nationalgrid

September 1, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4647 - 2016 Gas Cost Recovery Filing

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] annual Gas Cost Recovery (GCR) filing, which is being submitted pursuant to the Gas Cost Recovery Clause found in the Company's tariffs at RIPUC NG-Gas No. 101, Section 2, Schedule A. The proposed rates contained in this GCR filing reflect the customer class-specific factors necessary for the Company to collect sufficient revenues to recover projected gas costs for the period November 1, 2016 through October 31, 2017.

This filing consists of the pre-filed testimony and attachments of Elizabeth D. Arangio, Ann E. Leary, Theodore E. Poe, Jr., and Stephen A. McCauley. Ms. Arangio provides testimony relative to the Company's projected gas costs in support of the Company's proposed GCR factors, as well as to modifications to the Company's gas supply portfolio for the 2016 GCR period. Ms. Leary's testimony describes the development of the GCR charges proposed for effect November 1, 2016 and provides a bill impact analysis relative to those proposed rates. Mr. Poe's testimony provides support for the underlying wholesale and retail forecasts that the Company uses to estimate gas costs in this filing. Mr. McCauley discusses the results of the Gas Procurement Incentive Plan for the period July 1, 2015 through June 30, 2016. He also discusses the results of the Natural Gas Portfolio Management Plan for the period April 1, 2015 through March 31, 2016 and the recommendation to continue with that plan for an additional year.

As described in Ms. Leary's testimony, based on the GCR rates proposed for effect November 1, 2016 through October 31, 2017, an average residential heating customer using 846 therms per year will experience a total bill decrease related to the proposed GCR and Distribution Adjustment Charge (DAC) rates of approximately $22.94, or an annual 2.0 percent decrease from the current existing rates. This decrease is comprised of a decrease of $69.51 in the GCR-related costs; an increase of $47.26 in DAC-related costs, which was filed on September 1, 2016 under separate cover in Docket No. 4634; and a decrease of $0.69 in Gross Earnings Tax.

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

280 Melrose Street, Providence, RI 02907
T: 401-784-7000 ■ www.nationalgrid.com

This filing also contains a Request for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of certain confidential gas-cost pricing information and forecasts, which are provided in Attachments EDA-1, EDA-2, and EDA-4 to Ms. Arangio's testimony, as well as in Attachments AEL-1 and AEL-2 to the testimony of Ms. Leary. Accordingly, the Company has provided the PUC with the un-redacted confidential materials for its review, and has included redacted copies of these materials in the filing.

Thank you for your attention to this filing. If you have any questions, please contact Jennifer Brooks Hutchinson at 401 784-7288 or Robert Humm at 401-784-7415.

Very truly yours,

Jennifer Brooks Hutchinson

Robert J. Humm

Enclosures

cc: Leo Wold, Esq.
Steve Scialabba, Division
Bruce Oliver, Division

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2016	)	Docket No. 4647

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID'S REQUEST FOR PROTECTIVE
TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Rule 1.2(g) of the PUC's Rules of Practice and Procedure 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 September 1, 2016, National Grid filed with the PUC its Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. The GCR filing includes confidential gas-cost pricing information and forecasts, which are provided in Attachments EDA-1, EDA-2, and EDA-4 to the pre-filed direct testimony of Elizabeth D. Arangio, and in Attachments AEL-1 and AEL-2 to the pre-filed direct testimony of Ann E. Leary. In accordance with Rule 1.2(g)(3), National

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

II. LEGAL STANDARD

The PUC's Rule 1.2(g) 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 to be confidential and to protect that information from public disclosure.

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

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

The Rhode Island Supreme Court has held that this confidential information exemption applies where 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. *See Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I.2001).

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

III. BASIS FOR CONFIDENTIALITY

The gas-cost pricing information and forecasts, which are provided in Attachments EDA-1, EDA-2, and EDA-4 to the testimony of Ms. Arangio and in Attachments AEL-1 and AEL-2 to the testimony of Ms. Leary, are confidential and privileged information of the type that National Grid would not ordinarily make public. Moreover, public disclosure of such information could impair National Grid's ability to obtain advantageous pricing in the future, thereby causing substantial competitive harm. Accordingly, National Grid seeks protection for such confidential information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its request for protective treatment of confidential information.

Respectfully submitted,

NATIONAL GRID

By its attorneys,

Jennifer Brooks Hutchinson, Esq. (#6176)
Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7288
(401) 784-7415
Dated: September 1, 2016

The Narragansett Electric Company
d/b/a National Grid

2016 GAS COST RECOVERY

Testimony and Attachments of:

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

September 1, 2016

Submitted to:

Rhode Island Public Utilities Commission
RIPUC Docket No. 4647

Submitted by:

nationalgrid

Filing Letter

nationalgrid

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Dated: September 1, 2016

Testimony of
Elizabeth D. Arangio

DIRECT TESTIMONY

OF

ELIZABETH D. ARANGIO

September 1, 2016

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I. Introduction

Q. Please state your name and business address.

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

Q. What is your position and responsibilities within that position?

A. I am the Director of Gas Supply Planning. In this position, I am responsible for the resource portfolio of the New England local gas distribution companies (LDCs) that operate as Boston Gas Company, Colonial Gas Company and The Narragansett Electric Company, each d/b/a National Grid. In addition to the New England portfolios, I am also responsible for gas supply planning for the resource portfolios of The Brooklyn Union Gas Company, KeySpan Gas East Corporation and Niagara Mohawk Power Corporation, which are all located in New York. For purposes of this testimony, references to the "Company" relate solely to The Narragansett Electric Company.

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

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Arts in Business Administration. In 1995, I graduated from Bentley College with a Masters of Business Administration. From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In

1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services, 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 was named to my current position with the added responsibility for the National Grid gas resource portfolios in upstate New York and 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 in regulatory proceedings?

A. Yes. I have recently testified before the Rhode Island Public Utilities Commission (PUC) in support of the Company's 2015 Gas Cost Recovery (GCR) filing (Docket No. 4576), and Gas Customer Choice Program (Docket Nos. 4520 and 4523), and the Natural Gas

Portfolio Management Plan (NGPMP) (Docket No. 4038). In the past, I have testified numerous times before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission. In addition, I have also presented information to the State of New York Department of Public Service.

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

A. My testimony provides support for the estimated gas costs, assignments of pipeline capacity to marketers, and other issues relating to the Company's proposed 2016-17 GCR factors. In addition, my testimony discusses modifications that the Company has made to the portfolio for the 2016 GCR period.

Q. Are you sponsoring attachments to your testimony?

A. Yes. I am sponsoring the following attachments:

EDA-1 Summary of Projected Gas Costs – **CONFIDENTIAL Information**
EDA-2 Gas Cost Details – **CONFIDENTIAL Information**
EDA-3 NYMEX Strip Comparison
EDA-4 Assignment of Pipeline Capacity – **CONFIDENTIAL Information**
EDA-5 FT-2 Operational Parameters
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 NYMEX strip as of the close of trading on July 29, 2016 and (2) the difference between the futures contract purchases under the Gas Procurement Incentive Plan (GPIP) as of July 29, 2016 and the July 29, 2016 NYMEX strip. The GCR factors also reflect storage and inventory costs as of July 29, 2016, as well as the projected cost of purchasing gas ratably through the remainder of the injection season, as provided for in the NGPMP. Attachment EDA-1 provides a summary of gas costs by major cost categories. Attachment 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 EDA-3 is a graph that compares NYMEX pricing from July 31, 2015 utilized in the Company's GCR filing last year to NYMEX pricing from July 29, 2016 used in this instant filing. The July 29, 2016 NYMEX strip is on average $0.259, or 8.4%, higher compared to the July 31, 2015 NYMEX strip during the peak season of November through March. During the off-peak season of April through October, the July 29, 2016 NYMEX strip is on average $0.069, or 2.3%, higher compared to the July 31, 2015

NYMEX strip. Overall, the July 29, 2016 NYMEX strip is an average of $0.148, or 4.9%, higher compared to the July 31, 2015 NYMEX strip.

Q. Please describe how gas costs are calculated.

A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT® Model to perform a dispatch optimization of the entire Rhode Island portfolio of gas supply, pipeline transportation, underground storage and peaking supplies. SENDOUT® allows the Company to determine the optimal dispatch of its existing resources subject to contractual and operating constraints to minimize the cost of supply over the year. The pricing of various pipeline services is based directly on the pipeline tariffs and the rates in effect as of August 1, 2016. For purchases at locations other than the Henry Hub, the model uses the expected basis differential to the Henry Hub prices to determine the expected difference or "basis."

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

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

1. The Supply Fixed Cost Component includes all fixed costs related to the purchase, storage, or delivery of firm gas, including, but not limited to, pipeline and supplier fixed reservation costs, demand charges, and transportation fees.
2. 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, transportation fees, 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 2016 through October 2017 is shown on Attachment EDA-1.

Q. Please describe Attachment EDA-2, pages 1 through 17.

A. Attachment EDA-2 shows the supporting detail for gas costs included in the filing for the period November 2016 through October 2017. The first two pages show the optimized, forecasted sendout by supply source under normal weather from the SENDOUT® model, as well as the detailed makeup of supply by pipeline source, storage contract and peaking facility. The next section, pages 3 through 6, shows the calculation of the unitized delivered cost for each pipeline path based on the July 29, 2016 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 (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 liquefied natural gas (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 LNG suppliers. Charges for the LNG 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. On Attachment EDA-2, page 3, the second supply source shown is gas purchased on the Tennessee Pipeline in Zone 0, located in South Texas. The calculation for November begins with the $3.076 NYMEX price, which is then adjusted for basis by, in this case, subtracting $0.098. This reflects the forward basis strip for gas supply in South Texas delivered into Tennessee Pipeline. Next, the price is adjusted to reflect the fuel retention percentage of the pipeline, 3.05%, to bring the price to $3.072. That adjustment is made by dividing the price by one minus the loss factor, 0.9695, effectively adjusting the

commodity price to incorporate the fact that only 96.95% of the supply delivered from the pipeline in South Texas will be delivered to Rhode Island. The pipeline usage fee of $0.3352 is then added to reflect the cost of transportation on the pipeline, resulting in a delivered cost of $3.4069 per Dth.

III. Gas Supply Portfolio

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

A. As previously described in Docket No. 4576**,** the Company continues to operate the portfolio similarly to its operations during the 2015-16 gas year. 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 Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company's citygates on Algonquin Gas Transmission (Algonquin), as well as the 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. How will the Company supply the Dawn, Ontario Canada capacity path for the 2016-17 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 Dawn, Ontario in Canada and delivers into TransCanada at Parkway. In addition, the Company has firm capacity entitlements of 1,012 Dth per day on the TransCanada pipeline system. This capacity path originates at the interconnection with Union Gas at Parkway and delivers into Iroquois Gas Transmission (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 Pipeline.

The Company issued a request for proposal (RFP) on July 25, 2016 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, 2016. The RFP requested a maximum daily quantity of 1,025 Dth per day of with a swing component for the months of November 2016 and March 2017 and a baseload volume for the months of December 2016, January 2017 and February 2017. The Company is in the process of finalizing an AMA to provide the Company with supply at the Canada-United States border at Waddington, New York. 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.

Q. What are the Company's plans for the Company's existing HubLine and East-to-West capacity paths on Algonquin?

As mentioned in previous filings, the Company has contracted for 18,000 Dth per day of capacity from the Algonquin Incremental Market Expansion (AIM) Project. The Company's 18,000 Dth per day of AIM capacity represents the sum of the Company's existing HubLine and East-to-West capacity on Algonquin. As of the in-service date of the AIM Project, these existing contracts will terminate.

Q. Please provide an update for the AIM Project.

A. The AIM Project is on schedule with an expected in-service date of November 1, 2016.

Q. Have there been any changes to the portfolio since last year that should be noted?

A. Yes. The following two events have occurred over the last year, which have prompted changes to the gas supply portfolio for the upcoming winter: (1) the Texas Eastern Transmission Company (Texas Eastern) incident, which occurred downstream of the Delmont Compressor Station in Westmoreland County, Pennsylvania on April 29, 2016;

and (2) the Company has taken its Cumberland LNG tank out of service for the 2016-17 winter season. Both of these events have required additional resources to be added to the portfolio.

Q. Please provide the chronology of events associated with the Texas Eastern incident (Incident) that occurred downstream of the Delmont Compressor Station in Westmoreland County, Pennsylvania.

A. 04-29-16:
The Incident occurred at 8:13 a.m. in Salem Township, PA on the Texas Eastern natural gas pipeline. There are four parallel Texas Eastern lines in this right-of-way. All of the lines were isolated within an hour of the incident. This section of pipe is 30 inches in diameter, and was built in 1981. An inline inspection in 2012 revealed no areas requiring repair or remediation before the next inspection.

05-04-16:
Spectra Energy received a corrective action order from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding the Incident. According to the corrective action order:

> The cause of failure is unknown at this time, and the investigation is ongoing. The failed pipe section is being transported to an independent metallurgist for examination and failure analysis. The preliminary investigation has identified evidence of corrosion along two of the circumferential welds: one at the point of failure and another excavated after PHMSA's response to the Failure Site. The pattern of corrosion indicates a possible flaw in the coating material applied to girth weld joints following construction welding procedures in the field at that time.

05-05-16:
The affected line and the three other lines in the vicinity remained shut-in.

05-09-16:
Work to examine and confirm the integrity of one of the three lines in the vicinity of the Incident was completed. This work included uncovering the line to verify that there was

no damage to the pipe from the Incident. The results showed that this line was not affected by the Incident, and the U.S. Department of Transportation has authorized its restart and line has been put back into operation. The other lines in the vicinity remain shut-in, including the line involved in the Incident.

06-10-16:
As previously mentioned, Texas Eastern experienced an unplanned outage downstream of its Delmont Compressor Station and repair efforts to restore capacity were continuing. The date on which the return to full capacity will occur through the Delmont Compressor Station remained unknown. Consistent with the information set forth as of May 9, 2016, physical capacity totaling approximately 1,162 MDth per day through this location became available beginning on Gas Day May 10, 2016 and continued to be available thereafter, and Texas Eastern was accepting nominations for deliveries through Delmont up to the stated physical capacity limit (the design capacity through Delmont is 2.7 Bcf/day). In addition, Texas Eastern has accepted nominations for deliveries through Delmont at levels above the stated physical capacity through Delmont, to the extent those deliveries could be accomplished by other operational means.

06-30-16:
As a conservative and precautionary measure, Spectra Energy voluntarily conducted a thorough assessment along the entire Penn-Jersey pipeline system – which consists of four parallel pipes and runs from Delmont, PA, to Lambertville, NJ – to confirm the system's integrity. This assessment included reviewing inspection data, evaluating construction records, performing field investigations, and scheduling additional interior and exterior inspections. These field investigations included uncovering the pipeline in certain locations to inspect it from the outside. Texas Eastern is executing on a plan designed to return to full service by November 1, 2016 and expects the root cause analysis will likely be completed by late summer or early fall.

09-01-16:
Texas Eastern will be holding an operations meeting with meter operators in Texas Eastern's M3 and downstream on Algonquin on Thursday, September 1, 2016, to update customers on the work plan to restore the Penn-Jersey system. The following topics will be addressed: (1) Overall work plan; (2) Status of permits and other critical path items; (3) Illustrative capacity restoration scenarios.

Q. Please describe the supply impacts experienced by the Company as a result of the Incident.

A. On April 29, 2016, Texas Eastern declared a force majeure and subsequently notified shippers that nominations scheduled for Gas Day April 29 through the Delmont Compressor Station on the Penn-Jersey Line were being reduced to 0 Dth per d until further notice in accordance with curtailment procedures in Texas Eastern's Federal Energy Regulatory Commission (FERC) gas tariff. From a supply standpoint, the Company's baseload nominations and injections for May were affected until May 10, 2016. The Company was able to re-route most of the impacted supply and made up the affected injections throughout the month of May. Since May, the Company has secured supplies so as to avoid the restrictions, and has not experienced any further supply interruptions.

Q. What contingency plans has the Company put in place for this winter to account for the potential continuation of the unplanned Delmont Outage?

A. Texas Eastern is committed to restoring full service by November 1, 2016. Despite this fact, the Company is implementing a contingency plan, should there be continued restrictions of primary firm capacity during the winter season. Specifically, the Company issued a RFP on August 11, 2016 seeking the option for a supply call at Texas Eastern/M3 (downstream of the Delmont compressor station) for a term of three months

(December 2016, January 2017 and February 2017) to account for potential expected level of interruption on Texas Eastern. The RFP indicated that on any day during the term, Buyer (the Company) shall have the right, but not the obligation, to call on a maximum daily quantity. The Company estimated the potential supply interruption volume through Delmont based on contract entitlements, its experience during the few weeks following the Incident, and the results of a flow study developed internally using available Texas Eastern pressure and capacity information. In summary, the Company is planning for an interruption of up to 20,000 Dth per day which equates to 40% of its firm capacity entitlements that flow through Delmont, and is in the process of finalizing contracts with suppliers awarded pursuant to the RFP.

Q. What is the status of the Company's Cumberland LNG Facility?

A. During a routine inspection in early spring, the Company's LNG operations identified a temperature anomaly at the bottom of the LNG tank. Out of an abundance of caution, and with safety as the top priority, the Company has taken the facility out of service for the 2016-17 winter season. The Cumberland tank has historically provided up to 30,000 Dth per day and 80,000 Dth per season.

Q. What contingency plans is the Company putting in place for this winter to account for the loss of the Cumberland LNG facility?

A. The Company has secured an incremental 24,000 Dth per day of pipeline capacity on the Tennessee Pipeline for the period November 1, 2016 through October 31, 2017 from Dracut, MA to the Company's citygate in Lincoln, RI. The Company negotiated the term of the capacity for one year, but maintains a "right of first refusal" on the capacity, meaning the Company can secure it for next year (Nov. 2017-Oct. 2018) should the capacity still be needed. The Tennessee Pipeline must be notified of this decision one year in advance, by October 31, 2016. In addition, in order to meet forecasted peak day and peak hour customer requirements during the 2016-17 winter season, the Company will utilize portable LNG with up to seven truckloads on the peak day.

Q. What are the Company's plans to supply the existing and new Dracut Capacity for the 2016-17 year?

A. The Company issued a RFP on August 11, 2016 to purchase supply at Dracut for a term of four months (December 2016, January 2017, February 2017 and March 2017). 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. The RFP requested a maximum daily quantity of 39,000 Dth per day (15,000 Dth per day of existing Dracut capacity plus 24,000 Dth per day of new Dracut capacity) for a maximum seasonal quantity of 1,092,000 Dth. The Company accepted and awarded the bid for the

total supply package to a shipper holding a large position on Maritimes and is in the process of finalizing the purchase agreement.

Q. Has the Company arranged for firm liquid service for the portable LNG needed during the 2016-17 peak season?

A. The Company is in the process of executing an arrangement for liquid service with ENGIE Gas & LNG LLC (ENGIE) for up to 7 truckloads per day and a total of 22 truckloads during the winter season.

Q. How will the Company fill its remaining LNG facilities during the 2017 off-peak refill season?

A. The Company will utilize its existing multi-year arrangements with ENGIE and Gaz Metro LNG, L.P. (Gaz Metro). The arrangement with ENGIE provides for up to 508,000 Dth and the arrangement with Gaz Metro provides for up to 190,500 Dth. The Company plans to have the LNG facilities 100% full as of December 1, 2016.

Q. Given the current landscape of the natural gas market in New England, what is the Company doing to address long-term portfolio needs?

A. To address the changing gas supply landscape and to ensure its ability to continue to reliably serve its existing customer requirements as well as anticipated growth, the Company continues to pursue the following pipeline capacity and LNG solutions.

Pending Pipeline Transportation Agreements:

Algonquin Crary Street Project (Crary Street Project)

The Company has entered into a Precedent Agreement with Algonquin for firm natural gas transportation capacity on its existing Manchester Street lateral off of the Algonquin mainline to a new meter station. The new meter station will be constructed and owned by Algonquin, and will be sized to move up to 96,000 Dth per day. This new citygate station will provide enhanced reliability for the Company's distribution system as it will allow for a new feed into the system at higher pipeline pressures. Furthermore, during the shoulder seasons, it will eliminate the need to rely on LNG to maintain system pressures before it would otherwise be needed to meet customer load. Algonquin will provide service under its AFT-CL Rate Schedule. This project has an expected in-service date of November 1, 2017.

Millennium Eastern System Upgrade Project (Millennium Project)

The Company has entered into a Precedent Agreement for 9,000 Dth per day as part of the Millennium Project for an initial term of 15 years with service expected to commence

by September 1, 2018. The Company's 9,000 Dth per day of Millennium capacity represents half of the Company's AIM Project volume. The Millennium Pipeline begins in Independence, New York (Steuben County, in southwestern New York) and terminates in Buena Vista, New York (Rockland County, near the Hudson River, just north of the New Jersey border). It passes through southern New York, just north of the Pennsylvania border, and accesses gas supplies from the prolific Marcellus Shale production area in northeastern Pennsylvania. The Millennium Pipeline has interconnections with several storage fields and a number of pipelines, including: National Fuel; Columbia Gas Transmission; Dominion Transmission, Inc.; the Laser NE Gathering System, a Marcellus Shale gathering system in northeastern Pennsylvania owned by an affiliate of Transcontinental Gas Pipeline; the Bluestone Gathering System, a fully-owned subsidiary of DTE Energy; and the Central New York Oil and Gas system, which operates the Stagecoach Storage facility and a pipeline that connects the Millennium system with the Tennessee 300 Line and the Transco Leidy Line. The Millennium system currently has approximately 821,000 Dth per day of primary firm delivery point capacity to Algonquin at Ramapo, New York. The Millennium Project is designed to expand facilities to bring an additional 223,000 Dth per day of East Pool supplies to Millennium's interconnection with Algonquin at Ramapo. The Millennium Project will provide the Company with the opportunity to directly secure a cost effective domestically produced source of supply.

LNG Liquefaction Service Agreements:

National Grid LNG (NGLNG)

The Company has entered into a Precedent Agreement for up to 2,616 Dth per day and 507,504 Dth per refill season for a term of 20 years commencing for liquefaction services at NGLNG's currently-existing storage facilities located in Providence, Rhode Island. The liquefaction facilities have an expected in-service date of April 1, 2019. The Company will utilize its existing Algonquin capacity to transport volumes to the proposed liquefaction facility during off-peak periods. Currently, the Company has a storage agreement with NGLNG for LNG storage at the Providence site pursuant to an agreement dated November 30, 1998. This agreement is not expected to change. The liquefaction service will allow for the Company to fill its storage capacity in the NGLNG tank, and volumes needed to fill the Exeter facilities will be trucked.

Northeast Energy Center, LLC (Northeast Energy)

The Company has entered into a Precedent Agreement for up to 1,780 Dth per day and 380,920 Dth per refill season for a term of 15 years for liquefaction services. The Northeast Energy project will be located in central Massachusetts and has an expected in-service date of April 1, 2019. The Northeast Energy Project will connect to the Tennessee Pipeline, allowing the Company to use its existing Tennessee Pipeline capacity to transport volumes from the Zone 4-producing region to the proposed

liquefaction facility located in Zone 6 during off-peak periods. The LNG with be trucked from the facility to the Company's LNG facilities in Rhode Island.

Q. Please provide an update on the Tennessee Gas Pipeline, LLC Northeast Energy Direct Project (NED).

A. The Company participated in Kinder Morgan's Northeast Energy Direct (NED) project, which was intended to move gas from Wright, NY to Dracut, MA and further to various existing citygate delivery points in New England. On April 20, 2016, Kinder Morgan announced that due to insufficient commitments from customers, it would no longer pursue NED and provided the Company notice of termination for each of the executed precedent agreements.

Q. What are the Company's plans to replace the NED Project?

A. The Company is currently working, along with other New England LDCs, to identify and evaluate alternatives to the NED Project for services beginning November 2018. The LDC group is considering both pipeline and imported LNG solutions that deliver to Dracut, MA. Discussions have been held to date with ENGIE, Portland Natural Gas Transmission, Repsol and Spectra Energy. In addition, the Company is working with the Tennessee Pipeline in order to determine facilities needed to deliver incremental volumes to the Company's citygates.

Q. What transportation paths will be available for assignment to marketers?

A. Attachment EDA-4, page 1, shows the paths and corresponding quantities available for assignment to marketers. In total, the Company has made available 35,258 Dth per day of capacity on seven different pipeline paths, increasing the total volume available from last year by 2,500 Dth per day. The Columbia (Maumee/Downington) path has increased by 1,500 Dth per day, from 1,500 Dth per day to a total of 3,000 Dth per day. The additional 1,500 Dth per day is available on a new pipeline path. The Company has included a Tennessee Pipeline path which originates at Dracut, Massachusetts, and delivers to the Company's Cranston citygate. This path provides an additional capacity path option to marketers and also makes available incremental capacity should the marketer program grow throughout the 2016-17 GCR year.

Q. Please explain the surcharge/credit calculation for each assigned pipeline path?

A. The first step in calculating the adjustment charge for each path starts with calculating the system-average cost. The derivation of the weighted-average pipeline path cost of $0.3119 per Dth is shown on Attachment EDA-4, Page 11. This cost is equal to the sum of the 100% 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% load factor per-unit cost. The 100% load factor fixed-cost unit value is $0.6873 per Dth. The system-average pipeline unit variable cost is -$0.3784 per

Dth. The sum of these components results in a weighted average pipeline cost of $0.3089 per Dth. The 100% load factor per-unit cost of $0.0030 for the marketer reconciliation adjustment is then added to get the total weighted-average pipeline cost of $0.3119 per Dth.

Q. How are the delivered costs for each path released to marketers developed in 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 Pipeline Zone 1, shown on Attachment EDA-4, page 6) is comprised of a single contract originating in Zone 1 and terminating in Zone 6. Total fixed costs of $2,441,869 and total variable costs of $12,085,593 are shown in the far right column on page 6 of Attachment EDA-4. Commodity gas costs of $11,027,724 are subtracted from the total variable costs to arrive at the non-gas variable costs, which include pipeline variable charges and any basis differential associated with the path. The cost of the path equals the sum of the fixed unit cost of $0.7042 per Dth at 100% load factor, plus the non-gas variable unit cost of $0.3051 per Dth, for a total path cost of $1.0093 per Dth. The unit cost of $1.0093 per Dth represents the direct costs incurred by the marketer, which are paid directly to the pipeline by the marketer. Since this cost is $0.6974 per Dth greater than the system-average, marketers electing this path would be credited $0.6974 per Dth

per day on their monthly invoice from the Company. A summary of the individual path costs and associated credits or surcharges, for which approval is sought, is shown on Page 1 of Attachment EDA-4.

