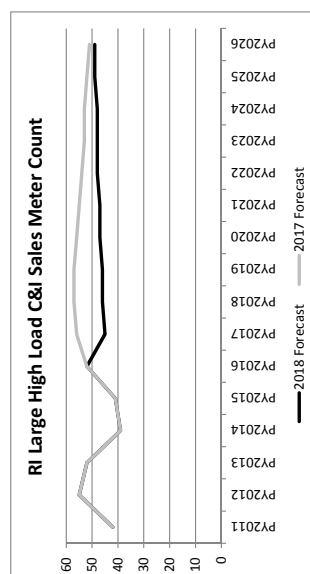
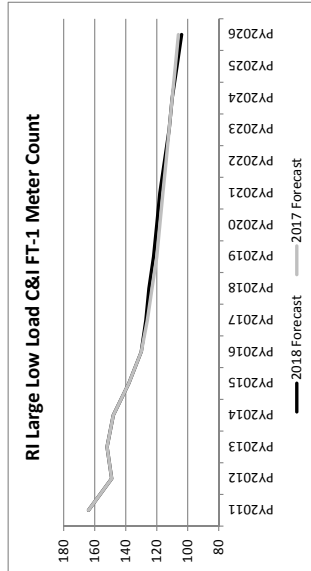
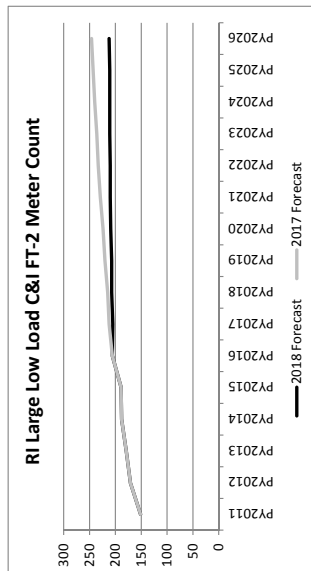
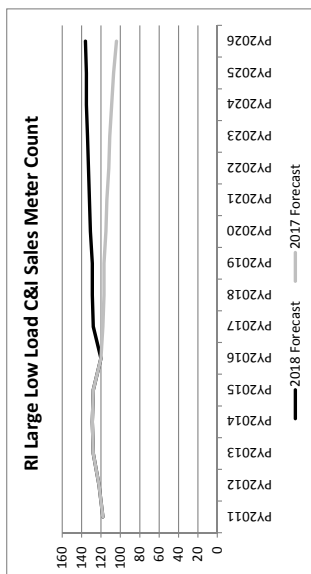
### National Grid RI Retail Meter Count Forecast by Rate Class

#### 2018 vs 2017 Forecast

National Grid  
2018 and 2017 Meter Count Forecasts by Rate Class  
(end of Planning Year)



National Grid  
2018 and 2017 Meter Count Forecasts by Rate Class  
(end of Planning Year)



National Grid  
2018 and 2017 Meter Count Forecasts by Rate Class  
(end of Planning Year)