Q. Does this conclude your testimony?

A. Yes.

Attachments of
Elizabeth D. Arangio

Attachments of Elizabeth D. Arangio

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

Attachment EDA-1
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Attachment EDA-1

Summary of Projected Gas Costs – **CONFIDENTIAL Information**

SUMMARY OF ESTIMATED GAS COSTS FOR 2016-2017 GCR

07/29/2016 NYMEX

Variable Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	GCR TOTAL
Total Pipeline Supply Costs	$5,755,495	$10,570,555	$13,780,360	$12,327,472	$8,632,674	$5,123,826	$2,818,869	$1,687,581	$1,259,395	$1,071,787	$1,072,398	$2,740,388	$66,840,799
Total Storage Product Costs	$171,714	$2,324,107	$2,523,629	$2,316,638	$2,117,031	$19,872	$0	$0	$0	$0	$0	$0	$9,472,991
Total Storage Delivery Costs	$8,478	$115,453	$121,336	$105,980	$100,521	$1,271	$0	$0	$0	$0	$0	$0	$453,039
Total LNG Costs	[redacted]												$3,082,432
Total All Variable Gas Costs	[redacted]												$79,849,261
Fixed Costs													
Total Pipeline Demands	[redacted]												
Total Storage Facilities	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$4,801,259
Total Storage Delivery	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$437,391	$5,248,692
Total Supplier Demands	[redacted]												
Total All Fixed Costs	$4,885,561	$4,864,451	$4,863,113	$4,861,091	$4,734,946	$4,999,883	$5,000,557	$4,999,883	$5,000,557	$5,000,557	$4,999,883	$5,000,557	$59,211,038
Capacity Release Credits	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$705,450	$8,465,400
NGPMP Credit	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$1,141,667	$13,700,000
Net Fixed Costs	$3,038,444	$3,017,335	$3,015,996	$3,013,974	$2,887,830	$3,152,766	$3,153,440	$3,152,766	$3,153,440	$3,153,440	$3,152,766	$3,153,440	$37,045,639
Total All Gas Costs	[redacted]												$116,894,900

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The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-1
Page 1 of 1

Attachment EDA-2
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Attachment EDA-2

Gas Cost Details – **CONFIDENTIAL Information**

National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5

Natural Gas Supply VS. Requirements

Units: DTH

	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	OCT 2017	TOTAL
Forecast Demand													
RI Sales GCR	2,448,062	4,114,762	4,973,224	4,267,565	3,661,287	2,172,286	1,298,037	773,014	561,664	520,513	552,212	1,334,917	26,677,543
Total Demand	2,448,062	4,114,762	4,973,224	4,267,565	3,661,287	2,172,286	1,298,037	773,014	561,664	520,513	552,212	1,334,917	26,677,543
Storage Injections													
TENN 501	0	0	0	0	0	62,552	60,534	60,534	60,534	60,534	120,111	82,679	507,479
GSS 300170	0	0	0	0	0	54,860	54,860	54,860	54,860	54,860	67,306	57,925	399,534
GSS 300168	0	0	0	0	0	9,243	9,243	9,803	9,243	21,856	21,151	21,856	102,394
GSS 300171	0	0	0	0	0	24,546	30,026	24,546	24,546	26,783	25,919	26,783	183,150
GSSTE 600045	0	0	0	0	0	48,024	48,024	48,024	48,024	48,024	94,452	48,024	382,596
TETCO 400515	0	0	0	0	0	7,363	7,363	7,363	7,363	7,851	8,674	8,963	54,941
TETCO 400221	0	0	0	0	0	154,444	154,444	154,444	154,444	164,472	182,038	188,105	1,152,392
TETCO 400185	0	0	0	0	0	6,759	6,759	6,759	6,759	7,213	7,959	8,224	50,430
GSS 300169	0	0	0	0	0	26,793	29,377	26,793	26,793	29,234	28,291	29,234	196,516
COL FSS 9630	0	0	0	0	0	18,095	40,791	40,791	20,396	40,791	26,514	14,277	201,656
TENN 62918	0	0	0	0	0	10,387	12,463	41,664	6,300	43,053	41,664	43,053	198,584
Total Underground Storage	0	0	0	0	0	423,066	453,886	475,583	419,262	504,672	624,080	529,124	3,429,672
LNG PROVIDENCE	0	0	0	0	0	140,706	151,596	146,706	45,365	1,780	95,706	12,501	594,358
LNG EXETER	0	0	0	0	0	6,000	0	0	6,231	25,815	51,000	15,095	104,142
Total LNG Injection	0	0	0	0	0	146,706	151,596	146,706	51,596	27,596	146,706	27,596	698,500
Total Injections	0	0	0	0	0	569,772	605,482	622,288	470,858	532,267	770,786	556,720	4,128,172

Delivered Firm Sales Supply

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENNESSEE ZONE 0 CXN	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 0	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 1	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 4 CXN	348,000	359,600	359,600	324,800	359,600	348,000	337,510	348,000	359,600	359,600	348,000	359,600	4,211,910
TENNESSEE ZONE 4	408,257	383,572	486,469	422,730	334,963	334,147	0	127,126	50,147	92,263	173,576	242,683	3,055,933
TENNESSEE NIAGARA	0	1,067	10,821	3,677	537	0	0	0	0	0	0	0	16,102
TENNESSEE DRACUT	0	24,711	33,498	89,448	27,000	0	0	0	0	0	0	0	174,657
TETCO ELA	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO ETX	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO STX	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO WLA	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO M2	767,219	793,506	793,506	718,621	795,616	774,868	275,994	323,428	532,461	514,207	347,333	798,168	7,434,926
TETCO M3 DELIVERED	454,205	67,665	153,278	142,575	83,106	611,833	681,903	28,090	0	0	20,725	173,368	2,416,749
COLUMBIA MAUMEE	45,364	886,218	891,708	793,836	762,129	24,849	0	0	0	0	0	0	3,404,104
COLUMBIA BROADRUN	38,778	289,464	307,101	247,912	246,797	19,627	0	0	0	0	0	0	1,149,679
COLUMBIA EAGLE	20,508	37,188	70,791	58,689	23,101	44,447	40,791	40,791	20,396	40,791	26,514	14,277	438,285
COLUMBIA DOWNINGTOWN	15,652	27,334	64,348	49,678	14,675	10,910	0	0	0	0	0	0	182,597
TRANSCO LEIDY	36,802	38,067	38,067	34,418	38,106	11,397	2,232	2,160	2,232	2,232	2,160	30,739	238,612
TETCO - DTI - TETCO SCT	2,650	16,432	16,432	14,842	16,432	0	0	0	0	0	0	0	66,789
TETCO to B&W SCT	59,021	63,091	63,091	57,074	63,189	0	0	0	0	0	0	0	305,464
ALGONQUIN - AIM	151,794	258,550	372,735	337,840	137,578	389,946	397,402	363,429	0	0	242,411	229,114	2,880,801
ANE II - DAWN-TENN	0	30,564	30,634	27,649	0	0	0	0	0	0	0	0	88,847
GAZ METRO LNG Refill	0	0	0	0	0	26,706	27,596	26,706	27,596	27,596	26,706	27,596	190,500
GDF SUEZ LNG Refill	0	0	0	0	0	120,000	124,000	120,000	24,000	0	120,000	0	508,000
PORTABLE LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

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National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
Non LNG Liquid take	2,348,250	3,277,030	3,692,079	3,323,788	2,902,829	2,570,024	1,735,832	1,233,025	964,836	1,009,094	1,160,720	1,847,950	26,065,456
LNG Liquid take	0	0	0	0	0	146,706	151,596	146,706	51,596	27,596	146,706	27,596	698,500
Total take	2,348,250	3,277,030	3,692,079	3,323,788	2,902,829	2,716,730	1,887,428	1,379,730	1,016,431	1,036,690	1,307,426	1,875,546	26,763,956
Storage Withdrawals													
TENN 501	0	121,053	150,937	122,786	106,238	2,000	0	0	0	0	0	0	503,014
GSS 300170	8,135	117,951	107,860	68,981	85,368	0	0	0	0	0	0	0	388,295
GSS 300168	1,389	13,887	33,328	22,130	30,759	0	0	0	0	0	0	0	101,493
GSS 300171	0	33,527	68,291	56,695	20,598	0	0	0	0	0	0	0	179,111
GSSTE 600045	73,990	76,533	76,533	69,197	76,611	0	0	0	0	0	0	0	372,864
TETCO 400515	0	13,455	13,455	13,469	11,852	0	0	0	0	0	0	0	52,231
TETCO 400221	0	286,127	286,127	288,035	253,471	0	0	0	0	0	0	0	1,113,760
TETCO 400185	0	12,521	12,521	12,605	11,092	0	0	0	0	0	0	0	48,740
GSS 300169	0	44,027	54,033	49,360	43,490	0	0	0	0	0	0	0	190,909
COL FSS 9630	0	46,405	71,533	50,496	23,867	3,705	0	0	0	0	0	0	196,006
TENN 62918	727	47,716	8,482	57,619	78,241	4,051	0	0	0	0	0	0	196,836
LNG PROV	11,090	11,460	357,473	123,769	11,460	11,090	11,460	11,090	11,460	11,460	11,090	11,460	594,358
LNG EXETER	4,482	13,071	40,572	8,636	5,410	4,482	4,631	4,482	4,631	4,631	4,482	4,631	104,142
Total Withdrawal Delivered	99,812	837,733	1,281,145	943,777	758,458	25,328	16,091	15,572	16,091	16,091	15,572	16,091	4,041,759
Total Storage withdrawal	84,240	813,202	883,101	811,373	741,589	9,756	0	0	0	0	0	0	3,343,260
Total Peaking withdrawal	15,572	24,531	398,044	132,405	16,869	15,572	16,091	15,572	16,091	16,091	15,572	16,091	698,500
Total Supply	**2,448,062**	**4,114,762**	**4,973,224**	**4,267,565**	**3,661,287**	**2,595,352**	**1,751,923**	**1,248,596**	**980,926**	**1,025,185**	**1,176,292**	**1,864,041**	**30,107,215**
Storage withdrawals at Storage Facilty													
TENN 501	0	122,128	152,277	123,876	107,181	2,018	0	0	0	0	0	0	507,479
GSS 300170	8,370	121,365	110,982	70,978	87,839	0	0	0	0	0	0	0	399,534
GSS 300168	1,401	14,010	33,624	22,327	31,033	0	0	0	0	0	0	0	102,394
GSS 300171	0	34,297	69,861	57,940	21,051	0	0	0	0	0	0	0	183,150
GSSTE 600045	76,013	78,546	78,546	70,945	78,546	0	0	0	0	0	0	0	382,596
TETCO 400515	0	14,160	14,160	14,160	12,461	0	0	0	0	0	0	0	54,941
TETCO 400221	0	297,008	297,008	297,008	261,367	0	0	0	0	0	0	0	1,152,392
TETCO 400185	0	12,998	12,998	12,998	11,438	0	0	0	0	0	0	0	50,430
GSS 300169	0	45,342	55,647	50,783	44,744	0	0	0	0	0	0	0	196,516
COL FSS 9630	0	47,760	73,622	51,918	24,539	3,818	0	0	0	0	0	0	201,656
TENN 62918	733	48,140	8,557	58,130	78,936	4,087	0	0	0	0	0	0	198,584
	86,517	835,754	907,282	831,063	759,135	9,922	0	0	0	0	0	0	3,429,672

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National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
07/29/2016 NYMEX	**$3.076**	**$3.320**	**$3.436**	**$3.418**	**$3.360**	**$3.070**	**$3.036**	**$3.066**	**$3.095**	**$3.104**	**$3.084**	**$3.108**	
TENNESSEE ZONE 0 CONNEXION													
Basis	($0.098)	($0.100)	($0.125)	($0.120)	($0.110)	($0.095)	($0.095)	($0.098)	($0.083)	($0.072)	($0.082)	($0.098)	
Usage to Zn 6	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	
Fuel to Zn 6	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	
Total Delivered	$3.1032	$3.3528	$3.4467	$3.4333	$3.3837	$3.1001	$3.0650	$3.0929	$3.1383	$3.1589	$3.1279	$3.1362	
TENNESSEE ZONE 0													
Basis	($0.098)	($0.100)	($0.125)	($0.120)	($0.110)	($0.095)	($0.095)	($0.098)	($0.083)	($0.072)	($0.082)	($0.098)	
Usage to Zn 6	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	
Fuel to Zn 6	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	
Total Delivered	$3.4069	$3.6565	$3.7504	$3.7370	$3.6874	$3.4038	$3.3687	$3.3966	$3.4420	$3.4626	$3.4316	$3.4399	
TENNESSEE ZONE 1													
Basis	($0.129)	($0.077)	($0.088)	($0.032)	($0.077)	($0.073)	($0.090)	($0.092)	($0.053)	($0.028)	($0.062)	($0.062)	
Usage to Zn 6	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	
Fuel to Zn 6	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	
Total Delivered	$3.3197	$3.6238	$3.7317	$3.7707	$3.6649	$3.3711	$3.3187	$3.3475	$3.4173	$3.4523	$3.3968	$3.4214	
TENNESSEE ZONE 4 CONNEXION													
Basis	($1.000)	($0.870)	($0.750)	($0.705)	($0.745)	($0.772)	($0.838)	($0.875)	($0.885)	($0.946)	($1.040)	($1.012)	
Usage to Zn 6	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	
Fuel to Zn 6	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	$2.1027	$2.4799	$2.7179	$2.7452	$2.6463	$2.3266	$2.2257	$2.2187	$2.2378	$2.1854	$2.0704	$2.1229	
TENNESSEE ZONE 4													
Basis	($1.000)	($0.870)	($0.750)	($0.705)	($0.745)	($0.772)	($0.838)	($0.875)	($0.885)	($0.946)	($1.040)	($1.012)	
Usage to Zn 6	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	
Fuel to Zn 6	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	$2.2075	$2.5847	$2.8227	$2.8500	$2.7511	$2.4314	$2.3305	$2.3235	$2.3426	$2.2902	$2.1752	$2.2277	
TENNESSEE NIAGARA													
Basis	($0.259)	($0.218)	($0.194)	($0.178)	($0.092)	($0.411)	($0.566)	($0.565)	($0.565)	($0.565)	($0.566)	($0.566)	
Tenn usage	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	
Tenn Fuel	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	
Total Delivered	$2.9206	$3.2074	$3.3482	$3.3462	$3.3744	$2.7616	$2.5714	$2.6026	$2.6318	$2.6408	$2.6197	$2.6439	
TENNESSEE DRACUT													
Basis	$0.135	$2.062	$4.455	$4.405	$1.935	$0.118	-$0.508	-$0.565	-$0.343	-$0.505	-$0.615	-$0.325	
Usage	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	
Fuel	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	
Total Delivered	$3.2482	$5.4203	$7.9305	$7.8625	$5.3332	$3.2252	$2.5649	$2.5379	$2.7890	$2.6359	$2.5058	$2.8200	
TETCO ELA													
Basis	($0.100)	($0.095)	($0.075)	($0.070)	($0.078)	($0.060)	($0.065)	($0.076)	($0.059)	($0.047)	($0.070)	($0.068)	
Usage to M3	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	3.98%	4.92%	4.92%	4.92%	4.92%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2298	$3.5181	$3.6624	$3.6486	$3.5786	$3.2656	$3.2245	$3.2445	$3.2930	$3.3151	$3.2698	$3.2972	

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The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-2
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National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO ETX													
Basis	($0.094)	($0.150)	($0.158)	($0.107)	($0.112)	($0.101)	($0.094)	($0.097)	($0.070)	($0.050)	($0.090)	($0.091)	
Usage to M3	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	3.98%	4.92%	4.92%	4.92%	4.92%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2361	$3.4597	$3.5743	$3.6093	$3.5425	$3.2224	$3.1940	$3.2224	$3.2814	$3.3119	$3.2488	$3.2730	
TETCO STX													
Basis	($0.068)	($0.090)	($0.115)	($0.110)	($0.102)	($0.058)	($0.058)	($0.060)	($0.040)	($0.030)	($0.040)	($0.058)	
Usage to M3	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	4.07%	5.16%	5.16%	5.16%	5.16%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2720	$3.5376	$3.6344	$3.6206	$3.5674	$3.2762	$3.2404	$3.2699	$3.3216	$3.3416	$3.3100	$3.3163	
TETCO WLA													
Basis	($0.080)	($0.082)	($0.065)	($0.060)	($0.072)	($0.028)	($0.032)	($0.041)	($0.034)	($0.028)	($0.038)	($0.035)	
Usage to M3	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	4.03%	4.99%	4.99%	4.99%	4.99%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2542	$3.5361	$3.6773	$3.6635	$3.5892	$3.3027	$3.2626	$3.2848	$3.3227	$3.3385	$3.3069	$3.3353	
TETCO M2													
Basis	($1.250)	($1.082)	($0.940)	($0.940)	($0.993)	($0.867)	($0.955)	($0.979)	($0.965)	($1.031)	($1.124)	($1.091)	
Usage on Tetco	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Tetco	2.24%	2.89%	2.89%	2.89%	2.89%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$1.9591	$2.3955	$2.6635	$2.6448	$2.5295	$2.3489	$2.2228	$2.2290	$2.2734	$2.2145	$2.0976	$2.1566	
TETCO M3 DELIVERED													
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
COLUMBIA MAUMEE													
Basis	($0.162)	($0.155)	($0.160)	($0.150)	($0.160)	($0.110)	($0.165)	($0.168)	($0.167)	($0.178)	($0.255)	($0.252)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	

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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
COLUMBIA BROADRUN													
Basis	($0.162)	($0.155)	($0.160)	($0.150)	($0.160)	($0.110)	($0.165)	($0.168)	($0.167)	($0.178)	($0.255)	($0.252)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
COLUMBIA EAGLE													
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.3502	$3.8837	$6.2997	$6.2296	$3.6057	$2.4265	$2.2728	$2.3109	$2.4214	$2.3584	$2.1675	$2.2645	
COLUMBIA DOWNINGTOWN													
Basis	($0.320)	$0.880	$3.690	$3.680	$0.600	($0.295)	($0.450)	($0.500)	($0.393)	($0.485)	($0.695)	($0.580)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.8765	$4.3575	$7.3707	$7.3418	$4.1103	$2.8961	$2.7010	$2.6804	$2.8208	$2.7351	$2.4977	$2.6412	
TRANSCO LEIDY													
Basis	($1.295)	($1.200)	($1.205)	($1.160)	($1.118)	($0.960)	($1.022)	($1.062)	($1.067)	($1.130)	($1.208)	($1.185)	
Usage on Transco	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	
Usage on AGT	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	
Fuel on Transco	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Delivered to Algonquin	$1.7954	$2.1356	$2.2470	$2.2741	$2.2580	$2.1256	$2.0292	$2.0192	$2.0433	$1.9891	$1.8907	$1.9379	
Total Delivered	$2.0437	$2.3830	$2.4954	$2.5227	$2.5066	$2.3775	$2.2801	$2.2699	$2.2943	$2.2395	$2.1401	$2.1878	

REDACTED

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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO to DTI to TETCO SCT													
Basis	($1.250)	($1.082)	($0.940)	($0.940)	($0.993)	($0.867)	($0.955)	($0.979)	($0.965)	($1.031)	($1.124)	($1.091)	
Usage on Dominion	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	
Usage on Tetco	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	
Usage on AGT	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	
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	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Delivered to Tetco	$1.8765	$2.2967	$2.5598	$2.5415	$2.4283	$2.2610	$2.1366	$2.1427	$2.1866	$2.1284	$2.0132	$2.0713	
Delivered to Algonquin	$1.9024	$2.3281	$2.5947	$2.5761	$2.4614	$2.2920	$2.1659	$2.1721	$2.2165	$2.1576	$2.0409	$2.0998	
Total Delivered	$2.1519	$2.5773	$2.8462	$2.8274	$2.7117	$2.5457	$2.4183	$2.4245	$2.4694	$2.4099	$2.2919	$2.3514	
TETCO to B&W SCT													
Basis	($1.250)	($1.082)	($0.940)	($0.940)	($0.993)	($0.867)	($0.955)	($0.979)	($0.965)	($1.031)	($1.124)	($1.091)	
Usage on Tetco	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	
Usage on AGT	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	
Fuel to M3	2.24%	2.89%	2.89%	2.89%	2.89%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.1752	$2.6116	$2.8796	$2.8609	$2.7456	$2.5650	$2.4389	$2.4451	$2.4895	$2.4306	$2.3137	$2.3727	
ALGONQUIN - AIM													
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)	
AGT Usage	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
AGT Fuel	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
DAWN TO TENNESSEE - ANE II													
Basis	$0.280	$0.325	$0.365	$0.380	$0.465	$0.150	($0.009)	($0.011)	($0.012)	($0.006)	($0.005)	($0.007)	
Iroquois usage	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	
Tenn usage	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	
Fuel on Union	0.88%	0.99%	1.14%	1.08%	1.01%	0.86%	0.61%	0.51%	0.49%	0.39%	0.39%	0.73%	
Fuel on TransCanada	0.50%	1.48%	1.15%	1.68%	0.28%	0.52%	0.47%	0.44%	0.84%	1.09%	0.86%	0.89%	
Fuel on Iroquois	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on Tenn	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	
Total Delivered	$3.5144	$3.8505	$4.0042	$4.0199	$3.9895	$3.3756	$3.1694	$3.1937	$3.2344	$3.2544	$3.2276	$3.2621	

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Natural Gas Supply VS. Requirements

Units: DTH

Total Delivered to the City Gate Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TENNESSEE ZONE 0 CONNEXION													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.103	$3.353	$3.447	$3.433	$3.384	$3.100	$3.065	$3.093	$3.138	$3.159	$3.128	$3.136	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 0													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.407	$3.656	$3.750	$3.737	$3.687	$3.404	$3.369	$3.397	$3.442	$3.463	$3.432	$3.440	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 1													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.320	$3.624	$3.732	$3.771	$3.665	$3.371	$3.319	$3.347	$3.417	$3.452	$3.397	$3.421	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 4 CONNEXION													
Delivered MMBtu	348,000	359,600	359,600	324,800	359,600	348,000	337,510	348,000	359,600	359,600	348,000	359,600	
Delivered Price	$2.1027	$2.4799	$2.7179	$2.7452	$2.6463	$2.3266	$2.2257	$2.2187	$2.2378	$2.1854	$2.0704	$2.1229	
Total Delivered Cost	$731,739	$891,773	$977,366	$891,627	$951,616	$809,657	$751,210	$772,102	$804,729	$785,870	$720,507	$763,384	
TENNESSEE ZONE 4													
Delivered MMBtu	408,257	383,572	486,469	422,730	334,963	334,147	0	127,126	50,147	92,263	173,576	242,683	
Delivered Price	$2.2075	$2.5847	$2.8227	$2.8500	$2.7511	$2.4314	$2.3305	$2.3235	$2.3426	$2.2902	$2.1752	$2.2277	
Total Delivered Cost	$901,226	$991,420	$1,373,170	$1,204,761	$921,523	$812,446	$0	$295,375	$117,476	$211,301	$377,567	$540,618	
TENNESSEE NIAGARA													
Delivered MMBtu	0	1,067	10,821	3,677	537	0	0	0	0	0	0	0	
Delivered Price	$2.9206	$3.2074	$3.3482	$3.3462	$3.3744	$2.7616	$2.5714	$2.6026	$2.6318	$2.6408	$2.6197	$2.6439	
Total Delivered Cost	$0	$3,422	$36,232	$12,304	$1,812	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE DRACUT													
Delivered MMBtu	0	24,711	33,498	89,448	27,000	0	0	0	0	0	0	0	
Delivered Price	$3.25	$5.42	$7.93	$7.86	$5.33	$3.23	$2.56	$2.54	$2.79	$2.64	$2.51	$2.82	
Total Delivered Cost	$0	$133,940	$265,657	$703,285	$143,998	$0	$0	$0	$0	$0	$0	$0	
TETCO ELA													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.2298	$3.5181	$3.6624	$3.6486	$3.5786	$3.2656	$3.2245	$3.2445	$3.2930	$3.3151	$3.2698	$3.2972	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO ETX													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.2361	$3.4597	$3.5743	$3.6093	$3.5425	$3.2224	$3.1940	$3.2224	$3.2814	$3.3119	$3.2488	$3.2730	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

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	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO STX													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.272	$3.538	$3.634	$3.621	$3.567	$3.276	$3.240	$3.270	$3.322	$3.342	$3.310	$3.316	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO WLA													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.2542	$3.5361	$3.6773	$3.6635	$3.5892	$3.3027	$3.2626	$3.2848	$3.3227	$3.3385	$3.3069	$3.3353	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO M2													
Delivered MMBtu	767,219	793,506	793,506	718,621	795,616	774,868	275,994	323,428	532,461	514,207	347,333	798,168	
Delivered Price	$1.9591	$2.3955	$2.6635	$2.6448	$2.5295	$2.3489	$2.2228	$2.2290	$2.2734	$2.2145	$2.0976	$2.1566	
Total Delivered Cost	$1,503,029	$1,900,870	$2,113,537	$1,900,643	$2,012,543	$1,820,094	$613,465	$720,907	$1,210,509	$1,138,701	$728,576	$1,721,305	
TETCO M3 DELIVERED													
Delivered MMBtu	454,205	67,665	153,278	142,575	83,106	611,833	681,903	28,090	0	0	20,725	173,368	
Delivered Price	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
Total Delivered Cost	$1,037,006	$256,142	$942,968	$867,342	$291,954	$1,442,660	$1,505,167	$63,054	$0	$0	$43,609	$381,274	
COLUMBIA MAUMEE													
Delivered MMBtu	45,364	886,218	891,708	793,836	762,129	24,849	0	0	0	0	0	0	
Delivered Price	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
Total Delivered Cost	$137,886	$2,917,078	$3,037,077	$2,697,196	$2,536,098	$76,710	$0	$0	$0	$0	$0	$0	
COLUMBIA BROADRUN													
Delivered MMBtu	38,778	289,464	307,101	247,912	246,797	19,627	0	0	0	0	0	0	
Delivered Price	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
Total Delivered Cost	$117,866	$952,800	$1,045,958	$842,324	$821,255	$60,590	$0	$0	$0	$0	$0	$0	
COLUMBIA EAGLE													
Delivered MMBtu	20,508	37,188	70,791	58,689	23,101	44,447	40,791	40,791	20,396	40,791	26,514	14,277	
Delivered Price	$2.3502	$3.8837	$6.2997	$6.2296	$3.6057	$2.4265	$2.2728	$2.3109	$2.4214	$2.3584	$2.1675	$2.2645	
Total Delivered Cost	$48,197	$144,429	$445,961	$365,611	$83,294	$107,851	$92,709	$94,267	$49,386	$96,203	$57,470	$32,330	
COLUMBIA DOWNINGTOWN													
Delivered MMBtu	15,652	27,334	64,348	49,678	14,675	10,910	0	0	0	0	0	0	
Delivered Price	$2.8765	$4.3575	$7.3707	$7.3418	$4.1103	$2.8961	$2.7010	$2.6804	$2.8208	$2.7351	$2.4977	$2.6412	
Total Delivered Cost	$45,023	$119,108	$474,284	$364,729	$60,319	$31,596	$0	$0	$0	$0	$0	$0	

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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TRANSCO LEIDY													
Delivered MMBtu	36,802	38,067	38,067	34,418	38,106	11,397	2,232	2,160	2,232	2,232	2,160	30,739	
Delivered Price	$2.0437	$2.3830	$2.4954	$2.5227	$2.5066	$2.3775	$2.2801	$2.2699	$2.2943	$2.2395	$2.1401	$2.1878	
Total Delivered Cost	$75,213	$90,716	$94,993	$86,828	$95,514	$27,096	$5,089	$4,903	$5,121	$4,999	$4,623	$67,250	
TETCO -> DTI -> TETCO SCT													
Delivered MMBtu	2,650	16,432	16,432	14,842	16,432	0	0	0	0	0	0	0	
Delivered Price	$2.1519	$2.5773	$2.8462	$2.8274	$2.7117	$2.5457	$2.4183	$2.4245	$2.4694	$2.4099	$2.2919	$2.3514	
Total Delivered Cost	$5,703	$42,350	$46,769	$41,964	$44,560	$0	$0	$0	$0	$0	$0	$0	
TETCO to B&W SCT													
Delivered MMBtu	59,021	63,091	63,091	57,074	63,189	0	0	0	0	0	0	0	
Delivered Price	$2.1752	$2.6116	$2.8796	$2.8609	$2.7456	$2.5650	$2.4389	$2.4451	$2.4895	$2.4306	$2.3137	$2.3727	
Total Delivered Cost	$128,379	$164,770	$181,679	$163,284	$173,493	$0	$0	$0	$0	$0	$0	$0	
ALGONQUIN - AIM													
Delivered MMBtu	151,794	258,550	372,735	337,840	137,578	389,946	397,402	363,429	0	0	242,411	229,114	
Delivered Price	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
Total Delivered Cost	$346,565	$978,722	$2,293,072	$2,055,223	$483,319	$919,465	$877,187	$815,792	$0	$0	$510,079	$503,872	
DAWN TO TENNESSEE - ANE II													
Delivered MMBtu	0	30,564	30,634	27,649	0	0	0	0	0	0	0	0	
Delivered Price	$3.5144	$3.8505	$4.0042	$4.0199	$3.9895	$3.3756	$3.1694	$3.1937	$3.2344	$3.2544	$3.2276	$3.2621	
Total Delivered Cost	$0	$117,686	$122,667	$111,145	$0	$0	$0	$0	$0	$0	$0	$0	

	NOV 2016	**DEC** 2016	**JAN** 2017	**FEB** 2017	**MAR** 2017	**APR** 2017	**MAY** 2017	**JUN** 2017	**JUL** 2017	**AUG** 2017	**SEP** 2017	**OCT** 2017	**TOTAL**
Financial Hedges as of July 29, 2016													
Quantity	1,850,000	2,570,000	2,870,000	2,600,000	2,120,000	1,152,831	1,022,850	552,866	392,993	369,909	379,114	677,986	16,558,548
Average Price	$3.386	$3.567	$3.507	$3.384	$3.308	$3.088	$3.016	$3.045	$3.153	$2.978	$2.934	$2.929	
07/29/2016 NYMEX	$3.076	$3.320	$3.436	$3.418	$3.360	$3.070	$3.036	$3.066	$3.095	$3.104	$3.084	$3.108	
NYMEX Hedges	$574,038	$634,142	$203,394	-$89,246	-$110,508	$21,160	-$20,612	-$11,807	$22,615	-$46,474	-$56,821	-$121,452	$998,430
Basis Hedges	$103,625	$231,185	$125,575	$108,450	$121,885	$0	$0	$0	$0	$0	$0	$0	$690,720
Impact of Financial Hedges	**$677,663**	**$865,327**	**$328,969**	**$19,204**	**$11,377**	**$21,160**	**-$20,612**	**-$11,807**	**$22,615**	**-$46,474**	**-$56,821**	**-$121,452**	**$1,689,150**
Total Pipeline Costs (Incl Inj)	**$5,755,495**	**$10,570,555**	**$13,780,360**	**$12,327,472**	**$8,632,674**	**$6,129,325**	**$3,824,215**	**$2,754,593**	**$2,209,836**	**$2,190,601**	**$2,385,610**	**$3,888,581**	**$74,449,316**
Total Delivered Pipeline Vol	**2,348,250**	**3,277,030**	**3,692,079**	**3,323,788**	**2,902,829**	**2,570,024**	**1,735,832**	**1,233,025**	**964,836**	**1,009,094**	**1,160,720**	**1,847,950**	**26,065,456**
WACOG (Cost/Volume)	$2.451	$3.226	$3.732	$3.709	$2.974	$2.385	$2.203	$2.234	$2.290	$2.171	$2.055	$2.104	$2.856
Injections	0	0	0	0	0	423,066	453,886	475,583	419,262	504,672	624,080	529,124	3,429,672
Cost of Injections	$0	$0	$0	$0	$0	$1,005,499	$1,005,347	$1,067,011	$950,441	$1,118,813	$1,313,213	$1,148,193	**$7,608,517**
Total GCR Cost Including Financial Hedges, Excluding Injections													
Total Pipeline Costs	**$5,755,495**	**$10,570,555**	**$13,780,360**	**$12,327,472**	**$8,632,674**	**$5,123,826**	**$2,818,869**	**$1,687,581**	**$1,259,395**	**$1,071,787**	**$1,072,398**	**$2,740,388**	**$66,840,799**
Total Pipeline Purchase Volumes	**2,348,250**	**3,277,030**	**3,692,079**	**3,323,788**	**2,902,829**	**2,146,958**	**1,281,946**	**757,442**	**545,573**	**504,422**	**536,640**	**1,318,826**	**22,635,784**

REDACTED

2016 GCR estimate
FIXED COST ESTIMATES
Nov 2016 - Oct 2017

2016-2017 Gas Supply Fixed Costs
UNIT PRICES

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
PIPELINE FIXED COST UNIT PRICES $/Dth													
ALGONQUIN AFT-E/AFT-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	$6.5734
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.6294	$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	[redacted]											
COLUMBIA FTS DEMAND	$/Dth	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900
DOMINION FTNN DEMAND	$/Dth	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619
IROQUOIS DEMAND	$/Dth	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971
NATIONAL FUEL DEMAND	$/Dth	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$/Dth	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563
TENNESSEE FT-A DEMAND DRACUT	$/Dth	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551
TEXAS EASTERN CDS STX DEMAND M3	$/Dth	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040
TEXAS EASTERN CDS WLA DEMAND M3	$/Dth	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250
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	$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	$2.1890
TEXAS EASTERN CDS 1-3 DEMAND M3	$/Dth	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840
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	$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	$2.7220
TEXAS EASTERN SCT WLA DEMAND M3	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
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	$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	$0.8760
TEXAS EASTERN SCT 1-3 DEMAND M3	$/Dth	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730
TEXAS EASTERN SCT STX DEMAND M2	$/Dth	$2.7220	$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 M2	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
TEXAS EASTERN SCT ELA DEMAND M2	$/Dth	$0.9500	$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 M2	$/Dth	$0.8760	$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 1-2 DEMAND M2	$/Dth	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630
TRANSCANADA DEMAND	$/Dth	$12.8475	$13.2758	$13.2758	$11.9910	$13.2758	$12.8475	$13.2758	$12.8475	$13.2758	$13.2758	$12.8475	$13.2758
TRANSCO DEMAND ZONE 6 TO 6	$/Dth	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306
UNION DEMAND	$/Dth	$2.3040	$2.3808	$2.3808	$2.1504	$2.3808	$2.3040	$2.3808	$2.3040	$2.3808	$2.3808	$2.3040	$2.3808
STORAGE FIXED COST UNIT PRICES													
COLUMBIA FSS DEMAND	$/Dth	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010
COLUMBIA FSS CAPACITY	$/Dth	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288
DOMINION GSS DEMAND	$/Dth	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618
DOMINION GSS CAPACITY	$/Dth	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145
DOMINION GSS-TE DEMAND	$/Dth	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618	$1.8618
DOMINION GSS-TE CAPACITY	$/Dth	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145
TENNESSEE FSMA DEMAND	$/Dth	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938
TENNESSEE FSMA CAPACITY	$/Dth	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205
TEXAS EASTERN SS-1 DEMAND	$/Dth	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430	$5.4430
TEXAS EASTERN SS-1 CAPACITY	$/Dth	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293
TEXAS EASTERN FSS-1 DEMAND	$/Dth	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960	$0.8960
TEXAS EASTERN FSS-1 CAPACITY	$/Dth	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293

REDACTED

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-2
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STORAGE DELIVERY FIXED		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
UNIT RATES ($/Dth)													
PATH													
ALGONQUIN FOR TETCO SS-1	$/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
ALGONQUIN DELIVERY FOR FSS-1	$/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
ALGONQUIN SCT FOR SS-1	$/Dth	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$/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
ALGONQUIN SCT DELIVERY FOR GSS-TE	$/Dth	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294
ALGONQUIN DELIVERY FOR GSS	$/Dth	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854
ALGONQUIN DELIVERY FOR FSS	$/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
COLUMBIA DELIVERY FOR FSS	$/Dth	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200	$6.0200
DOMINION DELIVERY FOR GSS	$/Dth	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619
DOMINION DELIVERY FOR GSS	$/Dth	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619
TENNESSEE DELIVERY FOR GSS	$/Dth	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463
TENNESSEE DELIVERY FOR FSMA	$/Dth	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463	$8.1463
TETCO DELIVERY FOR FSS-1	$/Dth	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850	$5.1850
TETCO DELIVERY FOR GSS/GSS-TE	$/Dth	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640
TETCO DELIVERY FOR GSS	$/Dth	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790
SUPPLIER FIXED COST UNIT PRICES													
GAZ METRO DEMAND PAYMENT Summer	$/Dth												
ENGIE GAS DEMAND PAYMENT Summer	$/Dth												
ENGIE GAS DEMAND PAYMENT Winter	$/Dth												
PEAKING SUPPLY AT DRACUT	$/Dth												
SUPPLY CALL AT TETCO M3	$/Dth												
							BILLING UNITS						
PIPELINE FIXED COST BILLING UNITS													
ALGONQUIN AFT-E/AFT-1 DEMAND	Dth	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285
ALGONQUIN AFT-3 DEMAND	Dth	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	Dth	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079
ALGONQUIN AIM DEMAND	Dth	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
COLUMBIA FTS DEMAND	Dth	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
DOMINION FTNN DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
IROQUOIS DEMAND	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NATIONAL FUEL DEMAND	Dth	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	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
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	Dth	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
TENNESSEE FT-A DEMAND DRACUT	Dth	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500
TENNESSEE FT-A DEMAND DRACUT FOR PEAKII	Dth	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500
TENNESSEE FT-A DEMAND ZONE 5 TO 6	Dth	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067
TEXAS EASTERN CDS STX DEMAND M3	Dth	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN CDS WLA DEMAND M3	Dth	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN CDS ELA DEMAND M3	Dth	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN CDS ETX DEMAND M3	Dth	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TEXAS EASTERN CDS 1-3 DEMAND M3	Dth	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TEXAS EASTERN FTS DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
TEXAS EASTERN SCT STX DEMAND M3	Dth	571	571	571	571	571	571	571	571	571	571	571	571
TEXAS EASTERN SCT WLA DEMAND M3	Dth	648	648	648	648	648	648	648	648	648	648	648	648
TEXAS EASTERN SCT ELA DEMAND M3	Dth	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TEXAS EASTERN SCT ETX DEMAND M3	Dth	329	329	329	329	329	329	329	329	329	329	329	329
TEXAS EASTERN SCT 1-3 DEMAND M3	Dth	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TEXAS EASTERN SCT STX DEMAND M2	Dth	401	401	401	401	401	401	401	401	401	401	401	401
TEXAS EASTERN SCT WLA DEMAND M2	Dth	455	455	455	455	455	455	455	455	455	455	455	455
TEXAS EASTERN SCT ELA DEMAND M2	Dth	831	831	831	831	831	831	831	831	831	831	831	831
TEXAS EASTERN SCT ETX DEMAND M2	Dth	231	231	231	231	231	231	231	231	231	231	231	231
TEXAS EASTERN SCT 1-2 DEMAND M2	Dth	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474
TRANSCANADA DEMAND	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
TRANSCO DEMAND ZONE 6 TO 6	Dth	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
UNION DEMAND	Dth	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025

REDACTED

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
STORAGE FIXED COST BILLING UNITS													
COLUMBIA FSS DEMAND	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA FSS CAPACITY	Dth	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957
DOMINION GSS DEMAND	Dth	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403
DOMINION GSS CAPACITY	Dth	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304
DOMINION GSS-TE DEMAND	Dth	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337
DOMINION GSS-TE CAPACITY	Dth	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324
TENNESSEE FSMA DEMAND	Dth	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169
TENNESSEE FSMA CAPACITY	Dth	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343
TEXAS EASTERN SS-1 DEMAND	Dth	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802
TEXAS EASTERN SS-1 CAPACITY	Dth	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336
TEXAS EASTERN FSS-1 DEMAND	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TEXAS EASTERN FSS-1 CAPACITY	Dth	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720
STORAGE DELIVERY BILLING UNITS (DTH)													
ALGONQUIN FOR TETCO SS-1	Dth	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137
ALGONQUIN DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
ALGONQUIN SCT FOR SS-1	Dth	665	665	665	665	665	665	665	665	665	665	665	665
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	Dth	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739
ALGONQUIN SCT DELIVERY FOR GSS-TE	Dth	187	187	187	187	187	187	187	187	187	187	187	187
ALGONQUIN DELIVERY FOR GSS	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
ALGONQUIN DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
DOMINION DELIVERY FOR GSS	Dth	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324
DOMINION DELIVERY FOR GSS	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
TENNESSEE DELIVERY FOR GSS	Dth	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725
TENNESSEE DELIVERY FOR FSMA	Dth	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111
TETCO DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TETCO DELIVERY FOR GSS/GSS-TE	Dth	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377
TETCO DELIVERY FOR GSS-TE	Dth	538	538	538	538	538	538	538	538	538	538	538	538
TETCO DELIVERY FOR GSS-TE	Dth	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011
TETCO DELIVERY FOR GSS	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
SUPPLIER FIXED COST BILLING UNITS													
GAZ METRO DEMAND PAYMENT Summer	Dth	[redacted]											
ENGIE GAS DEMAND PAYMENT Summer	Dth												
ENGIE GAS DEMAND PAYMENT Winter	Dth												
PEAKING SUPPLY AT DRACUT	Dth												
SUPPLY CALL AT TETCO M3	Dth												

REDACTED

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	
							TOTAL COST							
PIPELINE FIXED COST DOLLARS														
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	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
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	$10,725	
ALGONQUIN AIM DEMAND	$	[redacted]												
CANADIAN CAPACITY AMA FEE	$													
COLUMBIA FTS DEMAND	$	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	
DOMINION FTNN DEMAND	$	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	
IROQUOIS DEMAND	$	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	
NATIONAL FUEL DEMAND	$	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	
TENNESSEE FT-A DEMAND DRACUT	$	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	$49,807	
TENNESSEE FT-A DEMAND DRACUT FOR PEAKII	$	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	
TEXAS EASTERN CDS STX DEMAND M3	$	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	
TEXAS EASTERN CDS WLA DEMAND M3	$	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	
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 1-3 DEMAND M3	$	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	
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	$	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	
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	$	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	
TEXAS EASTERN SCT STX DEMAND M2	$	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	
TEXAS EASTERN SCT WLA DEMAND M2	$	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	
TEXAS EASTERN SCT ELA DEMAND M2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TEXAS EASTERN SCT ETX DEMAND M2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TEXAS EASTERN SCT 1-2 DEMAND M2	$	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	
TRANSCANADA DEMAND	$	$13,002	$13,435	$13,435	$12,135	$13,435	$13,002	$13,435	$13,002	$13,435	$13,435	$13,002	$13,435	
TRANSCO DEMAND ZONE 6 TO 6	$	$4,859	$5,021	$5,021	$4,535	$5,021	$4,859	$5,021	$4,859	$5,021	$5,021	$4,859	$5,021	
UNION DEMAND	$	$2,362	$2,440	$2,440	$2,204	$2,440	$2,362	$2,440	$2,362	$2,440	$2,440	$2,362	$2,440	
WESTERLY LATERAL (Yankee Gas)	$	[redacted]												
TOTAL PIPELINE DEMAND COSTS														
STORAGE FIXED COST DOLLARS														
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	$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	$5,874	
DOMINION GSS DEMAND	$	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	
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	$15,070	
DOMINION GSS-TE DEMAND	$	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	
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	$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	$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	$16,715	
TEXAS EASTERN SS-1 DEMAND	$	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	
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	$13,361	
TEXAS EASTERN FSS-1 DEMAND	$	$846	$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	$610	
NATIONAL GRID LNG 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	$163,740	**$1,964,880**
TOTAL STORAGE DEMAND COSTS	$	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$4,801,259**

REDACTED

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-2
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STORAGE DELIVERY FIXED COSTS														
ALGONQUIN FOR TETCO SS-1	$	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	
ALGONQUIN DELIVERY FOR FSS-1	$	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	
ALGONQUIN SCT FOR SS-1	$	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	
ALGONQUIN SCT DELIVERY FOR GSS-TE	$	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	
ALGONQUIN DELIVERY FOR GSS CONV	$	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	
ALGONQUIN DELIVERY FOR FSS	$	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	
COLUMBIA DELIVERY FOR FSS	$	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	
DOMINION DELIVERY FOR GSS	$	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	
DOMINION DELIVERY FOR GSS CONV	$	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	
TENNESSEE DELIVERY FOR GSS	$	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	
TENNESSEE DELIVERY FOR FSMA	$	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	
TETCO DELIVERY FOR FSS-1	$	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	
TETCO DELIVERY FOR GSS/GSS-TE	$	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	
TETCO DELIVERY FOR GSS-TE	$	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	
TETCO DELIVERY FOR GSS-TE	$	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	
TETCO DELIVERY FOR GSS CONV	$	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	
TOTAL STORAGE DELIVERY DEMAND COSTS		**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$5,248,692**
GAZ METRO DEMAND PAYMENT Summer	$													
ENGIE GAS DEMAND PAYMENT Summer	$													
ENGIE GAS DEMAND PAYMENT Winter	$													
PEAKING SUPPLY AT DRACUT	$													
SUPPLY CALL AT TETCO M3	$													
TOTAL SUPPLIER DEMAND COSTS														
TOTAL ALL DEMAND COSTS	$	**$4,885,561**	**$4,864,451**	**$4,863,113**	**$4,861,091**	**$4,734,946**	**$4,999,883**	**$5,000,557**	**$4,999,883**	**$5,000,557**	**$5,000,557**	**$4,999,883**	**$5,000,557**	**$59,211,038**
		Nov-16	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Total**
Marketer Demand Charge Credits														
Capacity Release Volumes as of August 1, 2016														
Tennessee	Dth	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	
Algonquin	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	
Tetco STX/AGT	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	
Tetco WLA/AGT	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	
Tetco ELA/AGT	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	
Columbia/AGT	Dth	2,489	2,489	2,489	2,489	2,489	2,489	2,489	2,489	2,489	2,489	2,489	2,489	
Total		**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	**33,746**	
System Weighted Average cost per MMBtu		**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	**$20.9047**	
Total Demand Charge Credit		**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$8,465,400**
Demand Costs Net of Releases to Marketers	$	**$4,180,111**	**$4,159,001**	**$4,157,663**	**$4,155,641**	**$4,029,496**	**$4,294,433**	**$4,295,107**	**$4,294,433**	**$4,295,107**	**$4,295,107**	**$4,294,433**	**$4,295,107**	**$50,745,639**
TOTAL PIPELINE DEMANDS	$													
TOTAL STORAGE FACILITIES DEMANDS	$	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$400,105**	**$4,801,259**
TOTAL STORAGE DELIVERY DEMANDS	$	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$437,391**	**$5,248,692**
TOTAL SUPPLIER DEMANDS	$													
Total All Demands	$	**$4,885,561**	**$4,864,451**	**$4,863,113**	**$4,861,091**	**$4,734,946**	**$4,999,883**	**$5,000,557**	**$4,999,883**	**$5,000,557**	**$5,000,557**	**$4,999,883**	**$5,000,557**	**$59,211,038**
Marketer Release Credits	$	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$705,450**	**$8,465,400**
NGPMP Credit		**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$1,141,667**	**$13,700,000**
Demand Net of Releases	$	**$3,038,444**	**$3,017,335**	**$3,015,996**	**$3,013,974**	**$2,887,830**	**$3,152,766**	**$3,153,440**	**$3,152,766**	**$3,153,440**	**$3,153,440**	**$3,152,766**	**$3,153,440**	**$37,045,639**

REDACTED

Storage Product Cost

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
WACOG INJECTIONS	$2.162	$2.962	$3.643	$3.703	$2.970	$2.377	$2.215	$2.244	$2.267	$2.217	$2.104	$2.170	
Injection cost	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	
Total injection cost	$2.188	$2.987	$3.668	$3.728	$2.995	$2.402	$2.240	$2.269	$2.292	$2.242	$2.129	$2.195	

COMBINED STORAGE	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	
Beginning Inv Vol	4,707,804	4,621,287	3,785,534	2,878,252	2,047,189	1,288,054	1,701,198	2,155,084	2,630,666	3,049,929	3,554,600	4,178,680	
Vol Withdrawn	86,517	835,754	907,282	831,063	759,135	9,922	0	0	0	0	0	0	3,429,672
Vol Injected	0	0	0	0	0	423,066	453,886	475,583	419,262	504,672	624,080	529,124	3,429,672
Begining Inv $ (virtual)	$9,596,388	$9,420,032	$7,716,432	$5,867,029	$4,172,991	$2,625,570	$3,621,498	$4,638,275	$5,717,263	$6,678,263	$7,809,786	$9,138,715	
$ Withdrawn (1)	$176,356	$2,370,076	$2,572,920	$2,356,774	$2,152,797	$20,225	$0	$0	$0	$0	$0	$0	$9,649,149
$ Injected	$0	$0	$0	$0	$0	$1,016,153	$1,016,777	$1,078,988	$961,000	$1,131,523	$1,328,929	$1,161,519	$7,694,889
Ending Vol	4,621,287	3,785,534	2,878,252	2,047,189	1,288,054	1,701,198	2,155,084	2,630,666	3,049,929	3,554,600	4,178,680	4,707,804	
Ending $	$9,420,032	$7,716,432	$5,867,029	$4,172,991	$2,625,570	$3,621,498	$4,638,275	$5,717,263	$6,678,263	$7,809,786	$9,138,715	$10,300,233	
Avg $/Mmbtu	$2.0384	$2.0384	$2.0384	$2.0384	$2.0384	$2.1288	$2.1522	$2.1733	$2.1896	$2.1971	$2.1870	$2.1879	
Withdrawal cost	**$1,520**	**$24,821**	**$25,956**	**$24,657**	**$21,993**	**$112**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$99,058**
Transportation cost	**$2,317**	**$44,662**	**$46,089**	**$41,187**	**$42,762**	**$806**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$177,823**
Costs allocated to fuel	**$4,641**	**$45,970**	**$49,291**	**$40,136**	**$35,766**	**$354**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$176,158**
Storage value Less fuel	**$171,714**	**$2,324,107**	**$2,523,629**	**$2,316,638**	**$2,117,031**	**$19,872**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$9,472,991**
Delivered Volumes	84,240	813,202	883,101	811,373	741,589	9,756	0	0	0	0	0	0	3,343,260
Hedge Amortization	$68,993	$666,477	$723,517	$662,736	$605,377	$7,913	$0	$0	$0	$0	$0	$0	$2,735,012

- amortization of hedges on injection gas
$2,735,012
(1) Includes Hedge Amortization
3,429,672 Withdrawal

REDACTED

Storage Withdrawal variable costs
2016-2017 GCR Storage estimate

Storage Withdrawals at Facility Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_501	0	122,128	152,277	123,876	107,181	2,018	0	0	0	0	0	0	507,479
GSS 300170	8,370	121,365	110,982	70,978	87,839	0	0	0	0	0	0	0	399,534
GSS 300168	1,401	14,010	33,624	22,327	31,033	0	0	0	0	0	0	0	102,394
GSS 300171	0	34,297	69,861	57,940	21,051	0	0	0	0	0	0	0	183,150
GSS-TE 600045	76,013	78,546	78,546	70,945	78,546	0	0	0	0	0	0	0	382,596
TETCO_400515	0	14,069	14,069	14,069	12,381	0	0	0	0	0	0	0	54,589
TETCO_400221	0	290,563	290,563	290,563	255,696	0	0	0	0	0	0	0	1,127,385
TETCO 400185	0	12,715	12,715	12,715	11,190	0	0	0	0	0	0	0	49,336
GSS 300169	0	45,342	55,647	50,783	44,744	0	0	0	0	0	0	0	196,516
COL FSS 9630	0	47,760	73,622	51,918	24,539	3,818	0	0	0	0	0	0	201,656
TENN_62918	733	48,140	8,557	58,130	78,936	4,087	0	0	0	0	0	0	198,584
TOTAL	86,517	828,936	900,464	824,245	753,135	9,922	0	0	0	0	0	0	3,403,219

STORAGE WITHDRAWAL PRICES													
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	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	$0.0149	
Dominion GSS-TE Withdrawal	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	$0.0180	
Tetco SS-1 Withdrawal	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	$0.0577	
Tetco FSS-1 Withdrawal	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	
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	

Withdrawal Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Withdrawal	$6	$1,481	$1,399	$1,583	$1,619	$53	$0	$0	$0	$0	$0	$0	$6,143
Dominion GSS Withdrawal	$146	$3,204	$4,025	$3,010	$2,752	$0	$0	$0	$0	$0	$0	$0	$13,136
Dominion GSS-TE Withdrawal	$1,368	$1,414	$1,414	$1,277	$1,414	$0	$0	$0	$0	$0	$0	$0	$6,887
Tetco SS-1 Withdrawal	$0	$17,499	$17,499	$17,499	$15,399	$0	$0	$0	$0	$0	$0	$0	$67,897
Tetco FSS-1 Withdrawal	$0	$492	$492	$492	$433	$0	$0	$0	$0	$0	$0	$0	$1,911
Columbia Withdrawal	$0	$731	$1,126	$794	$375	$58	$0	$0	$0	$0	$0	$0	$3,085
Total	$1,520	$24,821	$25,956	$24,657	$21,993	$112	$0	$0	$0	$0	$0	$0	$99,058

Storage Withdrawals at Gate Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_501	0	121,053	150,937	122,786	106,238	2,000	0	0	0	0	0	0	503,014
GSS 300170	8,135	117,951	107,860	68,981	85,368	0	0	0	0	0	0	0	388,295
GSS 300168	1,389	13,887	33,328	22,130	30,759	0	0	0	0	0	0	0	101,493
GSS 300171	0	33,527	68,291	56,695	20,598	0	0	0	0	0	0	0	179,111
GSS-TE 600045	73,990	76,533	76,533	69,197	76,611	0	0	0	0	0	0	0	372,864
TETCO_400515	0	13,455	13,455	13,469	11,852	0	0	0	0	0	0	0	52,231
TETCO_400221	0	286,127	286,127	288,035	253,471	0	0	0	0	0	0	0	1,113,760
TETCO 400185	0	12,521	12,521	12,605	11,092	0	0	0	0	0	0	0	48,740
GSS 300169	0	44,027	54,033	49,360	43,490	0	0	0	0	0	0	0	190,909
COL FSS 9630	0	46,405	71,533	50,496	23,867	3,705	0	0	0	0	0	0	196,006
TENN_62918	727	47,716	8,482	57,619	78,241	4,051	0	0	0	0	0	0	196,836
TOTAL	84,240	813,202	883,101	811,373	741,589	9,756	0	0	0	0	0	0	3,343,260

Storage Transportation Prices													
Tennessee Transportation	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	
Dominion Trans on Tetco/AGT	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	$0.0140	
Dominion Trans on DTI/Tetco/AGT	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	$0.0282	
Dominion Trans on Tennessee	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	
Dominion Trans on DTI/Tennessee	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	$0.1279	
Tetco SS-1 Trans	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Tetco FSS-1 Trans	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	$0.0581	
Columbia Trans	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	$0.0319	

Storage Transportation Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Transportation	$83	$19,189	$18,126	$20,512	$20,975	$688	$0	$0	$0	$0	$0	$0	$79,573
Dominion Trans on Tetco/AGT	$1,036	$1,541	$2,028	$1,762	$1,361	$0	$0	$0	$0	$0	$0	$0	$7,728
Dominion Trans on DTI/Tetco/AGT	$0	$1,242	$1,524	$1,392	$1,226	$0	$0	$0	$0	$0	$0	$0	$5,384
Dominion Trans on Tennseess	$158	$1,579	$3,789	$2,516	$3,497	$0	$0	$0	$0	$0	$0	$0	$11,540
Dominion Trans on DTI/Tennessee	$1,040	$15,086	$13,795	$8,823	$10,919	$0	$0	$0	$0	$0	$0	$0	$49,663
Tetco SS-1 Trans	$0	$3,763	$3,763	$3,788	$3,333	$0	$0	$0	$0	$0	$0	$0	$14,648
Tetco FSS-1 Trans	$0	$782	$782	$783	$689	$0	$0	$0	$0	$0	$0	$0	$3,036
Columbia Trans	$0	$1,480	$2,282	$1,611	$761	$118	$0	$0	$0	$0	$0	$0	$6,253
Total	$2,317	$44,662	$46,089	$41,187	$42,762	$806	$0	$0	$0	$0	$0	$0	$177,823

Total Variable	$3,837	$69,483	$72,045	$65,844	$64,755	$918	$0	$0	$0	$0	$0	$0	$276,881

REDACTED

LNG Estimate for 2016 - 2017

NATIONAL GRID - RI SERVICE AREA
NOVEMBER 2016 - OCTOBER 2017

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
07/29/2016 NYMEX	$3.076	$3.320	$3.436	$3.418	$3.360	$3.070	$3.036	$3.066	$3.095	$3.104	$3.084	$3.108	
Trucking GDF Suez													
Basis Engie Gas Contract													
Delivered Cost Engie Gas													
Trucking Gaz Metro													
Gaz Metro Contract Commodity													
Delivered Cost Gaz Metro													

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
Combined LNG Inv													
Beginning Inventory Volume	782,000	766,428	741,897	343,853	211,448	194,579	325,713	461,218	592,352	627,857	639,362	770,495	
Engie Gas Injections													
Gaz Metro Injections													
Volume Withdrawn	15,572	24,531	398,044	132,405	16,869	15,572	16,091	15,572	16,091	16,091	15,572	16,091	698,500
Begining Inventory													
Injection Costs													
Withdrawal Costs													
Ending Volume	766,428	741,897	343,853	211,448	194,579	325,713	461,218	592,352	627,857	639,362	770,495	782,000	
Ending Inventory													
Average Cost Per Dth													
Portable Vapor													
Portable Vapor Volume	0	0	0	0	0	0	0	0	0	0	0	0	
Average Cost Per Dth													
Total Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total All LNG Costs													

REDACTED

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-2
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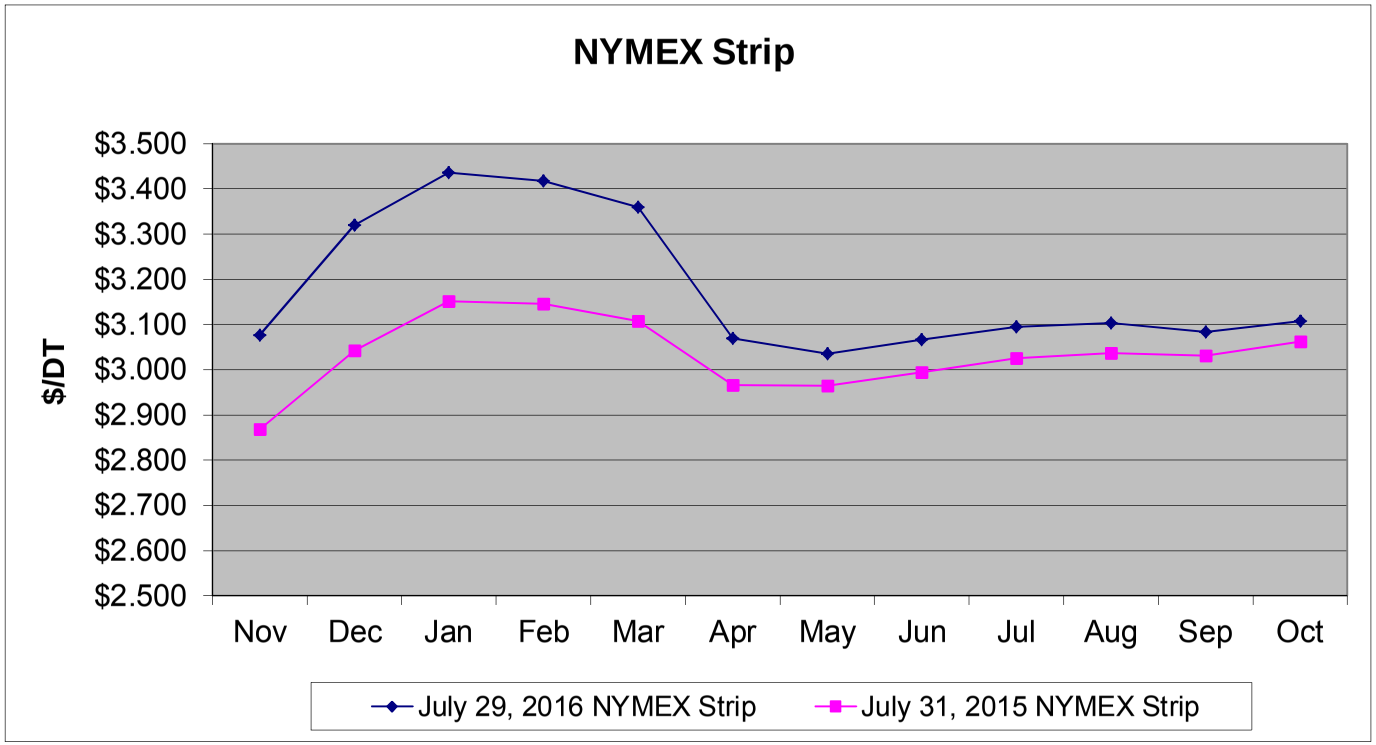
Attachment EDA-3

Attachment EDA-3

NYMEX Strip Comparison

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
July 31, 2015 NYMEX Strip	$2.868	$3.042	$3.152	$3.146	$3.108	$2.966	$2.965	$2.995	$3.026	$3.037	$3.031	$3.062
July 29, 2016 NYMEX Strip	$3.076	$3.320	$3.436	$3.418	$3.360	$3.070	$3.036	$3.066	$3.095	$3.104	$3.084	$3.108



The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-3
Page 1 of 1

Attachment EDA-4
REDACTED

Attachment EDA-4

Assignment of Pipeline Capacity – **CONFIDENTIAL Information**

PRELIMINARY **PRELIMINARY**

12 Month Forward Pricing

National Grid
Summary of Transportation Capacity Release
Pipeline Path Availability and Pricing
November 2016 - October 2017

Path to City Gate	As of 8/1/16 Existing Releases	Total Available	Remaining Available	Cost per Dth	New Credit or Surcharge	Old Credit or Surcharge
Company Weighted Average				**$0.3119**		
Tennessee Zone 1	9,499	9,500	1	$1.0093	($0.6974)	($0.6263)
Tennessee Dracut	0	1,000	1,000	$1.3261	($1.0142)	$0.0000
Algonquin @ Lambertville, NJ	2,714	2,714	0	$0.1524	$0.1595	$0.3719
Texas Eastern - South Texas Algonquin @ Lambertville, NJ	4,044	4,044	0	$1.1810	($0.8691)	($0.8342)
Texas Eastern - West La Algonquin @ Lambertville, NJ	8,500	8,500	0	$0.9687	($0.6568)	($0.5806)
Texas Eastern - East La Algonquin @ Lambertville, NJ	6,500	6,500	0	$0.8476	($0.5357)	($0.4578)
Columbia (Maumee/Downington) at 5:1 ratio*	2,489	3,000	511	$0.4162	($0.1043)	$0.0585
Totals:	33,746	35,258	1,512			

REDACTED

Gas Year 2016 - 2017
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
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	
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	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	
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	
VARIABLE														
TETCO USAGE STX TO M3	$/Dth	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	
ALGONQUIN USAGE	$/Dth	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY AREA BASIS	$/Dth	($0.0680)	($0.0900)	($0.1150)	($0.1100)	($0.1020)	($0.0580)	($0.0580)	($0.0600)	($0.0400)	($0.0300)	($0.0400)	($0.0580)	
NET COST AFTER BASIS	$/Dth	$3.0080	$3.2300	$3.3210	$3.3080	$3.2580	$3.0120	$2.9780	$3.0060	$3.0550	$3.0740	$3.0440	$3.0500	

BILLING UNITS

FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	4,088	4,079	4,079	4,079	4,079	4,088	4,088	4,088	4,088	4,088	4,088	4,088	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	4,088	4,079	4,079	4,079	4,079	4,088	4,088	4,088	4,088	4,088	4,088	4,088	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	4,088	4,079	4,079	4,079	4,079	4,088	4,088	4,088	4,088	4,088	4,088	4,088	
TETCO M1 TO M3 DEMAND	$/Dth	4,088	4,079	4,079	4,079	4,079	4,088	4,088	4,088	4,088	4,088	4,088	4,088	
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	48,528
VARIABLE														
PURCHASE VOLUMES	Dth	127,848	133,345	133,345	120,440	133,345	127,848	132,110	127,848	132,110	132,110	127,848	132,110	1,560,305
TETCO USAGE STX TO M3	Dth	122,645	126,464	126,464	114,226	126,464	122,645	126,733	122,645	126,733	126,733	122,645	126,733	1,491,128
ALGONQUIN USAGE	Dth	121,320	125,364	125,364	113,232	125,364	121,320	125,364	121,320	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	121,320	125,364	125,364	121,320	125,364	1,476,060

FUEL USE %

TETCO STX TO M3 FUEL	%	4.07%	5.16%	5.16%	5.16%	5.16%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	
ALGONQUIN AFT-E FUEL	%	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	

TRANSPORTATION COST

FIXED														
TETCO STX SUPPLY ZONE DEMAND	$	$27,816	$27,757	$27,757	$27,757	$27,757	$27,816	$27,816	$27,816	$27,816	$27,816	$27,816	$27,816	$333,554
TECCO WLA SUPPLY ZONE DEMAND	$	$11,549	$11,525	$11,525	$11,525	$11,525	$11,549	$11,549	$11,549	$11,549	$11,549	$11,549	$11,549	$138,490
TETCO ELA SUPPLY ZONE DEMAND	$	$9,709	$9,689	$9,689	$9,689	$9,689	$9,709	$9,709	$9,709	$9,709	$9,709	$9,709	$9,709	$116,430
TETCO M1 TO M3 DEMAND	$	$43,678	$43,585	$43,585	$43,585	$43,585	$43,678	$43,678	$43,678	$43,678	$43,678	$43,678	$43,678	$523,764
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	$26,583	$318,994
VARIABLE														
TETCO USAGE STX TO M3	$	$10,866	$11,205	$11,205	$10,120	$11,205	$10,866	$11,229	$10,866	$11,229	$11,229	$10,866	$11,229	$132,114
ALGONQUIN USAGE	$	$1,529	$1,580	$1,580	$1,427	$1,580	$1,529	$1,580	$1,529	$1,580	$1,580	$1,529	$1,580	$18,598
PURCHASE COST	$	$384,567	$430,704	$442,838	$398,417	$434,437	$385,078	$393,422	$384,311	$403,595	$406,105	$389,169	$402,934	$4,855,578
TOTAL FIXED	$	$119,335	$119,138	$119,138	$119,138	$119,138	$119,335	$119,335	$119,335	$119,335	$119,335	$119,335	$119,335	$1,431,232
TOTAL VARIABLE	$	$396,962	$443,488	$455,623	$409,964	$447,222	$397,473	$406,230	$396,706	$416,403	$418,913	$401,564	$415,742	$5,006,290
DELIVERED COST AT NYMEX	$	$373,180	$416,208	$430,751	$387,027	$421,223	$372,452	$380,605	$371,967	$388,002	$389,130	$374,151	$389,631	$4,694,328
NET NON-GAS VARIABLE COST	$	$23,781	$27,280	$24,872	$22,937	$25,999	$25,021	$25,625	$24,739	$28,401	$29,783	$27,413	$26,111	$311,962
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1960**	**$0.2176**	**$0.1984**	**$0.2026**	**$0.2074**	**$0.2062**	**$0.2044**	**$0.2039**	**$0.2266**	**$0.2376**	**$0.2260**	**$0.2083**	**$0.2113**
AVERAGE FIXED COST	$/Dth													$29.4929
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.9696**
TOTAL PATH COST	$/Dth													**$1.1810**

REDACTED

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-4
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Gas Year 2016 - 2017
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
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	
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	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	
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	
VARIABLE														
TETCO USAGE WLA TO M3	$/Dth	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	
ALGONQUIN USAGE	$/Dth	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY AREA BASIS	$/Dth	($0.0800)	($0.0820)	($0.0650)	($0.0600)	($0.0720)	($0.0280)	($0.0320)	($0.0410)	($0.0340)	($0.0280)	($0.0380)	($0.0350)	
NET COST AFTER BASIS	$/Dth	$2.9960	$3.2380	$3.3710	$3.3580	$3.2880	$3.0420	$3.0040	$3.0250	$3.0610	$3.0760	$3.0460	$3.0730	

BILLING UNITS

FIXED														
TETCO WLA SUPPLY ZONE DEMAND	Dth	8,593	8,575	8,575	8,575	8,575	8,593	8,593	8,593	8,593	8,593	8,593	8,593	
TETCO ELA SUPPLY ZONE DEMAND	Dth	8,593	8,575	8,575	8,575	8,575	8,593	8,593	8,593	8,593	8,593	8,593	8,593	
TETCO M1 TO M3 DEMAND	Dth	8,593	8,575	8,575	8,575	8,575	8,593	8,593	8,593	8,593	8,593	8,593	8,593	
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	102,000
VARIABLE														
PURCHASE VOLUMES	Dth	268,609	279,773	279,773	252,698	279,773	268,609	277,563	268,609	277,563	277,563	268,609	277,563	3,276,705
TETCO USAGE WLA TO M3	Dth	257,784	265,813	265,813	240,089	265,813	257,784	266,377	257,784	266,377	266,377	257,784	266,377	3,134,170
ALGONQUIN USAGE	Dth	255,000	263,500	263,500	238,000	263,500	255,000	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	255,000	263,500	255,000	263,500	263,500	255,000	263,500	3,102,500

FUEL USE %

TETCO WLA TO M3 FUEL	%	4.03%	4.99%	4.99%	4.99%	4.99%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	
ALGONQUIN AFT-E FUEL	%	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	

TRANSPORTATION COST

FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$	$24,275	$24,223	$24,223	$24,223	$24,223	$24,275	$24,275	$24,275	$24,275	$24,275	$24,275	$24,275	$291,090
TETCO ELA SUPPLY ZONE DEMAND	$	$20,408	$20,365	$20,365	$20,365	$20,365	$20,408	$20,408	$20,408	$20,408	$20,408	$20,408	$20,408	$244,722
TETCO M1 TO M3 DEMAND	$	$91,805	$91,611	$91,611	$91,611	$91,611	$91,805	$91,805	$91,805	$91,805	$91,805	$91,805	$91,805	$1,100,888
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	$55,874	$670,487
VARIABLE														
TETCO USAGE WLA TO M3	$	$21,860	$22,541	$22,541	$20,360	$22,541	$21,860	$22,589	$21,860	$22,589	$22,589	$21,860	$22,589	$265,778
ALGONQUIN USAGE	$	$3,213	$3,320	$3,320	$2,999	$3,320	$3,213	$3,320	$3,213	$3,320	$3,320	$3,213	$3,320	$39,092
PURCHASE COST	$	$804,753	$905,906	$943,116	$848,561	$919,894	$817,109	$833,798	$812,542	$849,619	$853,783	$818,183	$852,950	$10,260,214
TOTAL FIXED	$	$192,362	$192,073	$192,073	$192,073	$192,073	$192,362	$192,362	$192,362	$192,362	$192,362	$192,362	$192,362	$2,307,187
TOTAL VARIABLE	$	$829,826	$931,767	$968,977	$871,920	$945,755	$842,182	$859,707	$837,615	$875,528	$879,692	$843,256	$878,859	$10,565,083
DELIVERED VOLUMES AT NYMEX	$	$784,380	$874,820	$905,386	$813,484	$885,360	$782,850	$799,986	$781,830	$815,533	$817,904	$786,420	$818,958	$9,866,911
NET NON-GAS VARIABLE COST	$	$45,446	$56,947	$63,591	$58,436	$60,395	$59,332	$59,721	$55,785	$59,996	$61,788	$56,836	$59,901	$698,173
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1782**	**$0.2161**	**$0.2413**	**$0.2455**	**$0.2292**	**$0.2327**	**$0.2266**	**$0.2188**	**$0.2277**	**$0.2345**	**$0.2229**	**$0.2273**	**$0.2250**
AVERAGE FIXED COST	$/Dth													$22.6195
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.7437**
TOTAL PATH COST	$/Dth													**$0.9687**

REDACTED

Gas Year 2016 - 2017
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
FIXED														
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	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	
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	
VARIABLE														
TETCO USAGE ELA TO M3	$/Dth	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	
ALGONQUIN USAGE	$/Dth	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY AREA BASIS	$/Dth	($0.1000)	($0.0950)	($0.0750)	($0.0700)	($0.0780)	($0.0600)	($0.0650)	($0.0760)	($0.0590)	($0.0470)	($0.0700)	($0.0680)	
NET COST AFTER BASIS	$/Dth	$2.9760	$3.2250	$3.3610	$3.3480	$3.2820	$3.0100	$2.9710	$2.9900	$3.0360	$3.0570	$3.0140	$3.0400	

BILLING UNITS

FIXED														
TETCO ELA SUPPLY ZONE DEMAND	Dth	6,571	6,557	6,557	6,557	6,557	6,571	6,571	6,571	6,571	6,571	6,571	6,571	
TETCO M1 TO M3 DEMAND	Dth	6,571	6,557	6,557	6,557	6,557	6,571	6,571	6,571	6,571	6,571	6,571	6,571	
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
VARIABLE														
PURCHASE VOLUMES	Dth	205,300	213,787	213,787	193,098	213,787	205,300	212,143	205,300	212,143	212,143	205,300	212,143	2,504,231
TETCO USAGE ELA TO M3	Dth	197,129	203,268	203,268	183,597	203,268	197,129	203,700	197,129	203,700	203,700	197,129	203,700	2,396,718
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	%	3.98%	4.92%	4.92%	4.92%	4.92%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
ALGONQUIN AFT-E FUEL	%	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	

TRANSPORTATION COST

FIXED														
TETCO ELA SUPPLY ZONE DEMAND	$	$15,606	$15,573	$15,573	$15,573	$15,573	$15,606	$15,606	$15,606	$15,606	$15,606	$15,606	$15,606	$187,140
TETCO M1 TO M3 DEMAND	$	$70,204	$70,055	$70,055	$70,055	$70,055	$70,204	$70,204	$70,204	$70,204	$70,204	$70,204	$70,204	$841,856
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
VARIABLE														
TETCO USAGE ELA TO M3	$	$16,381	$16,892	$16,892	$15,257	$16,892	$16,381	$16,927	$16,381	$16,927	$16,927	$16,381	$16,927	$199,167
ALGONQUIN USAGE	$	$2,457	$2,539	$2,539	$2,293	$2,539	$2,457	$2,539	$2,457	$2,539	$2,539	$2,457	$2,539	$29,894
PURCHASE COST	$	$610,973	$689,462	$718,537	$646,491	$701,648	$617,953	$630,278	$613,847	$644,067	$648,522	$618,774	$644,916	$7,785,467
TOTAL FIXED	$	$128,537	$128,356	$128,356	$128,356	$128,356	$128,537	$128,537	$128,537	$128,537	$128,537	$128,537	$128,537	$1,541,721
TOTAL VARIABLE	$	$629,811	$708,893	$737,968	$664,041	$721,079	$636,791	$649,744	$632,685	$663,533	$667,988	$637,612	$664,382	$8,014,528
DELIVERED VOLUMES AT NYMEX	$	$599,820	$668,980	$692,354	$622,076	$677,040	$598,650	$611,754	$597,870	$623,643	$625,456	$601,380	$626,262	$7,545,285
NET NON-GAS VARIABLE COST	$	$29,991	$39,913	$45,614	$41,965	$44,039	$38,141	$37,990	$34,815	$39,891	$42,532	$36,232	$38,120	$469,243
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1538**	**$0.1981**	**$0.2264**	**$0.2306**	**$0.2186**	**$0.1956**	**$0.1885**	**$0.1785**	**$0.1980**	**$0.2111**	**$0.1858**	**$0.1892**	**$0.1978**
AVERAGE FIXED COST	$/Dth													$19.7657
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.6498**
TOTAL PATH COST	$/Dth													**$0.8476**

REDACTED

Gas Year 2016 - 2017
MAUMEE/DOWNINGTON COLUMBIA PATH TO CITY GATE
CITY GATE DELIVERED MDQ = 3,000

UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
COLUMBIA FTS DEMAND	$/Dth	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	
ALGONQUIN 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	
VARIABLE														
COLUMBIA USAGE	$/Dth	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
ALGONQUIN USAGE	$/Dth	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY BASIS MAUMEE	$/Dth	($0.1620)	($0.1550)	($0.1600)	($0.1500)	($0.1600)	($0.1100)	($0.1650)	($0.1680)	($0.1670)	($0.1780)	($0.2550)	($0.2520)	
SUPPLY BASIS DOWNINGTON	$/Dth	($0.3200)	$0.8800	$3.6900	$3.6800	$0.6000	($0.2950)	($0.4500)	($0.5000)	($0.3930)	($0.4850)	($0.6950)	($0.5800)	
NET COST AFTER BASIS MAUMEE	$/Dth	$2.9140	$3.1650	$3.2760	$3.2680	$3.2000	$2.9600	$2.8710	$2.8980	$2.9280	$2.9260	$2.8290	$2.8560	
NET COST AFTER BASIS DOWNINGTON	$/Dth	$2.7560	$4.2000	$7.1260	$7.0980	$3.9600	$2.7750	$2.5860	$2.5660	$2.7020	$2.6190	$2.3890	$2.5280	

BILLING UNITS

FIXED														
COLUMBIA FTS DEMAND	Dth	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	
ALGONQUIN DEMAND	Dth	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
VARIABLE														
PURCHASE VOLUMES MAUMEE	Dth	77,399	78,180	78,180	70,614	78,180	75,819	78,346	75,819	78,346	78,346	75,819	78,346	
PURCHASE VOLUMES DOWNINGTON	Dth	15,480	15,636	15,636	14,123	15,636	15,164	15,669	15,164	15,669	15,669	15,164	15,669	
COLUMBIA USAGE	Dth	90,983	93,816	93,816	84,737	93,816	90,983	94,015	90,983	94,015	94,015	90,983	94,015	
ALGONQUIN USAGE	Dth	90,000	93,000	93,000	84,000	93,000	90,000	93,000	90,000	93,000	93,000	90,000	93,000	
DELIVERED VOLUMES MAUMEE	Dth	75,000	77,500	77,500	70,000	77,500	75,000	77,500	75,000	77,500	77,500	75,000	77,500	912,500
DELIVERED VOLUMES DOWNINGTON	Dth	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

FUEL USE %

COLUMBIA FUEL	%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
ALGONQUIN AFT-E FUEL	%	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	

TRANSPORTATION COST

FIXED														
COLUMBIA FTS DEMAND	$	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$18,957	$227,485
ALGONQUIN DEMAND	$	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$19,720	$236,642
VARIABLE														
COLUMBIA USAGE	$	$1,774	$1,829	$1,829	$1,652	$1,829	$1,774	$1,833	$1,774	$1,833	$1,833	$1,774	$1,833	$21,570
ALGONQUIN USAGE	$	$1,134	$1,172	$1,172	$1,058	$1,172	$1,134	$1,172	$1,134	$1,172	$1,172	$1,134	$1,172	$13,797
PURCHASE COST MAUMEE	$	$225,542	$247,440	$256,118	$230,768	$250,177	$224,424	$224,932	$219,723	$229,397	$229,241	$214,492	$223,757	$2,776,009
PURCHASE COST DOWNINGTON	$	$42,663	$65,671	$111,422	$100,244	$61,919	$42,079	$40,521	$38,910	$42,338	$41,038	$36,226	$39,612	$662,643
TOTAL FIXED	$	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$38,677	$464,128
TOTAL VARIABLE	$	$271,112	$316,113	$370,542	$333,723	$315,096	$269,411	$268,457	$261,541	$274,741	$273,284	$253,626	$266,373	$3,474,020
DELIVERED VOLUMES AT NYMEX	$	$276,840	$308,760	$319,548	$287,112	$312,480	$276,300	$282,348	$275,940	$287,835	$288,672	$277,560	$289,044	$3,482,439
NET NON-GAS VARIABLE COST	$	-$5,728	$7,353	$50,994	$46,611	$2,616	-$6,889	-$13,891	-$14,399	-$13,094	-$15,388	-$23,934	-$22,671	-$8,419
AVERAGE NON-GAS VARIABLE COST	$/Dth	**-$0.0636**	**$0.0791**	**$0.5483**	**$0.5549**	**$0.0281**	**-$0.0765**	**-$0.1494**	**-$0.1600**	**-$0.1408**	**-$0.1655**	**-$0.2659**	**-$0.2438**	**-$0.0077**
AVERAGE FIXED COST	$/Dth													$12.8924
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.4239**
TOTAL PATH COST	$/Dth													**$0.4162**

REDACTED

Gas Year 2016 - 2017
TENNESSEE ZONE 1 TO CITY GATE
CITY GATE DELIVERED MDQ = 9,500

UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$/Dth	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$/Dth	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY AREA BASIS	$/Dth	($0.1290)	($0.0770)	($0.0880)	($0.0320)	($0.0770)	($0.0730)	($0.0900)	($0.0920)	($0.0530)	($0.0280)	($0.0620)	($0.0620)	
NET COST AFTER BASIS	$/Dth	$2.9470	$3.2430	$3.3480	$3.3860	$3.2830	$2.9970	$2.9460	$2.9740	$3.0420	$3.0760	$3.0220	$3.0460	

BILLING UNITS

FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	Dth	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	114,000
VARIABLE														
PURCHASE VOLUMES	Dth	292,788	302,548	302,548	273,269	302,548	292,788	302,548	292,788	302,548	302,548	292,788	302,548	3,562,256
TENNESSE ZONE 1 TO 6 USAGE	Dth	285,000	294,500	294,500	266,000	294,500	285,000	294,500	285,000	294,500	294,500	285,000	294,500	3,467,500
DELIVERED VOLUMES	Dth	285,000	294,500	294,500	266,000	294,500	285,000	294,500	285,000	294,500	294,500	285,000	294,500	3,467,500

FUEL USE %

TENNESSEE ZONE 1 TO 6 FUEL	%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	

TRANSPORTATION COST

FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$2,441,869
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$	$83,277	$86,053	$86,053	$77,725	$86,053	$83,277	$86,053	$83,277	$86,053	$86,053	$83,277	$86,053	$1,013,204
PURCHASE COST	$	$862,847	$981,162	$1,012,930	$925,289	$993,264	$877,486	$891,306	$870,752	$920,350	$930,637	$884,806	$921,561	$11,072,390
TOTAL FIXED	$	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$203,489	$2,441,869
TOTAL VARIABLE	$	$946,124	$1,067,215	$1,098,983	$1,003,014	$1,079,317	$960,763	$977,359	$954,029	$1,006,403	$1,016,690	$968,083	$1,007,613	$12,085,593
DELIVERED VOLUMES AT NYMEX	$	$876,660	$977,740	$1,011,902	$909,188	$989,520	$874,950	$894,102	$873,810	$911,478	$914,128	$878,940	$915,306	$11,027,724
NET NON-GAS VARIABLE COST	$	$69,464	$89,475	$87,081	$93,826	$89,797	$85,813	$83,257	$80,219	$94,926	$102,562	$89,143	$92,307	$1,057,870
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.2437**	**$0.3038**	**$0.2957**	**$0.3527**	**$0.3049**	**$0.3011**	**$0.2827**	**$0.2815**	**$0.3223**	**$0.3483**	**$0.3128**	**$0.3134**	**$0.3051**
AVERAGE FIXED COST	$/Dth													$21.4199
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.7042**
TOTAL PATH COST	$/Dth													**$1.0093**

REDACTED

Gas Year 2016 - 2017
ALGONQUIN LAMBERTVILLE TO CITY GATE
CITY GATE DELIVERED MDQ = 2,714

UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
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	
VARIABLE														
ALGONQUIN AFT-E USAGE	$/Dth	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY AREA BASIS	$/Dth	($0.8300)	$0.4200	$2.6500	$2.6000	$0.1100	($0.7500)	($0.8650)	($0.8580)	($0.7800)	($0.8500)	($1.0150)	($0.9450)	
NET COST AFTER BASIS	$/Dth	$2.2460	$3.7400	$6.0860	$6.0180	$3.4700	$2.3200	$2.1710	$2.2080	$2.3150	$2.2540	$2.0690	$2.1630	

BILLING UNITS

FIXED														
ALGONQUIN AFT-E DEMAND	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	32,568
VARIABLE														
PURCHASE VOLUMES	Dth	82,309	84,872	84,872	76,659	84,872	82,309	85,053	82,309	85,053	85,053	82,309	85,053	1,000,722
ALGONQUIN AFT-E USAGE	Dth	81,420	84,134	84,134	75,992	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	990,610
DELIVERED VOLUMES	Dth	81,420	84,134	84,134	75,992	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	990,610

FUEL USE %

ALGONQUIN AFT-E FUEL	%	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	

TRANSPORTATION COST

FIXED														
ALGONQUIN AFT-E DEMAND	$	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$214,082
VARIABLE														
ALGONQUIN AFT-E USAGE	$	$1,026	$1,060	$1,060	$957	$1,060	$1,026	$1,060	$1,026	$1,060	$1,060	$1,026	$1,060	$12,482
PURCHASE COST	$	$184,866	$317,423	$516,533	$461,333	$294,507	$190,957	$184,649	$181,738	$196,897	$191,708	$170,297	$183,969	$3,074,878
TOTAL FIXED	$	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$17,840	$214,082
TOTAL VARIABLE	$	$185,892	$318,483	$517,593	$462,291	$295,567	$191,983	$185,709	$182,764	$197,957	$192,769	$171,323	$185,029	$3,087,359
DELIVERED VOLUMES AT NYMEX	$	$250,448	$279,325	$289,084	$259,741	$282,690	$249,959	$255,431	$249,634	$260,395	$261,152	$251,099	$261,488	$3,150,446
NET NON-GAS VARIABLE COST	$	-$64,556	$39,158	$228,509	$202,550	$12,877	-$57,977	-$69,722	-$66,870	-$62,438	-$68,383	-$79,776	-$76,460	-$63,087
AVERAGE NON-GAS VARIABLE COST	$/Dth	**-$0.7929**	**$0.4654**	**$2.7160**	**$2.6654**	**$0.1531**	**-$0.7121**	**-$0.8287**	**-$0.8213**	**-$0.7421**	**-$0.8128**	**-$0.9798**	**-$0.9088**	**-$0.0637**
AVERAGE FIXED COST	$/Dth													$6.5734
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.2161**
TOTAL PATH COST	$/Dth													**$0.1524**

REDACTED

Gas Year 2016 - 2017
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
FIXED														
TENNESSEE ZONE 6 TO 6 DEMAND	$/Dth	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	
VARIABLE														
TENNESSE ZONE 6 TO 6 USAGE	$/Dth	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	
07/29/2016 NYMEX	$/Dth	$3.0760	$3.3200	$3.4360	$3.4180	$3.3600	$3.0700	$3.0360	$3.0660	$3.0950	$3.1040	$3.0840	$3.1080	
SUPPLY AREA BASIS	$/Dth	$0.6400	$2.5280	$5.0010	$4.9360	$2.3050	$0.2710	($0.3440)	($0.3940)	($0.1630)	($0.3390)	($0.4680)	($0.1610)	
NET COST AFTER BASIS	$/Dth	$3.7160	$5.8480	$8.4370	$8.3540	$5.6650	$3.3410	$2.6920	$2.6720	$2.9320	$2.7650	$2.6160	$2.9470	

BILLING UNITS

FIXED														
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
VARIABLE														
PURCHASE VOLUMES	Dth	30,015	31,016	31,016	28,014	31,016	30,015	31,016	30,015	31,016	31,016	30,015	31,016	365,183
TENNESSE 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

FUEL USE %

TENNESSEE ZONE 6 TO 6 FUEL	%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	

TRANSPORTATION COST

FIXED														
TENNESSEE ZONE 6 TO 6 DEMAND	$	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$56,922
VARIABLE														
TENNESSE ZONE 6 TO 6 USAGE	$	$1,068	$1,104	$1,104	$997	$1,104	$1,068	$1,104	$1,068	$1,104	$1,104	$1,068	$1,104	$12,994
PURCHASE COST	$	$111,536	$181,379	$261,678	$234,029	$175,703	$100,280	$83,494	$80,200	$90,937	$85,758	$78,519	$91,403	$1,574,915
TOTAL FIXED	$	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$4,744	$56,922
TOTAL VARIABLE	$	$112,604	$182,482	$262,781	$235,026	$176,806	$101,348	$84,597	$81,268	$92,041	$86,861	$79,587	$92,506	$1,587,909
DELIVERED VOLUMES AT NYMEX	$	$92,280	$102,920	$106,516	$95,704	$104,160	$92,100	$94,116	$91,980	$95,945	$96,224	$92,520	$96,348	$1,160,813
NET NON-GAS VARIABLE COST	$	$20,324	$79,562	$156,265	$139,322	$72,646	$9,248	-$9,519	-$10,712	-$3,904	-$9,363	-$12,933	-$3,842	$427,096
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.6775**	**$2.5665**	**$5.0408**	**$4.9758**	**$2.3434**	**$0.3083**	**-$0.3071**	**-$0.3571**	**-$0.1259**	**-$0.3020**	**-$0.4311**	**-$0.1239**	**$1.1701**
AVERAGE FIXED COST	$/Dth													$4.7435
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.1560**
TOTAL PATH COST	$/Dth													**$1.3261**

REDACTED

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-4
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CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2016 - 2017 GCR PROJECTED PRICES**

August 1, 2016 **UNIT PRICES**

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
PIPELINE FIXED COST UNIT PRICES $/Dth													
ALGONQUIN AFT-E/AFT-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	$6.5734
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.6294	$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	[redacted]											
COLUMBIA FTS DEMAND	$/Dth	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900	$6.1900
DOMINION FTNN DEMAND	$/Dth	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619	$4.1619
IROQUOIS DEMAND	$/Dth	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971
NATIONAL FUEL DEMAND	$/Dth	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860	$3.8860
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204	$21.5204
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199	$21.4199
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$/Dth	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563	$22.7563
TENNESSEE FT-A DEMAND DRACUT	$/Dth	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435	$4.7435
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551	$7.1551
TEXAS EASTERN CDS STX DEMAND M3	$/Dth	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040	$6.8040
TEXAS EASTERN CDS WLA DEMAND M3	$/Dth	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250
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	$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	$2.1890
TEXAS EASTERN CDS 1-3 DEMAND M3	$/Dth	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840	$10.6840
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	$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	$2.7220
TEXAS EASTERN SCT WLA DEMAND M3	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
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	$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	$0.8760
TEXAS EASTERN SCT 1-3 DEMAND M3	$/Dth	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730	$4.2730
TEXAS EASTERN SCT STX DEMAND M2	$/Dth	$2.7220	$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 M2	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
TEXAS EASTERN SCT ELA DEMAND M2	$/Dth	$0.9500	$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 M2	$/Dth	$0.8760	$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 1-2 DEMAND M2	$/Dth	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630	$3.2630
TRANSCANADA DEMAND	$/Dth	$12.8475	$13.2758	$13.2758	$11.9910	$13.2758	$12.8475	$13.2758	$12.8475	$13.2758	$13.2758	$12.8475	$13.2758
TRANSCO DEMAND ZONE 6 TO 6	$/Dth	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306	$0.1306
UNION DEMAND	$/Dth	$2.3040	$2.3808	$2.3808	$2.1504	$2.3808	$2.3040	$2.3808	$2.3040	$2.3808	$2.3808	$2.3040	$2.3808

REDACTED

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2016 - 2017 GCR PROJECTED PRICES**

August 1, 2016

		UNIT PRICES											
		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
PIPELINE FIXED COST BILLING UNITS													
ALGONQUIN AFT-E/AFT-1 DEMAND	DTH	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285
ALGONQUIN AFT-3 DEMAND	DTH	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	DTH	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079
ALGONQUIN AIM DEMAND	DTH	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
COLUMBIA FTS DEMAND	DTH	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
DOMINION FTNN DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
IROQUOIS DEMAND	DTH	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NATIONAL FUEL DEMAND	DTH	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
TENNESSEE FT-A DEMAND ZONE 0 TO 6	DTH	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	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
TENNESSEE FT-A DEMAND ZONE 0 TO 6	DTH	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	DTH	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	DTH	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
TENNESSEE FT-A DEMAND DRACUT	DTH	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000
TENNESSEE FT-A DEMAND ZONE 5 TO 6	DTH	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067
TEXAS EASTERN CDS STX DEMAND M3	DTH	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN CDS WLA DEMAND M3	DTH	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN CDS ELA DEMAND M3	DTH	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN CDS ETX DEMAND M3	DTH	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TEXAS EASTERN CDS 1-3 DEMAND M3	DTH	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TEXAS EASTERN FTS DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
TEXAS EASTERN SCT STX DEMAND M3	DTH	571	571	571	571	571	571	571	571	571	571	571	571
TEXAS EASTERN SCT WLA DEMAND M3	DTH	648	648	648	648	648	648	648	648	648	648	648	648
TEXAS EASTERN SCT ELA DEMAND M3	DTH	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TEXAS EASTERN SCT ETX DEMAND M3	DTH	329	329	329	329	329	329	329	329	329	329	329	329
TEXAS EASTERN SCT 1-3 DEMAND M3	DTH	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TEXAS EASTERN SCT STX DEMAND M2	DTH	401	401	401	401	401	401	401	401	401	401	401	401
TEXAS EASTERN SCT WLA DEMAND M2	DTH	455	455	455	455	455	455	455	455	455	455	455	455
TEXAS EASTERN SCT ELA DEMAND M2	DTH	831	831	831	831	831	831	831	831	831	831	831	831
TEXAS EASTERN SCT ETX DEMAND M2	DTH	231	231	231	231	231	231	231	231	231	231	231	231
TEXAS EASTERN SCT 1-2 DEMAND M2	DTH	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474
TRANSCANADA DEMAND	DTH	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
TRANSCO DEMAND ZONE 6 TO 6	DTH	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
UNION DEMAND	DTH	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025
PIPELINE ALLOCATED TO PEAKING													
TENNESSEE FT-A DEMAND DRACUT	DTH	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)	(28,500)

REDACTED

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2016 - 2017 GCR PROJECTED PRICES**

August 1, 2016

		UNIT PRICES												
		Nov-16	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	
PIPELINE FIXED COST DOLLARS														
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	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
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	$10,725	
ALGONQUIN AIM DEMAND	$	[redacted]												
COLUMBIA FTS DEMAND	$	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	
DOMINION FTNN DEMAND	$	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	
IROQUOIS DEMAND	$	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	
NATIONAL FUEL DEMAND	$	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	$75,321	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	$139,883	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	$128,991	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	$285,163	
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	$263,973	
TENNESSEE FT-A DEMAND DRACUT	$	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	$184,997	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	$14,790	
TEXAS EASTERN CDS STX DEMAND M3	$	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	$94,195	
TEXAS EASTERN CDS WLA DEMAND M3	$	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	
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 1-3 DEMAND M3	$	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	$490,759	
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	$	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	
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	$	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	$8,969	
TEXAS EASTERN SCT STX DEMAND M2	$	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	
TEXAS EASTERN SCT WLA DEMAND M2	$	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	
TEXAS EASTERN SCT ELA DEMAND M2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TEXAS EASTERN SCT ETX DEMAND M2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TEXAS EASTERN SCT 1-2 DEMAND M2	$	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	$4,810	
TRANSCANADA DEMAND	$	$13,002	$13,435	$13,435	$12,135	$13,435	$13,002	$13,435	$13,002	$13,435	$13,435	$13,002	$13,435	
TRANSCO DEMAND ZONE 6 TO 6	$	$4,859	$5,021	$5,021	$4,535	$5,021	$4,859	$5,021	$4,859	$5,021	$5,021	$4,859	$5,021	
UNION DEMAND	$	$2,362	$2,440	$2,440	$2,204	$2,440	$2,362	$2,440	$2,362	$2,440	$2,440	$2,362	$2,440	
WESTERLY LATERAL (Yankee)	$	[redacted]												
	$													
PIPELINE ALLOCATED TO PEAKING														
TENNESSEE FT-A DEMAND DRACUT	$	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	($135,190)	
		($135,190)	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($135,190)**	**($1,622,277)**
TOTAL PIPELINE FIXED DEMAND CHARGES		[redacted]												
TOTAL DEMAND UNITS DTH		5,205,225	5,410,306	5,410,306	4,886,728	5,410,306	5,205,225	5,347,159	4,719,210	4,876,517	4,876,517	4,719,210	5,347,159	61,413,868
100% LOAD FACTOR UNIT VALUE $/DTH														[redacted]
Average rate per unit per month														
AVERAGE SYSTEM VARIABLE UNIT VALUE $/DTH														
Marketer Reconciliation 2015/16														$37,411
Marketer Demand Units DTH		1,012,380	1,046,126	1,046,126	944,888	1,046,126	1,012,380	1,046,126	1,012,380	1,046,126	1,046,126	1,012,380	1,046,126	12,317,290
100% LOAD FACTOR UNIT VALUE $/DTH														**0.0030**
TOTAL AVERAGE SYSTEM UNIT VALUE $/DTH														**$ 0.3119**

REDACTED

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4647
Attachment EDA-4
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National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5

Natural Gas Supply VS. Requirements

Units: DTH

	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	OCT 2017	TOTAL
Forecast Demand													
RI Sales GCR	2,448,062	4,114,762	4,973,224	4,267,565	3,661,287	2,172,286	1,298,037	773,014	561,664	520,513	552,212	1,334,917	26,677,543
Total Demand	2,448,062	4,114,762	4,973,224	4,267,565	3,661,287	2,172,286	1,298,037	773,014	561,664	520,513	552,212	1,334,917	26,677,543
Storage Injections													
TENN 501	0	0	0	0	0	62,552	60,534	60,534	60,534	60,534	120,111	82,679	507,479
GSS 300170	0	0	0	0	0	54,860	54,860	54,860	54,860	54,860	67,306	57,925	399,534
GSS 300168	0	0	0	0	0	9,243	9,243	9,803	9,243	21,856	21,151	21,856	102,394
GSS 300171	0	0	0	0	0	24,546	30,026	24,546	24,546	26,783	25,919	26,783	183,150
GSSTE 600045	0	0	0	0	0	48,024	48,024	48,024	48,024	48,024	94,452	48,024	382,596
TETCO 400515	0	0	0	0	0	7,363	7,363	7,363	7,363	7,851	8,674	8,963	54,941
TETCO 400221	0	0	0	0	0	154,444	154,444	154,444	154,444	164,472	182,038	188,105	1,152,392
TETCO 400185	0	0	0	0	0	6,759	6,759	6,759	6,759	7,213	7,959	8,224	50,430
GSS 300169	0	0	0	0	0	26,793	29,377	26,793	26,793	29,234	28,291	29,234	196,516
COL FSS 9630	0	0	0	0	0	18,095	40,791	40,791	20,396	40,791	26,514	14,277	201,656
TENN 62918	0	0	0	0	0	10,387	12,463	41,664	6,300	43,053	41,664	43,053	198,584
Total Underground Storage	0	0	0	0	0	423,066	453,886	475,583	419,262	504,672	624,080	529,124	3,429,672
LNG PROVIDENCE	0	0	0	0	0	140,706	151,596	146,706	45,365	1,780	95,706	12,501	594,358
LNG EXETER	0	0	0	0	0	6,000	0	0	6,231	25,815	51,000	15,095	104,142
Total LNG Injection	0	0	0	0	0	146,706	151,596	146,706	51,596	27,596	146,706	27,596	698,500
Total Injections	0	0	0	0	0	569,772	605,482	622,288	470,858	532,267	770,786	556,720	4,128,172

Delivered Firm Sales Supply

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENNESSEE ZONE 0 CXN	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 0	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 1	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 4 CXN	348,000	359,600	359,600	324,800	359,600	348,000	337,510	348,000	359,600	359,600	348,000	359,600	4,211,910
TENNESSEE ZONE 4	408,257	383,572	486,469	422,730	334,963	334,147	0	127,126	50,147	92,263	173,576	242,683	3,055,933
TENNESSEE NIAGARA	0	1,067	10,821	3,677	537	0	0	0	0	0	0	0	16,102
TENNESSEE DRACUT	0	24,711	33,498	89,448	27,000	0	0	0	0	0	0	0	174,657
TETCO ELA	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO ETX	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO STX	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO WLA	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO M2	767,219	793,506	793,506	718,621	795,616	774,868	275,994	323,428	532,461	514,207	347,333	798,168	7,434,926
TETCO M3 DELIVERED	454,205	67,665	153,278	142,575	83,106	611,833	681,903	28,090	0	0	20,725	173,368	2,416,749
COLUMBIA MAUMEE	45,364	886,218	891,708	793,836	762,129	24,849	0	0	0	0	0	0	3,404,104
COLUMBIA BROADRUN	38,778	289,464	307,101	247,912	246,797	19,627	0	0	0	0	0	0	1,149,679
COLUMBIA EAGLE	20,508	37,188	70,791	58,689	23,101	44,447	40,791	40,791	20,396	40,791	26,514	14,277	438,285
COLUMBIA DOWNINGTOWN	15,652	27,334	64,348	49,678	14,675	10,910	0	0	0	0	0	0	182,597
TRANSCO LEIDY	36,802	38,067	38,067	34,418	38,106	11,397	2,232	2,160	2,232	2,232	2,160	30,739	238,612
TETCO - DTI - TETCO SCT	2,650	16,432	16,432	14,842	16,432	0	0	0	0	0	0	0	66,789
TETCO to B&W SCT	59,021	63,091	63,091	57,074	63,189	0	0	0	0	0	0	0	305,464
ALGONQUIN - AIM	151,794	258,550	372,735	337,840	137,578	389,946	397,402	363,429	0	0	242,411	229,114	2,880,801
ANE II - DAWN-TENN	0	30,564	30,634	27,649	0	0	0	0	0	0	0	0	88,847
GAZ METRO LNG Refill	0	0	0	0	0	26,706	27,596	26,706	27,596	27,596	26,706	27,596	190,500
GDF SUEZ LNG Refill	0	0	0	0	0	120,000	124,000	120,000	24,000	0	120,000	0	508,000
NEWPORT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

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National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
Non LNG Liquid take	2,348,250	3,277,030	3,692,079	3,323,788	2,902,829	2,570,024	1,735,832	1,233,025	964,836	1,009,094	1,160,720	1,847,950	26,065,456
LNG Liquid take	0	0	0	0	0	146,706	151,596	146,706	51,596	27,596	146,706	27,596	698,500
Total take	2,348,250	3,277,030	3,692,079	3,323,788	2,902,829	2,716,730	1,887,428	1,379,730	1,016,431	1,036,690	1,307,426	1,875,546	26,763,956
Storage Withdrawals													
TENN 501	0	121,053	150,937	122,786	106,238	2,000	0	0	0	0	0	0	503,014
GSS 300170	8,135	117,951	107,860	68,981	85,368	0	0	0	0	0	0	0	388,295
GSS 300168	1,389	13,887	33,328	22,130	30,759	0	0	0	0	0	0	0	101,493
GSS 300171	0	33,527	68,291	56,695	20,598	0	0	0	0	0	0	0	179,111
GSSTE 600045	73,990	76,533	76,533	69,197	76,611	0	0	0	0	0	0	0	372,864
TETCO 400515	0	13,455	13,455	13,469	11,852	0	0	0	0	0	0	0	52,231
TETCO 400221	0	286,127	286,127	288,035	253,471	0	0	0	0	0	0	0	1,113,760
TETCO 400185	0	12,521	12,521	12,605	11,092	0	0	0	0	0	0	0	48,740
GSS 300169	0	44,027	54,033	49,360	43,490	0	0	0	0	0	0	0	190,909
COL FSS 9630	0	46,405	71,533	50,496	23,867	3,705	0	0	0	0	0	0	196,006
TENN 62918	727	47,716	8,482	57,619	78,241	4,051	0	0	0	0	0	0	196,836
LNG PROV	11,090	11,460	357,473	123,769	11,460	11,090	11,460	11,090	11,460	11,460	11,090	11,460	594,358
LNG EXETER	4,482	13,071	40,572	8,636	5,410	4,482	4,631	4,482	4,631	4,631	4,482	4,631	104,142
Total Withdrawal Delivered	99,812	837,733	1,281,145	943,777	758,458	25,328	16,091	15,572	16,091	16,091	15,572	16,091	4,041,759
Total Storage withdrawal	84,240	813,202	883,101	811,373	741,589	9,756	0	0	0	0	0	0	3,343,260
Total Peaking withdrawal	15,572	24,531	398,044	132,405	16,869	15,572	16,091	15,572	16,091	16,091	15,572	16,091	698,500
Total Supply	**2,448,062**	**4,114,762**	**4,973,224**	**4,267,565**	**3,661,287**	**2,595,352**	**1,751,923**	**1,248,596**	**980,926**	**1,025,185**	**1,176,292**	**1,864,041**	**30,107,215**
Storage withdrawals at Storage Facilty													
TENN 501	0	122,128	152,277	123,876	107,181	2,018	0	0	0	0	0	0	507,479
GSS 300170	8,370	121,365	110,982	70,978	87,839	0	0	0	0	0	0	0	399,534
GSS 300168	1,401	14,010	33,624	22,327	31,033	0	0	0	0	0	0	0	102,394
GSS 300171	0	34,297	69,861	57,940	21,051	0	0	0	0	0	0	0	183,150
GSSTE 600045	76,013	78,546	78,546	70,945	78,546	0	0	0	0	0	0	0	382,596
TETCO 400515	0	14,160	14,160	14,160	12,461	0	0	0	0	0	0	0	54,941
TETCO 400221	0	297,008	297,008	297,008	261,367	0	0	0	0	0	0	0	1,152,392
TETCO 400185	0	12,998	12,998	12,998	11,438	0	0	0	0	0	0	0	50,430
GSS 300169	0	45,342	55,647	50,783	44,744	0	0	0	0	0	0	0	196,516
COL FSS 9630	0	47,760	73,622	51,918	24,539	3,818	0	0	0	0	0	0	201,656
TENN 62918	733	48,140	8,557	58,130	78,936	4,087	0	0	0	0	0	0	198,584
	193,200	838,300	920,800	867,700	765,700	8,400	0	0	0	0	0	0	3,429,672

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2016 Estimated GCR
Normal Weather Scenario

Ventyx
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Natural Gas Supply VS. Requirements — Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
07/29/2016 NYMEX	**$3.076**	**$3.320**	**$3.436**	**$3.418**	**$3.360**	**$3.070**	**$3.036**	**$3.066**	**$3.095**	**$3.104**	**$3.084**	**$3.108**	
TENNESSEE ZONE 0 CONNEXION													
Basis	($0.098)	($0.100)	($0.125)	($0.120)	($0.110)	($0.095)	($0.095)	($0.098)	($0.083)	($0.072)	($0.082)	($0.098)	
Usage to Zn 6	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	$0.0315	
Fuel to Zn 6	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	
Total Delivered	$3.1032	$3.3528	$3.4467	$3.4333	$3.3837	$3.1001	$3.0650	$3.0929	$3.1383	$3.1589	$3.1279	$3.1362	
TENNESSEE ZONE 0													
Basis	($0.098)	($0.100)	($0.125)	($0.120)	($0.110)	($0.095)	($0.095)	($0.098)	($0.083)	($0.072)	($0.082)	($0.098)	
Usage to Zn 6	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	$0.3352	
Fuel to Zn 6	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	
Total Delivered	$3.4069	$3.6565	$3.7504	$3.7370	$3.6874	$3.4038	$3.3687	$3.3966	$3.4420	$3.4626	$3.4316	$3.4399	
TENNESSEE ZONE 1													
Basis	($0.129)	($0.077)	($0.088)	($0.032)	($0.077)	($0.073)	($0.090)	($0.092)	($0.053)	($0.028)	($0.062)	($0.062)	
Usage to Zn 6	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	$0.2922	
Fuel to Zn 6	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	
Total Delivered	$3.3197	$3.6238	$3.7317	$3.7707	$3.6649	$3.3711	$3.3187	$3.3475	$3.4173	$3.4523	$3.3968	$3.4214	
TENNESSEE ZONE 4 CONNEXION													
Basis	($1.000)	($0.870)	($0.750)	($0.705)	($0.745)	($0.772)	($0.838)	($0.875)	($0.885)	($0.946)	($1.040)	($1.012)	
Usage to Zn 6	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	
Fuel to Zn 6	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	$2.1027	$2.4799	$2.7179	$2.7452	$2.6463	$2.3266	$2.2257	$2.2187	$2.2378	$2.1854	$2.0704	$2.1229	
TENNESSEE ZONE 4													
Basis	($1.000)	($0.870)	($0.750)	($0.705)	($0.745)	($0.772)	($0.838)	($0.875)	($0.885)	($0.946)	($1.040)	($1.012)	
Usage to Zn 6	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	$0.1137	
Fuel to Zn 6	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	$2.2075	$2.5847	$2.8227	$2.8500	$2.7511	$2.4314	$2.3305	$2.3235	$2.3426	$2.2902	$2.1752	$2.2277	
TENNESSEE NIAGARA													
Basis	($0.259)	($0.218)	($0.194)	($0.178)	($0.092)	($0.411)	($0.566)	($0.565)	($0.565)	($0.565)	($0.566)	($0.566)	
Tenn usage	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	
Tenn Fuel	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	
Total Delivered	$2.9206	$3.2074	$3.3482	$3.3462	$3.3744	$2.7616	$2.5714	$2.6026	$2.6318	$2.6408	$2.6197	$2.6439	
TENNESSEE DRACUT													
Basis	$0.135	$2.062	$4.455	$4.405	$1.935	$0.118	-$0.508	-$0.565	-$0.343	-$0.505	-$0.615	-$0.325	
Usage	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	$0.0356	
Fuel	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	
Total Delivered	$3.2482	$5.4203	$7.9305	$7.8625	$5.3332	$3.2252	$2.5649	$2.5379	$2.7890	$2.6359	$2.5058	$2.8200	
TETCO ELA													
Basis	($0.100)	($0.095)	($0.075)	($0.070)	($0.078)	($0.060)	($0.065)	($0.076)	($0.059)	($0.047)	($0.070)	($0.068)	
Usage to M3	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	3.98%	4.92%	4.92%	4.92%	4.92%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2298	$3.5181	$3.6624	$3.6486	$3.5786	$3.2656	$3.2245	$3.2445	$3.2930	$3.3151	$3.2698	$3.2972	
TETCO ETX													
Basis	($0.094)	($0.150)	($0.158)	($0.107)	($0.112)	($0.101)	($0.094)	($0.097)	($0.070)	($0.050)	($0.090)	($0.091)	
Usage to M3	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	$0.0831	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	3.98%	4.92%	4.92%	4.92%	4.92%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2361	$3.4597	$3.5743	$3.6093	$3.5425	$3.2224	$3.1940	$3.2224	$3.2814	$3.3119	$3.2488	$3.2730	

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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO STX													
Basis	($0.068)	($0.090)	($0.115)	($0.110)	($0.102)	($0.058)	($0.058)	($0.060)	($0.040)	($0.030)	($0.040)	($0.058)	
Usage to M3	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	$0.0886	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	4.07%	5.16%	5.16%	5.16%	5.16%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2720	$3.5376	$3.6344	$3.6206	$3.5674	$3.2762	$3.2404	$3.2699	$3.3216	$3.3416	$3.3100	$3.3163	
TETCO WLA													
Basis	($0.080)	($0.082)	($0.065)	($0.060)	($0.072)	($0.028)	($0.032)	($0.041)	($0.034)	($0.028)	($0.038)	($0.035)	
Usage to M3	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel to M3	4.03%	4.99%	4.99%	4.99%	4.99%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.2542	$3.5361	$3.6773	$3.6635	$3.5892	$3.3027	$3.2626	$3.2848	$3.3227	$3.3385	$3.3069	$3.3353	
TETCO M2													
Basis	($1.250)	($1.082)	($0.940)	($0.940)	($0.993)	($0.867)	($0.955)	($0.979)	($0.965)	($1.031)	($1.124)	($1.091)	
Usage on Tetco	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Tetco	2.24%	2.89%	2.89%	2.89%	2.89%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$1.9591	$2.3955	$2.6635	$2.6448	$2.5295	$2.3489	$2.2228	$2.2290	$2.2734	$2.2145	$2.0976	$2.1566	
TETCO M3 DELIVERED													
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
COLUMBIA MAUMEE													
Basis	($0.162)	($0.155)	($0.160)	($0.150)	($0.160)	($0.110)	($0.165)	($0.168)	($0.167)	($0.178)	($0.255)	($0.252)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
COLUMBIA BROADRUN													
Basis	($0.162)	($0.155)	($0.160)	($0.150)	($0.160)	($0.110)	($0.165)	($0.168)	($0.167)	($0.178)	($0.255)	($0.252)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
COLUMBIA EAGLE													
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.3502	$3.8837	$6.2997	$6.2296	$3.6057	$2.4265	$2.2728	$2.3109	$2.4214	$2.3584	$2.1675	$2.2645	

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Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
COLUMBIA DOWNINGTOWN													
Basis	($0.320)	$0.880	$3.690	$3.680	$0.600	($0.295)	($0.450)	($0.500)	($0.393)	($0.485)	($0.695)	($0.580)	
Usage on Columbia	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	$0.0195	
Usage on AGT	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
Fuel on Columbia	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	2.042%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.8765	$4.3575	$7.3707	$7.3418	$4.1103	$2.8961	$2.7010	$2.6804	$2.8208	$2.7351	$2.4977	$2.6412	
TRANSCO LEIDY													
Basis	($1.295)	($1.200)	($1.205)	($1.160)	($1.118)	($0.960)	($1.022)	($1.062)	($1.067)	($1.130)	($1.208)	($1.185)	
Usage on Transco	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	
Usage on AGT	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	
Fuel on Transco	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Delivered to Algonquin	$1.7954	$2.1356	$2.2470	$2.2741	$2.2580	$2.1256	$2.0292	$2.0192	$2.0433	$1.9891	$1.8907	$1.9379	
Total Delivered	$2.0437	$2.3830	$2.4954	$2.5227	$2.5066	$2.3775	$2.2801	$2.2699	$2.2943	$2.2395	$2.1401	$2.1878	
TETCO to DTI to TETCO SCT													
Basis	($1.250)	($1.082)	($0.940)	($0.940)	($0.993)	($0.867)	($0.955)	($0.979)	($0.965)	($1.031)	($1.124)	($1.091)	
Usage on Dominion	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	$0.0142	
Usage on Tetco	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	
Usage on AGT	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	
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	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Delivered to Tetco	$1.8765	$2.2967	$2.5598	$2.5415	$2.4283	$2.2610	$2.1366	$2.1427	$2.1866	$2.1284	$2.0132	$2.0713	
Delivered to Algonquin	$1.9024	$2.3281	$2.5947	$2.5761	$2.4614	$2.2920	$2.1659	$2.1721	$2.2165	$2.1576	$2.0409	$2.0998	
Total Delivered	$2.1519	$2.5773	$2.8462	$2.8274	$2.7117	$2.5457	$2.4183	$2.4245	$2.4694	$2.4099	$2.2919	$2.3514	
TETCO to B&W SCT													
Basis	($1.250)	($1.082)	($0.940)	($0.940)	($0.993)	($0.867)	($0.955)	($0.979)	($0.965)	($1.031)	($1.124)	($1.091)	
Usage on Tetco	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	$0.0576	
Usage on AGT	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	$0.2287	
Fuel to M3	2.24%	2.89%	2.89%	2.89%	2.89%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	
Fuel on AGT	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.1752	$2.6116	$2.8796	$2.8609	$2.7456	$2.5650	$2.4389	$2.4451	$2.4895	$2.4306	$2.3137	$2.3727	
ALGONQUIN - AIM													
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)	
AGT Usage	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	
AGT Fuel	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	
Total Delivered	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
DAWN TO TENNESSEE - ANE II													
Basis	$0.280	$0.325	$0.365	$0.380	$0.465	$0.150	($0.009)	($0.011)	($0.012)	($0.006)	($0.005)	($0.007)	
Iroquois usage	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	$0.0044	
Tenn usage	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	$0.0860	
Fuel on Union	0.88%	0.99%	1.14%	1.08%	1.01%	0.86%	0.61%	0.51%	0.49%	0.39%	0.39%	0.73%	
Fuel on TransCanada	0.50%	1.48%	1.15%	1.68%	0.28%	0.52%	0.47%	0.44%	0.84%	1.09%	0.86%	0.89%	
Fuel on Iroquois	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on Tenn	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	
Total Delivered	$3.5144	$3.8505	$4.0042	$4.0199	$3.9895	$3.3756	$3.1694	$3.1937	$3.2344	$3.2544	$3.2276	$3.2621	

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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 0 CONNEXION													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.103	$3.353	$3.447	$3.433	$3.384	$3.100	$3.065	$3.093	$3.138	$3.159	$3.128	$3.136	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 0													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.407	$3.656	$3.750	$3.737	$3.687	$3.404	$3.369	$3.397	$3.442	$3.463	$3.432	$3.440	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 1													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.320	$3.624	$3.732	$3.771	$3.665	$3.371	$3.319	$3.347	$3.417	$3.452	$3.397	$3.421	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 4 CONNEXION													
Delivered MMBtu	348,000	359,600	359,600	324,800	359,600	348,000	337,510	348,000	359,600	359,600	348,000	359,600	
Delivered Price	$2.1027	$2.4799	$2.7179	$2.7452	$2.6463	$2.3266	$2.2257	$2.2187	$2.2378	$2.1854	$2.0704	$2.1229	
Total Delivered Cost	$731,739	$891,773	$977,366	$891,627	$951,616	$809,657	$751,210	$772,102	$804,729	$785,870	$720,507	$763,384	
TENNESSEE ZONE 4													
Delivered MMBtu	408,257	383,572	486,469	422,730	334,963	334,147	0	127,126	50,147	92,263	173,576	242,683	
Delivered Price	$2.2075	$2.5847	$2.8227	$2.8500	$2.7511	$2.4314	$2.3305	$2.3235	$2.3426	$2.2902	$2.1752	$2.2277	
Total Delivered Cost	$901,226	$991,420	$1,373,170	$1,204,761	$921,523	$812,446	$0	$295,375	$117,476	$211,301	$377,567	$540,618	
TENNESSEE NIAGARA													
Delivered MMBtu	0	1,067	10,821	3,677	537	0	0	0	0	0	0	0	
Delivered Price	$2.9206	$3.2074	$3.3482	$3.3462	$3.3744	$2.7616	$2.5714	$2.6026	$2.6318	$2.6408	$2.6197	$2.6439	
Total Delivered Cost	$0	$3,422	$36,232	$12,304	$1,812	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE DRACUT													
Delivered MMBtu	0	24,711	33,498	89,448	27,000	0	0	0	0	0	0	0	
Delivered Price	$3.25	$5.42	$7.93	$7.86	$5.33	$3.23	$2.56	$2.54	$2.79	$2.64	$2.51	$2.82	
Total Delivered Cost	$0	$133,940	$265,657	$703,285	$143,998	$0	$0	$0	$0	$0	$0	$0	
TETCO ELA													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.2298	$3.5181	$3.6624	$3.6486	$3.5786	$3.2656	$3.2245	$3.2445	$3.2930	$3.3151	$3.2698	$3.2972	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

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TETCO ETX													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.2361	$3.4597	$3.5743	$3.6093	$3.5425	$3.2224	$3.1940	$3.2224	$3.2814	$3.3119	$3.2488	$3.2730	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO STX													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.272	$3.538	$3.634	$3.621	$3.567	$3.276	$3.240	$3.270	$3.322	$3.342	$3.310	$3.316	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO WLA													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.2542	$3.5361	$3.6773	$3.6635	$3.5892	$3.3027	$3.2626	$3.2848	$3.3227	$3.3385	$3.3069	$3.3353	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO M2													
Delivered MMBtu	767,219	793,506	793,506	718,621	795,616	774,868	275,994	323,428	532,461	514,207	347,333	798,168	
Delivered Price	$1.9591	$2.3955	$2.6635	$2.6448	$2.5295	$2.3489	$2.2228	$2.2290	$2.2734	$2.2145	$2.0976	$2.1566	
Total Delivered Cost	$1,503,029	$1,900,870	$2,113,537	$1,900,643	$2,012,543	$1,820,094	$613,465	$720,907	$1,210,509	$1,138,701	$728,576	$1,721,305	
TETCO M3 DELIVERED													
Delivered MMBtu	454,205	67,665	153,278	142,575	83,106	611,833	681,903	28,090	0	0	20,725	173,368	
Delivered Price	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
Total Delivered Cost	$1,037,006	$256,142	$942,968	$867,342	$291,954	$1,442,660	$1,505,167	$63,054	$0	$0	$43,609	$381,274	
COLUMBIA MAUMEE													
Delivered MMBtu	45,364	886,218	891,708	793,836	762,129	24,849	0	0	0	0	0	0	
Delivered Price	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
Total Delivered Cost	$137,886	$2,917,078	$3,037,077	$2,697,196	$2,536,098	$76,710	$0	$0	$0	$0	$0	$0	
COLUMBIA BROADRUN													
Delivered MMBtu	38,778	289,464	307,101	247,912	246,797	19,627	0	0	0	0	0	0	
Delivered Price	$3.0395	$3.2916	$3.4059	$3.3977	$3.3276	$3.0870	$2.9952	$3.0230	$3.0540	$3.0519	$2.9518	$2.9797	
Total Delivered Cost	$117,866	$952,800	$1,045,958	$842,324	$821,255	$60,590	$0	$0	$0	$0	$0	$0	
COLUMBIA EAGLE													
Delivered MMBtu	20,508	37,188	70,791	58,689	23,101	44,447	40,791	40,791	20,396	40,791	26,514	14,277	
Delivered Price	$2.3502	$3.8837	$6.2997	$6.2296	$3.6057	$2.4265	$2.2728	$2.3109	$2.4214	$2.3584	$2.1675	$2.2645	
Total Delivered Cost	$48,197	$144,429	$445,961	$365,611	$83,294	$107,851	$92,709	$94,267	$49,386	$96,203	$57,470	$32,330	
COLUMBIA DOWNINGTOWN													
Delivered MMBtu	15,652	27,334	64,348	49,678	14,675	10,910	0	0	0	0	0	0	
Delivered Price	$2.8765	$4.3575	$7.3707	$7.3418	$4.1103	$2.8961	$2.7010	$2.6804	$2.8208	$2.7351	$2.4977	$2.6412	
Total Delivered Cost	$45,023	$119,108	$474,284	$364,729	$60,319	$31,596	$0	$0	$0	$0	$0	$0	

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National Grid
2016 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5

Natural Gas Supply VS. Requirements — Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TRANSCO LEIDY													
Delivered MMBtu	36,802	38,067	38,067	34,418	38,106	11,397	2,232	2,160	2,232	2,232	2,160	30,739	
Delivered Price	$2.0437	$2.3830	$2.4954	$2.5227	$2.5066	$2.3775	$2.2801	$2.2699	$2.2943	$2.2395	$2.1401	$2.1878	
Total Delivered Cost	$75,213	$90,716	$94,993	$86,828	$95,514	$27,096	$5,089	$4,903	$5,121	$4,999	$4,623	$67,250	
TETCO -> DTI -> TETCO SCT													
Delivered MMBtu	2,650	16,432	16,432	14,842	16,432	0	0	0	0	0	0	0	
Delivered Price	$2.1519	$2.5773	$2.8462	$2.8274	$2.7117	$2.5457	$2.4183	$2.4245	$2.4694	$2.4099	$2.2919	$2.3514	
Total Delivered Cost	$5,703	$42,350	$46,769	$41,964	$44,560	$0	$0	$0	$0	$0	$0	$0	
TETCO to B&W SCT													
Delivered MMBtu	59,021	63,091	63,091	57,074	63,189	0	0	0	0	0	0	0	
Delivered Price	$2.1752	$2.6116	$2.8796	$2.8609	$2.7456	$2.5650	$2.4389	$2.4451	$2.4895	$2.4306	$2.3137	$2.3727	
Total Delivered Cost	$128,379	$164,770	$181,679	$163,284	$173,493	$0	$0	$0	$0	$0	$0	$0	
ALGONQUIN - AIM													
Delivered MMBtu	151,794	258,550	372,735	337,840	137,578	389,946	397,402	363,429	0	0	242,411	229,114	
Delivered Price	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992	
Total Delivered Cost	$346,565	$978,722	$2,293,072	$2,055,223	$483,319	$919,465	$877,187	$815,792	$0	$0	$510,079	$503,872	
DAWN TO TENNESSEE - ANE II													
Delivered MMBtu	0	30,564	30,634	27,649	0	0	0	0	0	0	0	0	
Delivered Price	$3.5144	$3.8505	$4.0042	$4.0199	$3.9895	$3.3756	$3.1694	$3.1937	$3.2344	$3.2544	$3.2276	$3.2621	
Total Delivered Cost	$0	$117,686	$122,667	$111,145	$0	$0	$0	$0	$0	$0	$0	$0	

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
Total Pipeline Costs	$5,077,832	$9,705,228	$13,451,391	$12,308,268	$8,621,297	$6,108,164	$3,844,827	$2,766,400	$2,187,221	$2,237,074	$2,442,431	$4,010,033	$72,760,166
Total Pipeline Volumes	2,348,250	3,277,030	3,692,079	3,323,788	2,902,829	2,570,024	1,735,832	1,233,025	964,836	1,009,094	1,160,720	1,847,950	26,065,456
WACOG	$2.1624	$2.9616	$3.6433	$3.7031	$2.9700	$2.3767	$2.2150	$2.2436	$2.2669	$2.2169	$2.1042	$2.1700	$2.7914
Injections	0	0	0	0	0	423,066	453,886	475,583	419,262	504,672	624,080	529,124	3,429,672
Value at WACOG	$0	$0	$0	$0	$0	$1,005,499	$1,005,347	$1,067,011	$950,441	$1,118,813	$1,313,213	$1,148,193	$7,608,517
Pipeline Costs less Injections	$5,077,832	$9,705,228	$13,451,391	$12,308,268	$8,621,297	$5,102,666	$2,839,481	$1,699,388	$1,236,780	$1,118,261	$1,129,218	$2,861,840	$65,151,649
Pipeline Volumes less injections	2,348,250	3,277,030	3,692,079	3,323,788	2,902,829	2,146,958	1,281,946	757,442	545,573	504,422	536,640	1,318,826	22,635,784
NYMEX cost of Supplies	$7,223,218	$10,879,738	$12,685,983	$11,360,707	$9,753,506	$6,591,161	$3,891,988	$2,322,317	$1,688,549	$1,565,727	$1,654,998	$4,098,911	$73,716,804
Non-gas cost of delivered supplies													**-$0.3784**

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Attachment EDA-5

Attachment EDA-5

FT-2 Operational Parameters

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

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

Effective Period: November 1, 2016 through October 31, 2017

Underground Storage:

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

November 1	97%
November 15	96%
December 1	95%
December 15	87%
January 1	76%
January 15	67%
February 1	55%
February 15	45%
March 1	35%
March 15	26%
April 1	16%

Peaking Inventory:

Inventory Level allocated on November 1, 2016 = MSQ-P
Injections are not allowed.
Minimum Inventory Levels:

November 1	97%
January 1	92%
February 1	44%
March 1	25%
April 1	23%

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

Attachment EDA-6

Attachment EDA-6

FT-2 Storage Variable Costs

FT-2 Storage Variable Costs

SLF - Weighted Average Loss Factor on Storage Withdrawals

Storage	Withdrawals	Fuel %	Fuel Vol.	Fuel Avg.
TENN 501	507,479	0.00%	0	
GSS 300170	399,534	0.00%	0	
GSS 300168	102,394	0.00%	0	
GSS 300171	183,150	0.00%	0	
GSS-TE 600045	382,596	0.00%	0	
TETCO 400515	54,941	0.64%	352	
TETCO 400221	1,152,392	2.17%	25,007	
TETCO 400185	50,430	2.17%	1,094	
GSS 300169	196,516	0.00%	0	
COL FSS 9630	201,656	0.00%	0	
TENN 62918	198,584	0.00%	0	
	3,429,672		26,453	**0.7713%**

WWCC - Weighted Average Commodity Cost of Storage Withdrawals

Storage	Withdrawals	Unit Cost	Cost	Average
TENN 501	507,479	$0.0087	$4,415	
GSS 300170	399,534	$0.0149	$5,953	
GSS 300168	102,394	$0.0149	$1,526	
GSS 300171	183,150	$0.0149	$2,729	
GSS-TE 600045	382,596	$0.0180	$6,887	
TETCO 400515	54,589	$0.0350	$1,911	
TETCO 400221	1,127,385	$0.0577	$65,050	
TETCO 400185	49,336	$0.0577	$2,847	
GSS 300169	196,516	$0.0149	$2,928	
COL FSS 9630	201,656	$0.0153	$3,085	
TENN 62918	198,584	$0.0087	$1,728	
	3,403,219		$99,058	**$0.0291**

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

Storage	Transported		Fuel %		Fuel Vol.	Fuel Avg.
TENN 501	507,479			0.85%	4,314	
GSS 300170	399,534		1.95%	0.85%	11,121	
GSS 300168	102,394			0.85%	870	
GSS 300171	183,150		1.29%	0.87%	3,935	
GSS-TE 600045	382,596		1.50%	0.87%	9,018	
TETCO 400515	54,589		2.40%	0.87%	1,775	
TETCO 400221	1,127,385			0.87%	9,808	
TETCO 400185	49,336			0.87%	429	
GSS 300169	196,516	1.95%	0.00%	0.87%	5,508	
COL FSS 9630	201,656		2.042%	0.87%	5,836	
TENN 62918	198,584			0.85%	1,688	
	3,403,219				54,303	**1.5956%**

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

Storage	Withdrawals		Unit Cost		Cost	Average
TENN 501	503,014			$0.1137	$57,193	
GSS 300170	388,295		$0.0142	$0.1137	$49,663	
GSS 300168	101,493			$0.1137	$11,540	
GSS 300171	179,111		$0.0014	$0.0126	$2,508	
GSS-TE 600045	372,864		$0.0014	$0.0126	$5,220	
TETCO 400515	52,231		$0.0455	$0.0126	$3,036	
TETCO 400221	1,113,760			$0.0126	$14,033	
TETCO 400185	48,740			$0.0126	$614	
GSS 300169	190,909	$0.0142	$0.0014	$0.0126	$5,384	
COL FSS 9630	196,006		$0.0193	$0.0126	$6,253	
TENN 62918	196,836			$0.1137	$22,380	
	3,343,260				$177,823	**$0.0532**

Testimony of
Ann E. Leary

DIRECT TESTIMONY

OF

ANN E. LEARY

September 1, 2016

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I. Introduction

Q. Please state your name and business address.

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

Q. What is your position and responsibilities within that position?

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

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science in Mechanical Engineering from Cornell University in 1983. In 1985, I joined the Essex County Gas Company as a Staff Engineer. In 1987, I became a planning analyst and later accepted the position of Manager of Rates. Following the merger with Eastern Enterprises in 1998, I became Manager of Pricing for Boston Gas Company. After the merger with KeySpan Energy Delivery, subsequently National Grid, I became the Manager of New England Gas Pricing, the position I hold today.

Q. Have you previously testified or appeared before the PUC?

A. Yes I have. I have testified before the PUC regarding the Company's Gas Cost Recovery (GCR) filings in 2012 through 2015, Docket Nos. 4576, 4520, 4436, and 4346. I also submitted pre-filed testimony in the Company's 2012 Rate Case Filing, Docket No. 4323. In addition, I have testified extensively in several ratemaking and regulatory proceedings before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to propose the GCR factors to become effective on November 1, 2016 for the following services: (1) firm sales service to customers in the Residential Non-Heating and Heating rate classes as well as Commercial and Industrial (C&I) firm sales customers in the Small, Medium, Large, and Extra Large rate classes and (2) transportation services provided to Gas Marketers and the associated Gas Marketer Fixed Charges and factors.

Q. How is your testimony organized?

A. My testimony is composed of four general sections: I. Introduction; II. GCR Rate Development; III. Historical Sales Adjustment; and IV. Bill Impacts.

Q. Are you including any Attachments with your testimony?

A. Yes. I am sponsoring the following Attachments:

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

II. GCR Rate Development

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

A. The proposed GCR factors reflect the load specific (high load and low load) factors necessary for the Company to recover the projected gas costs allocated to firm sales customers for the period November 1, 2016 through October 31, 2017. As shown in the testimony of Company witness Elizabeth D. Arangio on Attachment EDA-1, firm sales customers' gas costs for the period are projected to be approximately $116.9 million for the twelve months ended October 2017. In addition to these projected costs, the GCR factors also include recovery of working capital costs, inventory financing costs, prior period reconciliations, liquefied natural gas (LNG) operation and maintenance (O&M) costs, as well as credits for FT-2 Market Storage Demand and LNG costs allocated to the

Distribution Adjustment Clause (DAC) factors. The table below summarizes the costs and credits included in the 2016-2017 GCR factors:

GCR Component	Amount (millions)	Reference
Firm Gas Costs	$116.9	EDA-1
Working Capital Costs	$0.7	AEL-1, page 2, line 9 and page 3, line 5
Inventory Financing Costs	$0.9	AEL-1, page 3, lines 8-9
Prior Period Deferred Balance (Includes the Marketer Fixed Costs Reconciliation)	$1.6	AEL-1, page 2, lines 10-11 and page 3, line 6
LNG O&M Costs	$1.1	Docket No. 4323, AEL-1, page 2, line 8 and page 3, line 7
FT-2 Marketer Storage Demand Costs	($1.8)	AEL-1, page 2, line 4
LNG Costs Recovered via the DAC Factors	($1.5)	AEL-1, page 2, line 5
Total	$117.9	AEL-1, page 2, line 13 + AEL-1, page 3 line 11

Thus, the GCR factors are intended to recover approximately $117.9 million in net costs over the period November 2016 through October 2017.

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

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

Q. Please describe how the fixed cost component of the proposed GCR factors was developed.

A. The fixed cost component includes all of the fixed costs related to the purchase, storage, and delivery of firm gas for both high load factor and low load factor customers. As shown on Attachment AEL-1, page 2, the fixed cost component is derived by taking the total fixed costs, which are already reduced by Capacity Release credits, less any credits such as Natural Gas Portfolio Management Plan (NGPMP) customer credits, LNG demand costs allocated to the DAC mechanism, and storage demand costs billed to FT-2 Marketers. The FT-2 storage demand costs are calculated by multiplying the FT-2 Demand Charge rate by the forecast of storage and peaking Maximum Daily Quantity (MDQ) to be billed to FT-2 Marketers. Adjustments are also made for supply-related LNG costs, working capital costs, and prior period deferred fixed gas costs under/over-collection balances, including an adjustment for the Marketer fixed cost reconciliation as stipulated in the Settlement Agreement between the Company and the Division of Public Utilities and Carriers (Division) in Docket No. 4199. This results in total fixed gas costs of $29.3 million that are to be recovered over the period November 2016 through October 2017. Finally, because the Company's gas-supply resources are planned so that there is sufficient capacity to meet the needs of firm customers (excluding firm customers with capacity exempt status) under design-winter conditions, the total fixed gas cost to be recovered from customers is allocated between high load factor and low load factor customers. The allocation is based on the proportion of design-winter use of these two

groups of customers. The high load and low load GCR factor for each group is derived using the allocated fixed gas cost and dividing each amount by each group's projected throughput for the upcoming year. Accordingly, the proposed GCR fixed low load factor is $1.1412 per dekatherm while the proposed GCR fixed high load factor is $0.9074 per dekatherm.

Q. Please describe how the Company derived the 2016-2017 throughput forecast used to calculate the High Load and Low Load GCR Factors?

A. The pre-filed direct testimony of Theodore Poe, Jr. supports the 2016-2017 throughput forecast used to derive the GCR factors.

Q. Please describe how the Company calculated the Marketer fixed cost reconciliation balance?

A. In accordance with the Settlement Agreement approved in Docket No. 4199, the Company includes an annual reconciliation of Marketer fixed costs. The Company calculated the Marketer reconciliation by updating the 2015-2016 pipeline surcharge/credit for each path that the Company filed last year and based this update on actual, instead of projected, pipeline capacity costs. The Company then compared the pipeline surcharge/credit approved in Docket No. 4576 for each path with the updated actual pipeline surcharge/credit. The difference was multiplied by the Marketer's actual monthly capacity for the months of November 2015 through July 2016 and forecasted

monthly capacity for the months of August 2016 through October 2016. This results in a Marketer surcharge of $34,124, as shown in Attachment AEL-7 page 1.

The Company also finalized the 2014-2015 Marketer reconciliation that it filed last year in Docket No. 4576 to replace the Marketers' forecasted monthly capacity for the months of August 2015 through October 2015 with their actual monthly capacity. This results in a Marketer surcharge of $37,711 for the 2014-2015 period. In addition, the Company reconciled the actual revenues billed to Marketers during the period November 2015 through October 2016 with the actual 2014-2015 Marketer surcharge. This results in a net Marketer reconciliation balance of $3,287 for the 2014-2015 period.

Therefore, the overall total Marketer reconciliation for the two year period totals $37,411. Attachment AEL-7 shows the calculation of the Marketer reconciliation adjustment for both the 2014/2015 and 2015/2016 periods. In addition to crediting firm sales customers' fixed costs for this amount, the Company included this reconciliation in its calculation of the 2016/2017 pipeline surcharge/credits, as detailed in Ms. Arangio's testimony and shown on Attachment EDA-4.

Q. In Docket No. 4576, the Division's consultant, Bruce R. Oliver of Revilo Hill Associates, Inc. requested that the Company include in future filings additional information regarding the monthly capacity release for each pipeline path that it used to calculate the Marketer Reconciliation, as shown in Attachment AEL-7. Has the Company provided this information in this filing?

A. Yes, the Company has provided the additional back-up detail for monthly capacity release information for each pipeline path in an excel file contained in the CD-ROM that it separately provided to Mr. Oliver with this filing.

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

A. As done last year in Docket No. 4576, the Company calculated the monthly design sales by applying a monthly heat factor to the monthly design degree days. This monthly heat factor was computed by dividing the heating component of the normal sales (normal sales less monthly base use) by normal degree days for each month during the period November 2015 through March 2016. To compute the monthly design sales, the Company summed the monthly base use and the product of the monthly heat factor multiplied by the monthly design degree days. In Attachment AEL-1, pages 13-15, the Company has provided detailed calculations showing the derivation of the monthly design sales.

Q. Please describe how the variable cost component was derived.

A. The variable cost component includes all variable costs of gas such as commodity costs, supply-related LNG O&M, working capital, inventory finance costs, pipeline refunds, and deferred cost balances. As shown on Attachment AEL-1, page 3, line 11, the total variable cost for the period November 2016 through October 2017 is $88,605,517. The variable costs are divided by the projected throughput to obtain a variable cost factor of $3.4171 per dekatherm.

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

A. Based on actual data through July 2016 and forecasted data for the months of August through October 2016, the total estimated deferred balance at October 31, 2016 is an under collection of $1,621,668 as shown in Attachment AEL-1, page 6. This balance is incorporated into the development of the proposed GCR factors for the period November 1, 2016 to October 31, 2017. In addition, the Company shows the projected deferred gas cost balances for November 2016 through October 2017 in Attachment AEL-3.

Q. In Attachment AEL-2, the Company provided the FY16 Annual Gas Cost Reconciliation balances. Does the monthly information shown in Attachment AEL-2 agree with the Monthly Deferred Reports filed in Docket Nos. 4520 and 4576?

A. As stated in the Company's 2016 Annual GCR Reconciliation filing submitted on June 30, 2016, although the year-end March 31, 2016 reconciliation balance of $3,197,068 is

the same as the balance reflected in the May 2016 Monthly Deferred Report in Docket No. 4576 (and the March 31, 2016 balance shown in Attachment AEL-1, page 6), the monthly balances for June 2015 through November 2015 in Attachment AEL-2 differ from the Monthly Deferred Reports filed in Docket Nos. 4520 and 4576 for the 12 months ending March 2016 as a result of the restatement of the quarterly NGPMP credits. The Company has restated the estimated monthly NGPMP credits for the months of April 2015 through December 2015 to the actual credits in the applicable month, as reported in the quarterly NGPMP reports filed in Docket No. 4038. In the May 2016 Monthly Deferred Report, the Company performed the same true up of NGPMP credits for the months of April 2015 through December 2015 and reflected this adjustment in the month of December 2015, along with an adjustment to the November 2015 beginning balance for the interest impact of updating the NGPMP credits realized over the period of April 2015 through October 2015, as well as interest in November and December 2015.

Q. Are there other rates the Company is proposing in this filing?

A. Yes. Consistent with the modifications in Docket No. 4270, the Company is submitting for approval its FT-2 Marketer Demand rate of $8.0484 per MDQ in dekatherm/month, as shown in Attachment AEL-5, as well as the Storage and Peaking charge of $0.0680 per therm for FT-1 firm transportation customers returning to Transitional Sale Service. The Company is also submitting for approval the capacity assignment percentages for the high load and low load factors to be used in the determination of pipeline, underground

storage, and peaking capacity for Marketers. These percentages are set forth in Attachment AEL-6.

Q. In Docket No. 4576, Mr. Oliver requested that the Company include in future filings additional information regarding the capacity assignment percentages provided in Attachment AEL-6. Has the Company provided this additional information in this filing?

A. Yes. The Company has provided the detail calculations of the capacity assignment percentages in an excel file contained in the CD-ROM that is separately provided to Mr. Oliver with this filing.

Q. Please describe how the proposed FT-2 Marketer Demand rate is calculated.

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

The FT-2 Demand rate is derived by first totaling the fixed storage costs, associated inventory finance, working capital charges, and supply-related LNG O&M costs, less any LNG demand credits assigned to the DAC factors and any refunds, if applicable. That total is then divided by the total storage and peaking MDQ for the year to derive a monthly per dekatherm rate to be charged to Marketers. As shown in Attachment AEL-5, the proposed FT-2 Marketer Demand rate is $8.0484 per dekatherm and will be applied to the Marketers' storage and peaking MDQ.

III. Historical Sales Review

Q. Did the Company report negative monthly sales for the period April 2015 through March 2016?

A. Yes, the Company reported a small amount of negative sales during this period. As shown in Attachment AEL-2, page 7**,** of this filing, the Company reported negative sales for its Extra-Large Low Load Factor C&I customer class (line 10) during the months of May and August 2015 and for its Default Transportation Service customer class (line 39) during the month of August 2015. The negative sales totaled 6,805 dekatherms equating to 0.02% of total annual sales.

Q. Has the Company investigated these negative sales?

A. Yes. For the Extra-large Low Load customer class, billing adjustments caused the negative volume. For the Default Transportation Service customer class, the booking of accruals and reversals caused the negative volume.

Q. Please explain how accruals and reversals can result in negative volumes for Default Service customers.

A. As noted above, the Company estimates the usage for Default Transportation Service customers. The Company bases the current month's estimate, or accrual, on the prior month's actual usage. When there is a difference between this estimate and the actual month's usage, there is the potential for a large difference between accrual and actual that will appear in the following month (when the accrual is reversed and replaced with the actual usage), which can lead to negative sales volumes reported in the following month.

Q. Please describe the billing adjustments which resulted in negative sales for the Extra Large Low Load factor rate class in May 2015 and August 2015?

A. The negative sales reported in May 2015 were the result of the cancellation of bills of an Extra Large Low Load factor customer for the period August 2014 through April 2015 in May 2015, with the customer being rebilled in June 2015. The negative sales reported in August 2015 were due to the cancellation in August 2015 of bills of an Extra Large Low Load factor customer for the period April 2015 through June 2015 who was rebilled in August 2015 at lower volumes.

IV. Bill Impacts

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

A. An average residential heating customer using 846 therms per year will experience a total annual bill of $1,135.38 based on the proposed GCR and DAC factors, a decrease of $22.94, or 2.0%, from last year's bills. This decrease of $22.94 is comprised of a decrease of $69.51 as a result of the proposed GCR factor; an increase of $47.26 as a result of the proposed increase in the DAC factor, for which the Company submitted a supplemental filing on September 1, 2016 in Docket No. 4634; and a decrease of $0.69 in Gross Earnings Tax. A summary of annual bill impacts for customers with various levels of usage is provided in Attachment AEL-4.

Q. Does this conclude your testimony?

A. Yes.

Attachments of
Ann E. Leary

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

Attachment AEL-1
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Attachment AEL-1
Gas Cost Recovery Factors

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2016

Line No.	Description	Source: Reference	Source: Line #	High Load[1]	Low Load[2]	FT-2 Mkter[3]
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Cost Factor - $/dktherm	AEL-1 pg 2	Line (17)	$0.9074	$1.1412	
(2)	Variable Cost Factor -$/dktherm	AEL-1 pg 3	Line (13)	$3.4171	$3.4171	
(3)	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$4.3245	$4.5583	
(4)	Uncollectible %	Docket 4323		3.18%	3.18%	
(5)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) / [1 - (4)]		$4.4665	$4.7080	
(6)	**GCR Charge on a per therm basis**	(5) / 10		**$0.4466**	**$0.4708**	
(7)	Current rate effective 11/01/15* - $/therm			$0.5259	$0.5530	
(8)	Decrease- $/therm	(6) - (7)		($0.0793)	($0.0822)	
(9)	Percent Decrease	(8) / (7)		-15.1%	-14.9%	

* GCR rates approved with the Revised GCR filing per Docket 4576 filed on October 23, 2015

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load

[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

[3] See AEL-5 for calculation of FT-2 rate

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

Line No.	Description	Source: Reference	Source: Line #	Amount	High Load Factor Total	Low Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Costs (net of Cap Rel to marketers)	AEL-1 pg 4	Line (62)	$50,745,639		
	Less:					
(2)	NGPMP Customer Benefit	EDA-1		($13,700,000)		
(3)	Interruptible Costs			$0		
(4)	FT-2 Storage Demand Costs	AEL-5 pg 2	Line (25)	($1,821,075)		
(5)	LNG Demand to DAC[1]			($1,488,790)		
(6)	Refunds			$0		
(7)	Total Credits	sum[(2):(6)]		($17,009,865)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Dkt 4323	Compliance Attachment 6 Schedule MDL-3-GAS	$575,581		
(9)	Working Capital Requirement	AEL-1 pg 8	Line (16)	$283,602		
(10)	Deferred Fixed Cost Over-recovered	AEL-1 pg 6	Line (19)	($5,220,624)		
(11)	Reconciliation Amount from Fixed costs- Marketers	AEL-7 pg 2	Line (50)	($37,411)		
(12)	Total Additions	sum[(8):(11)]		($4,398,853)		
(13)	Total Fixed Costs	(1) + (7) + (12)		$29,336,921		
(14)	Design Winter Sales Percentage	AEL-1 pg 12	Lines (10) & (11)		3.38%	96.62%
(15)	Allocated Supply Fixed Costs	(13) x (14)			$990,515	$28,346,406
(16)	Sales (Dt) Nov 2016 - Oct 2017	AEL-1 pg 11	Line (9)	25,929,986	1,091,593	24,838,394
(17)	**Fixed Factor**	(15) / (16)			**$0.9074**	**$1.1412**

[1] System Balancing Factor (Docket 4339)
Line (16)
Col (e): AEL-1, page 11, Sum of Lines (1), (6), (8)
Col (f): AEL-1, page 11, Sum of Lines (2):(5) and (7)

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

Line No.	Description	Source Reference	Source Line #	Amount
	(a)	(b)	(c)	(d)
(1)	Variable Costs, excluding Refunds	AEL-1 pg 5	Line (91) - Line (85)	$79,849,261
	Less:			
(2)	Non-Firm Sales			$0
(3)	Refunds	AEL-1 pg 5	Line (85)	$0
(4)	Total Credits	sum [(2):(3)]		$0
	Plus:			
(5)	Working Capital	AEL-1 pg 8	Line (32)	$459,741
(6)	Deferred Variable Cost Under-recovered	AEL-1 pg 6	Line (37)	$6,842,292
(7)	Supply Related LNG O&M	Docket 4323	Compliance Attachment 6 Schedule MDL-3-GAS	$572,694
(8)	Inventory Financing - LNG	AEL-1 pg 10	Line (22)	$248,872
(9)	Inventory Financing - Storage	AEL-1 pg 10	Line (12)	$632,657
(10)	Total Additions	sum [(5):(9)]		$8,756,256
(11)	Total Variable Supply Costs	(1) + (4) + (10)		$88,605,517
(12)	Sales (Dt) Nov 2016 - Oct 2017	AEL-1 pg 11	Line (9)	25,929,986
(13)	**Variable Cost Factor**	(11) / (12)		**$3.4171**

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

Line No.	Description	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	[redacted]														
(1)	Algonquin	EDA-2	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$703,472	$8,441,658
(2)	Texas Eastern	EDA-2	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$212,519	$2,550,223
(3)	TETCO	EDA-2	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$513,707	$6,164,485
(4)	Tennessee	EDA-2	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$957,927	$11,495,126
(5)	Tennessee Dracut for peaking	EDA-2	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$135,190	$1,622,277
(6)	NETNE	EDA-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(7)	Iroquois	EDA-2	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$80,115
(8)	Union	EDA-2	$2,362	$2,440	$2,440	$2,204	$2,440	$2,362	$2,440	$2,362	$2,440	$2,440	$2,362	$2,440	$28,733
(9)	Transcanada	EDA-2	$13,002	$13,435	$13,435	$12,135	$13,435	$13,002	$13,435	$13,002	$13,435	$13,435	$13,002	$13,435	$158,187
(10)	Dominion	EDA-2	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$2,235	$26,819
(11)	Transco	EDA-2	$4,859	$5,021	$5,021	$4,535	$5,021	$4,859	$5,021	$4,859	$5,021	$5,021	$4,859	$5,021	$59,114
(12)	National Fuel	EDA-2	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$4,574	$54,886
(13)	AMA Credits	EDA-2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(14)	Columbia	EDA-2	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$293,746	$3,524,957
(15)	Algonquin AIM	EDA-2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(16)	Westerly Lateral	EDA-2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(17)	Less Credits from Mkter Releases	EDA-2	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($705,450)	($8,465,400)
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(22)	Texas Eastern SS-1 Demand	EDA-2	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$80,567	$966,807
(23)	Texas Eastern SS-1 Capacity	EDA-2	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$160,336
(24)	Texas Eastern FSS-1 Demand	EDA-2	$846	$846	$846	$846	$846	$846	$846	$846	$846	$846	$846	$846	$10,150
(25)	Texas Eastern FSS-1 Capacity	EDA-2	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$7,324
(26)	Dominion GSS Demand	EDA-2	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$21,230	$254,761
(27)	Dominion GSS Capacity	EDA-2	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$180,839
(28)	Dominion GSS-TE Demand	EDA-2	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$26,693	$320,312
(29)	Dominion GSS-TE Capacity	EDA-2	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$239,480
(30)	Tennessee FSMA Demand	EDA-2	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$379,467
(31)	Tennessee FSMA Capacity	EDA-2	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$200,574
(32)	Columbia FSS Demand	EDA-2	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$45,841
(33)	Columbia FSS Capacity	EDA-2	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$70,488
(34)	Keyspan LNG Tank Lease Payment	EDA-2	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$1,964,880
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]														
(36)	Algonquin for TETCO SS-1	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
(37)	Algonquin delivery for FSS	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
(38)	TETCO delivery for FSS	EDA-2	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$4,895	$58,736
(39)	Algonquin SCT for SS-1	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
(40)	Algonquin delivery for GSS, GSS-TE	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
(41)	Algonquin SCT delivery for GSS-TE	EDA-2	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$5,900
(42)	Algonquin delivery for GSS Conv	EDA-2	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$242,013
(43)	Tennessee delivery for GSS	EDA-2	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$54,784	$657,406
(44)	Tennessee delivery for FSMA	EDA-2	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$33,489	$401,873
(45)	TETCO delivery for GSS/GSS-TE	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
(46)	TETCO delivery for GSS-TE	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
(47)	TETCO delivery for GSS-TE	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
(48)	TETCO delivery for GSS Conv	EDA-2	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$128,087
(49)	Dominion delivery for GSS Conv	EDA-2	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$8,578	$102,932
(50)	Dominion delivery for GSS	EDA-2	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$22,158	$265,895
(51)	Algonquin delivery for FSS	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
(52)	Columbia Delivery for FSS	EDA-2	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$15,321	$183,851
(53)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(54)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(55)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(56)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(57)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(58)		EDA-2													$0
(59)	Less Credits from Mkter Releases	EDA-2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(61)	**TOTAL STORAGE FIXED**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$15,406,775
(62)	**TOTAL FIXED COSTS**	(21) + (35) + (60)	$4,180,111	$4,159,001	$4,157,663	$4,155,641	$4,029,496	$4,294,433	$4,295,107	$4,294,433	$4,295,107	$4,295,107	$4,294,433	$4,295,107	$50,745,639

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

Line No.	Description	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	VARIABLE SUPPLY COSTS (Includes Injections)														
(63)	Tennessee Zone 0	EDA-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(64)	Tennessee Zone 4	EDA-2	$901,226	$991,420	$1,373,170	$1,204,761	$921,523	$812,446	$0	$295,375	$117,476	$211,301	$377,567	$540,618	$7,746,882
(65)	Tennessee Connexion	EDA-2	$731,739	$891,773	$977,366	$891,627	$951,616	$809,657	$751,210	$772,102	$804,729	$785,870	$720,507	$763,384	$9,851,581
(66)	Tennessee Dracut	EDA-2	$0	$133,940	$265,657	$703,285	$143,998	$0	$0	$0	$0	$0	$0	$0	$1,246,881
(67)	TETCO STX	EDA-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(68)	TETCO ELA	EDA-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(69)	TETCO WLA	EDA-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(70)	TETCO ETX	EDA-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(71)	TRANSCO LEIDY	EDA-2	$75,213	$90,716	$94,993	$86,828	$95,514	$27,096	$5,089	$4,903	$5,121	$4,999	$4,623	$67,250	$562,343
(72)	M3 Delivered	EDA-2	$1,037,006	$256,142	$942,968	$867,342	$291,954	$1,442,660	$1,505,167	$63,054	$0	$0	$43,609	$381,274	$6,831,176
(73)	Maumee	EDA-2	$137,886	$2,917,078	$3,037,077	$2,697,196	$2,536,098	$76,710	$0	$0	$0	$0	$0	$0	$11,402,045
(74)	Broadrun Col	EDA-2	$117,866	$952,800	$1,045,958	$842,324	$821,255	$60,590	$0	$0	$0	$0	$0	$0	$3,840,794
(75)	Columbia Eagle and Downingtown	EDA-2	$93,220	$263,538	$920,244	$730,341	$143,614	$139,447	$92,709	$94,267	$49,386	$96,203	$57,470	$32,330	$2,712,769
(76)	TETCO M2	EDA-2	$1,503,029	$1,900,870	$2,113,537	$1,900,643	$2,012,543	$1,820,094	$613,465	$720,907	$1,210,509	$1,138,701	$728,576	$1,721,305	$17,384,180
(77)	Dominion to TETCO FTS	EDA-2	$5,703	$42,350	$46,769	$41,964	$44,560	$0	$0	$0	$0	$0	$0	$0	$181,347
(78)	ANE to Tennessee	EDA-2	$0	$117,686	$122,667	$111,145	$0	$0	$0	$0	$0	$0	$0	$0	$351,498
(79)	Niagara to Tennessee	EDA-2	$0	$3,422	$36,232	$12,304	$1,812	$0	$0	$0	$0	$0	$0	$0	$53,770
(80)	TETCO to B & W	EDA-2	$128,379	$164,770	$181,679	$163,284	$173,493	$0	$0	$0	$0	$0	$0	$0	$811,606
(81)	Algonquin - AIM	EDA-2	$346,565	$978,722	$2,293,072	$2,055,223	$483,319	$919,465	$877,187	$815,792	$0	$0	$510,079	$503,872	$9,783,295
(82)	Total Pipeline Commodity Charges	sum[(63):(81)]	$5,077,832	$9,705,228	$13,451,391	$12,308,268	$8,621,297	$6,108,164	$3,844,827	$2,766,400	$2,187,221	$2,237,074	$2,442,431	$4,010,033	$72,760,166
(83)	Hedging	EDA-2	$677,663	$865,327	$328,969	$19,204	$11,377	$21,160	($20,612)	($11,807)	$22,615	($46,474)	($56,821)	($121,452)	$1,689,150
(84)	Costs of Injections	EDA-2	$0	$0	$0	$0	$0	($1,005,499)	($1,005,347)	($1,067,011)	($950,441)	($1,118,813)	($1,313,213)	($1,148,193)	($7,608,517)
(85)	Refunds														
(86)	**TOTAL VARIABLE SUPPLY COSTS**	sum[(82):(85)]	$5,755,495	$10,570,555	$13,780,360	$12,327,472	$8,632,674	$5,123,826	$2,818,869	$1,687,581	$1,259,395	$1,071,787	$1,072,398	$2,740,388	$66,840,799
(87)	Underground Storage	EDA-2	$171,714	$2,324,107	$2,523,629	$2,316,638	$2,117,031	$19,872	$0	$0	$0	$0	$0	$0	$9,472,991
(88)	LNG Withdrawals and Trucking	EDA-2	$67,566	$106,440	$1,727,115	$574,503	$73,195	$67,566	$75,018	$74,452	$78,015	$79,399	$78,206	$80,958	$3,082,432
(89)	Storage Delivery Costs	EDA-2	$8,478	$115,453	$121,336	$105,980	$100,521	$1,271	$0	$0	$0	$0	$0	$0	$453,039
(90)	**TOTAL VARIABLE STORAGE COSTS**	sum[(87):(89)]	$247,759	$2,545,999	$4,372,080	$2,997,121	$2,290,747	$88,709	$75,018	$74,452	$78,015	$79,399	$78,206	$80,958	$13,008,462
(91)	**TOTAL VARIABLE COSTS**	(86) + (90)	$6,003,254	$13,116,553	$18,152,440	$15,324,592	$10,923,421	$5,212,535	$2,893,886	$1,762,033	$1,337,410	$1,151,187	$1,150,604	$2,821,345	$79,849,261
(92)	**TOTAL SUPPLY COSTS**	(62) + (91)	$10,183,365	$17,275,555	$22,310,103	$19,480,233	$14,952,918	$9,506,968	$7,188,993	$6,056,466	$5,632,517	$5,446,294	$5,445,037	$7,116,452	$130,594,900
	Storage Costs for FT-2 Calculation														
(93)	**Storage Fixed Costs - Facilities**	(35)	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$400,105	$4,801,259
(94)	**Storage Fixed Costs - Deliveries**	(60)	$834,266	$812,483	$812,483	$812,483	$684,316	$949,927	$949,927	$949,927	$949,927	$949,927	$949,927	$949,927	$10,605,517
(95)	**Total Storage Costs**	sum[(93):(94)]	$1,234,371	$1,212,588	$1,212,588	$1,212,588	$1,084,421	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$15,406,775

REDACTED

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

Line No.	Description	Nov-15 actual	Dec-15 actual	Jan-16 actual	Feb-16 actual	Mar-16 actual	Apr-16 actual	May-16 actual	Jun-16 actual	Jul-16 actual	Aug-16 forecast	Sep-16 forecast	Oct-16 forecast	Nov-Oct
(1)	# of Days in Month	30	31	31	29	31	30	31	30	31	31	30	31	366
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	I. Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	($2,895,427)	($1,787,883)	($8,875,107)	($10,329,090)	($12,878,739)	($14,239,567)	($14,928,683)	($14,318,399)	($13,310,613)	($11,537,505)	($9,298,298)	($7,132,695)	($2,895,427)
(4)	Interest Adj. for NGPMP Credits (Apr15-Oct15)	($11,760)												($11,760)
(5)	Interest Adj. for NGPMP Credits (Nov15-Mar16)	($4,953)	($2,808)											($7,762)
(6)	Supply Fixed Costs (net of cap rel)	$3,748,291	$3,521,947	$3,524,390	$3,558,029	$3,521,866	$3,430,478	$3,549,690	$3,622,469	$3,487,231	$3,862,353	$3,861,680	$3,862,353	$43,550,778
(7)	LNG Demand to DAC	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
(8)	Supply Related LNG O & M	$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
(9)	NGPMP Credits	($783,333)	($7,320,332)	($783,333)	($783,333)	($277,513)	($783,333)	($783,333)	($1,363,515)	($783,333)	($783,333)	($783,333)	($783,333)	($16,011,359)
(10)	Working Capital	$20,867	$19,564	$19,578	$19,771	$19,563	$19,037	$19,723	$20,142	$19,364	$21,524	$21,520	$21,524	$242,176
(11)	Total Supply Fixed Costs	$2,909,723	($3,854,922)	$2,684,534	$2,718,367	$3,187,816	$2,590,081	$2,709,979	$2,202,996	$2,647,160	$3,024,442	$3,023,766	$3,024,442	$26,868,386
(12)	Supply Fixed - Revenue	$1,724,573	$3,223,290	$4,126,326	$5,254,232	$4,531,428	$3,261,277	$2,081,128	$1,178,236	$858,277	$772,008	$848,067	$1,104,529	$28,963,372
(13)	Monthly Under/(Over) Recovery	$1,185,151	($7,078,212)	($1,441,792)	($2,535,866)	($1,343,612)	($671,196)	$628,852	$1,024,760	$1,788,883	$2,252,434	$2,175,698	$1,919,913	($2,094,986)
(14)	Prelim. Ending Under/(Over) Recovery	($1,710,277)	($8,866,095)	($10,316,898)	($12,864,956)	($14,222,351)	($14,910,763)	($14,299,831)	($13,293,639)	($11,521,730)	($9,285,071)	($7,122,600)	($5,212,782)	($5,009,935)
(15)	Month's Average Balance	($2,302,852)	($5,326,989)	($9,596,003)	($11,597,023)	($13,550,545)	($14,575,165)	($14,614,257)	($13,806,019)	($12,416,172)	($10,411,288)	($8,210,449)	($6,172,738)	
(16)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.38%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
(17)	Interest Applied	($2,359)	($6,204)	($12,192)	($13,783)	($17,216)	($17,920)	($18,567)	($16,975)	($15,775)	($13,227)	($10,095)	($7,842)	($152,156)
(18)	Marketer Reconcilation	($58,533)												($58,533)
(19)	Fixed Ending Under/(Over) Recovery	($1,787,883)	($8,875,107)	($10,329,090)	($12,878,739)	($14,239,567)	($14,928,683)	($14,318,399)	($13,310,613)	($11,537,505)	($9,298,298)	($7,132,695)	($5,220,624)	($5,220,624)
(20)	II. Variable Cost Deferred													
(21)	Beginning Under/(Over) Recovery	$14,821,207	$15,087,445	$16,925,969	$21,441,872	$21,975,898	$17,436,635	$13,348,985	$10,671,012	$9,605,781	$8,676,347	$8,347,382	$7,476,882	$14,821,207
(22)														
(23)	Variable Supply Costs	$7,164,301	$13,003,521	$18,939,058	$18,793,285	$11,145,605	$7,022,068	$4,009,303	$2,624,934	$1,530,041	$1,883,516	$1,622,894	$2,792,806	$90,531,332
(24)	Supply Related LNG to DAC	($11,809)	($95)	($95)	($231,803)	($1,967)	$0	$0	$0	$0	$0	$0	$0	($245,769)
(25)	Supply Related LNG O & M	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$572,694
(26)	Inventory Financing - LNG	$30,581	$29,688	$24,819	$16,443	$17,034	$18,463	$20,244	$22,254	$25,515	$33,504	$37,748	$37,832	$314,124
(27)	Inventory Financing - UG	$101,791	$96,132	$76,679	$63,146	$54,296	$60,142	$66,692	$73,294	$79,910	$57,391	$65,595	$72,771	$867,840
(28)	Working Capital	$41,181	$74,869	$109,043	$106,870	$64,161	$40,430	$23,084	$15,113	$8,809	$10,845	$9,344	$16,080	$519,829
(29)	Total Supply Variable Costs	$7,373,771	$13,251,839	$19,197,227	$18,795,665	$11,326,854	$7,188,828	$4,167,049	$2,783,320	$1,692,000	$2,032,980	$1,783,305	$2,967,212	$92,560,050
(30)	Supply Variable - Revenue	$7,122,847	$11,516,237	$14,705,682	$18,287,426	$15,891,138	$11,295,391	$6,860,270	$3,861,009	$2,633,039	$2,372,753	$2,663,527	$3,610,893	$100,820,212
(31)	Monthly Under/(Over) Recovery	$250,924	$1,735,602	$4,491,545	$508,239	($4,564,283)	($4,106,564)	($2,693,222)	($1,077,689)	($941,040)	($339,773)	($880,222)	($643,681)	($8,260,163)
(32)	Prelim. Ending Under/(Over) Recovery	$15,072,131	$16,823,048	$21,417,514	$21,950,111	$17,411,614	$13,330,071	$10,655,763	$9,593,323	$8,664,741	$8,336,574	$7,467,160	$6,833,201	$6,561,045
(33)	Month's Average Balance	$14,946,669	$15,955,247	$19,171,742	$21,695,992	$19,693,756	$15,383,353	$12,002,374	$10,132,168	$9,135,261	$8,506,461	$7,907,271	$7,155,042	
(34)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.38%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
(35)	Interest Applied	$15,314	$18,582	$24,358	$25,786	$25,021	$18,914	$15,249	$12,458	$11,606	$10,807	$9,722	$9,090	$196,907
(36)	Gas Procurement Incentive/(penalty)	$0	$84,340	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$84,340
(37)	Variable Ending Under/(Over) Recovery	$15,087,445	$16,925,969	$21,441,872	$21,975,898	$17,436,635	$13,348,985	$10,671,012	$9,605,781	$8,676,347	$8,347,382	$7,476,882	$6,842,292	$6,842,292
(38)	**GCR Deferred Summary**													
(39)	Beginning Under/(Over) Recovery	$11,925,780	$13,299,562	$8,050,863	$11,112,782	$9,097,159	$3,197,068	($1,579,698)	($3,647,387)	($3,704,833)	($2,861,157)	($950,917)	$344,187	$11,925,780
(40)	Interest Adj. for NGPMP Credits (Apr15-Oct15)	($11,760)												($11,760)
(41)	Interest Adj. for NGPMP Credits (Nov15-Mar16)	($4,953)	($2,808)											($7,762)
(42)	Gas Costs	$10,813,873	$16,496,997	$22,434,976	$22,091,135	$14,637,128	$10,424,170	$7,530,617	$6,219,027	$4,988,895	$5,717,493	$5,456,198	$6,626,782	$133,437,292
(43)	Inventory Finance	$132,373	$125,820	$101,497	$79,589	$71,331	$78,605	$86,937	$95,548	$105,425	$90,895	$103,343	$110,602	$1,181,964
(44)	Working Capital	$62,048	$94,432	$128,621	$126,641	$83,724	$59,467	$42,807	$35,256	$28,173	$32,368	$30,864	$37,603	$762,005
(45)	NGPMP Credits	($783,333)	($7,320,332)	($783,333)	($783,333)	($277,513)	($783,333)	($783,333)	($1,363,515)	($783,333)	($783,333)	($783,333)	($783,333)	($16,011,359)
(46)	Total Costs	$10,224,961	$9,396,917	$21,881,761	$21,514,032	$14,514,670	$9,778,909	$6,877,028	$4,986,316	$4,339,160	$5,057,422	$4,807,071	$5,991,655	$119,369,903
(47)	Revenue	$8,847,420	$14,739,527	$18,832,008	$23,541,658	$20,422,566	$14,556,669	$8,941,398	$5,039,245	$3,491,316	$3,144,761	$3,511,594	$4,715,422	$129,783,584
(48)	Monthly Under/(Over) Recovery	$1,377,541	($5,342,609)	$3,049,753	($2,027,626)	($5,907,896)	($4,777,760)	($2,064,370)	($52,929)	$847,844	$1,912,661	$1,295,477	$1,276,232	($10,413,682)
(49)	Prelim. Ending Under/(Over) Recovery	$13,303,321	$7,956,953	$11,100,616	$9,085,156	$3,189,263	($1,580,692)	($3,644,068)	($3,700,316)	($2,856,989)	($948,496)	$344,560	$1,620,420	$1,492,576
(50)	Month's Average Balance	$12,614,550	$10,628,258	$9,575,739	$10,098,969	$6,143,211	$808,188	($2,611,883)	($3,673,851)	($3,280,911)	($1,904,827)	($303,178)	$982,304	
(51)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.38%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
(52)	Interest Applied	$12,955	$12,378	$12,166	$12,003	$7,805	$994	($3,318)	($4,517)	($4,168)	($2,420)	($373)	$1,248	$44,751
(53)	Gas Purchase Plan Incentives/(Penalties)	$0	$84,340	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$84,340
(54)														
(55)	**Ending Under/(Over) Recovery W/ Interest**	**$13,299,562**	**$8,050,863**	**$11,112,782**	**$9,097,159**	**$3,197,068**	**($1,579,698)**	**($3,647,387)**	**($3,704,833)**	**($2,861,157)**	**($950,917)**	**$344,187**	**$1,621,668**	$1,621,668

Line 4: Additional interest credit earned in the prior period of April 2015 through October 2015 due to actual NGPMP credits filed under Docket No. 4038.

Line 5: Additional interest credit earned in the current period of November 2015 through December 2015 due to actual NGPMP credits in Docket No. 4038 for the prior period of April 2015 through October 2015..

REDACTED

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4647
Attachment AEL-1
Redacted
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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
GCR - Gas Cost Revenue

Line No.	Description	Reference	Nov-16 fcst	Dec-16 fcst	Jan-17 fcst	Feb-17 fcst	Mar-17 fcst	Apr-17 fcst	May-17 fcst	Jun-17 fcst	Jul-17 fcst	Aug-17 fcst	Sep-17 fcst	Oct-17 fcst	Total Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
(1)	**I. Fixed Cost Revenue --**														
(2)	(a) Low Load dth	AEL-1 pg 11, sum [Line (2):(5), (7)]	1,945,918	3,234,222	4,234,337	4,351,706	3,738,466	2,790,929	1,640,767	799,031	423,728	371,050	425,917	882,322	24,838,394
(3)	Fixed Cost Factor	AEL-1 pg 1, Line 1, col (e)	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	$1.1412	
(4)	Low Load Revenue	(2) * (3)	$2,220,682	$3,690,894	$4,832,226	$4,966,167	$4,266,337	$3,185,008	$1,872,443	$911,854	$483,558	$423,442	$486,057	$1,006,906	$28,345,574
(5)	(b) High Load dth	AEL-1 pg 11, sum [Line (1), (6), (8)]	89,789	120,556	143,733	145,837	130,833	108,300	81,007	60,995	50,208	48,800	50,245	61,288	1,091,593
(6)	Fixed Cost Factor	AEL-1 pg 1, Line 1, col (d)	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	$0.9074	
(7)	High Load Revenue	(5) * (6)	$81,475	$109,393	$130,424	$132,332	$118,718	$98,271	$73,506	$55,347	$45,559	$44,282	$45,593	$55,613	$990,513
(8)	sub-total Dth	(2) + (5)	2,035,708	3,354,779	4,378,071	4,497,543	3,869,298	2,899,229	1,721,774	860,026	473,936	419,850	476,163	943,610	25,929,986
(9)	FT-2 Storage Revenue from	[AEL-5 pg 2, Line (25)] / 12	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$151,756	$1,821,075
(10)	**TOTAL Fixed Revenue**	(4) + (7) + (9)	**$2,453,913**	**$3,952,043**	**$5,114,406**	**$5,250,255**	**$4,536,811**	**$3,435,035**	**$2,097,705**	**$1,118,957**	**$680,873**	**$619,480**	**$683,406**	**$1,214,275**	**$31,157,162**
(11)	**II. Variable Cost Revenue --**														
(12)	(a) Firm Sales dth	(8)	2,035,708	3,354,779	4,378,071	4,497,543	3,869,298	2,899,229	1,721,774	860,026	473,936	419,850	476,163	943,610	25,929,986
(13)	Variable Cost Factor	AEL-1 pg 1, Line (2)	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	$3.4171	
(14)	Variable Revenue	(12) * (13)	$6,956,217	$11,463,614	$14,960,306	$15,368,553	$13,221,780	$9,906,954	$5,883,474	$2,938,796	$1,619,486	$1,434,670	$1,627,096	$3,224,411	$88,605,357
(15)	**TOTAL Variable Revenue**	(14)	**$6,956,217**	**$11,463,614**	**$14,960,306**	**$15,368,553**	**$13,221,780**	**$9,906,954**	**$5,883,474**	**$2,938,796**	**$1,619,486**	**$1,434,670**	**$1,627,096**	**$3,224,411**	**$88,605,357**
(16)	**Total Gas Cost Revenue**	(10) + (15)	**$9,410,130**	**$15,415,657**	**$20,074,712**	**$20,618,808**	**$17,758,591**	**$13,341,989**	**$7,981,179**	**$4,057,753**	**$2,300,359**	**$2,054,150**	**$2,310,502**	**$4,438,686**	**$119,762,519**

REDACTED

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

Line No.	Description	Source	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
(1)	**Fixed Costs**	AEL-3, Line (4)	$4,180,111	$4,159,001	$4,157,663	$4,155,641	$4,029,496	$4,294,433	$4,295,107	$4,294,433	$4,295,107	$4,295,107	$4,294,433	$4,295,107	$50,745,639
(2)	Capacity Release Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(3)	Less: LNG Demand to DAC	AEL-3, Line 7	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
(4)	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6)	Allowable Working Capital Costs	sum[(1):(5)]	$4,056,045	$4,034,935	$4,033,597	$4,031,575	$3,905,430	$4,170,367	$4,171,041	$4,170,367	$4,171,041	$4,171,041	$4,170,367	$4,171,041	$49,256,849
(7)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(8)	Working Capital Requirement	[(6) * (7)] / 365	$239,029	$237,785	$237,706	$237,587	$230,153	$245,766	$245,806	$245,766	$245,806	$245,806	$245,766	$245,806	
(9)	Cost of Capital	Dkt 4323	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
(10)	Return on Working Capital Requirement	(8) * (9)	$17,330	$17,239	$17,234	$17,225	$16,686	$17,818	$17,821	$17,818	$17,821	$17,821	$17,818	$17,821	
(11)	Weighted Cost of Debt	Dkt 4323	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
(12)	Interest Expense	(8) * (11)	$6,143	$6,111	$6,109	$6,106	$5,915	$6,316	$6,317	$6,316	$6,317	$6,317	$6,316	$6,317	
(13)	Taxable Income	(10) - (12)	$11,187	$11,128	$11,125	$11,119	$10,771	$11,502	$11,504	$11,502	$11,504	$11,504	$11,502	$11,504	
(14)	1 - Combined Tax Rate	Dkt 4323	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
(15)	Return and Tax Requirement	(13) / (14)	$17,210	$17,121	$17,115	$17,106	$16,571	$17,695	$17,698	$17,695	$17,698	$17,698	$17,695	$17,698	
(16)	**Fixed Working Capital Requirement**	(12) + (15)	$23,353	$23,232	$23,224	$23,212	$22,486	$24,011	$24,015	$24,011	$24,015	$24,015	$24,011	$24,015	$283,602
(17)	**Variable Costs**	AEL-3, Line (19)	$6,003,254	$13,116,553	$18,152,440	$15,324,592	$10,923,421	$5,212,535	$2,893,886	$1,762,033	$1,337,410	$1,151,187	$1,150,604	$2,821,345	$79,849,261
(18)	Less: Non-firm Sales														$0
(19)	Less: Supply Refunds														$0
(20)	Less: Balancing Related LNG Commodity to DAC	AEL-3, Line 20	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Allowable Working Capital Costs	sum[(17):(21)]	$6,003,254	$13,116,553	$18,152,440	$15,324,592	$10,923,421	$5,212,535	$2,893,886	$1,762,033	$1,337,410	$1,151,187	$1,150,604	$2,821,345	$79,849,261
(23)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(24)	Working Capital Requirement	[(22) * (23)] / 365	$353,781	$772,978	$1,069,751	$903,101	$643,734	$307,183	$170,541	$103,839	$78,816	$67,841	$67,807	$166,266	
(25)	Cost of Capital	Dkt 4323	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
(26)	Return on Working Capital Requirement	(24) * (25)	$25,649	$56,041	$77,557	$65,475	$46,671	$22,271	$12,364	$7,528	$5,714	$4,918	$4,916	$12,054	
(27)	Weighted Cost of Debt	Dkt 4323	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
(28)	Interest Expense	(24) * (27)	$9,092	$19,866	$27,493	$23,210	$16,544	$7,895	$4,383	$2,669	$2,026	$1,744	$1,743	$4,273	
(29)	Taxable Income	(26) - (28)	$16,557	$36,175	$50,064	$42,265	$30,127	$14,376	$7,981	$4,860	$3,689	$3,175	$3,173	$7,781	
(30)	1 - Combined Tax Rate	Dkt 4323	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
(31)	Return and Tax Requirement	(29) / (30)	$25,472	$55,654	$77,022	$65,023	$46,349	$22,117	$12,279	$7,476	$5,675	$4,885	$4,882	$11,971	
(32)	**Variable Working Capital Requirement**	(28) + (31)	$34,564	$75,520	$104,515	$88,233	$62,893	$30,012	$16,662	$10,145	$7,700	$6,628	$6,625	$16,244	$459,741

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The Narragansett Electric Company
d/b/a National Grid
Docket No. 4647
Attachment AEL-1
Redacted
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Storage Fixed Cost Working Capital Calculation for FT-2 Demand Rate (see AEL-5 pg 2)

Line No.	Description	Source	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
(33)	**Storage Fixed Costs**	AEL-1 pg 4, Line (61)	$1,234,371	$1,212,588	$1,212,588	$1,212,588	$1,084,421	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$1,350,032	$15,406,775
(34)	Less: LNG Demand to DAC	AEL-3, Line 7	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
(35)	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(36)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(37)	Allowable Working Capital Costs	sum[(33):(36)]	$1,110,305	$1,088,522	$1,088,522	$1,088,522	$960,355	$1,225,966	$1,225,966	$1,225,966	$1,225,966	$1,225,966	$1,225,966	$1,225,966	$13,917,986
(38)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(39)	Working Capital Requirement	[(37) * (38)] / 365	$65,432	$64,148	$64,148	$64,148	$56,595	$72,248	$72,248	$72,248	$72,248	$72,248	$72,248	$72,248	
(40)	Cost of Capital	Dkt 4323	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
(41)	Return on Working Capital Requirement	(39) * (40)	$4,744	$4,651	$4,651	$4,651	$4,103	$5,238	$5,238	$5,238	$5,238	$5,238	$5,238	$5,238	
(42)	Weighted Cost of Debt	Dkt 4323	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
(43)	Interest Expense	(39) * (42)	$1,682	$1,649	$1,649	$1,649	$1,454	$1,857	$1,857	$1,857	$1,857	$1,857	$1,857	$1,857	
(44)	Taxable Income	(41) - (43)	$3,062	$3,002	$3,002	$3,002	$2,649	$3,381	$3,381	$3,381	$3,381	$3,381	$3,381	$3,381	
(45)	1 - Combined Tax Rate	Dkt 4323	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
(46)	Return and Tax Requirement	(44) / (45)	$4,711	$4,619	$4,619	$4,619	$4,075	$5,202	$5,202	$5,202	$5,202	$5,202	$5,202	$5,202	
(47)	**Storage Fixed Working Capital Requirement**	(43) + (46)	$6,393	$6,267	$6,267	$6,267	$5,529	$7,059	$7,059	$7,059	$7,059	$7,059	$7,059	$7,059	$80,134

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

Line No.	Description	Source	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
(1)	**Storage Inventory Balance**	EDA-2 pg 15	$9,420,032	$7,716,432	$5,867,029	$4,172,991	$2,625,570	$3,621,498	$4,638,275	$5,717,263	$6,678,263	$7,809,786	$9,138,715	$10,300,233	
(2)	Hedging														
(3)	Subtotal	(1) + (2)	$9,420,032	$7,716,432	$5,867,029	$4,172,991	$2,625,570	$3,621,498	$4,638,275	$5,717,263	$6,678,263	$7,809,786	$9,138,715	$10,300,233	
(4)	Cost of Capital	Dkt 4323	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
(5)	Return on Working Capital Requirement	(3) * (4)	$682,952	$559,441	$425,360	$302,542	$190,354	$262,559	$336,275	$414,502	$484,174	$566,209	$662,557	$746,767	$5,633,691
(6)	Weighted Cost of Debt	Dkt 4323	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
(7)	Interest Charges Financed	(3) * (6)	$242,095	$198,312	$150,783	$107,246	$67,477	$93,072	$119,204	$146,934	$171,631	$200,711	$234,865	$264,716	$1,997,046
(8)	Taxable Income	(5) - (7)	$440,857	$361,129	$274,577	$195,296	$122,877	$169,486	$217,071	$267,568	$312,543	$365,498	$427,692	$482,051	
(9)	1 - Combined Tax Rate	Dkt 4323	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
(10)	Return and Tax Requirement	(8) / (9)	$678,242	$555,583	$422,426	$300,455	$189,041	$260,748	$333,956	$411,643	$480,835	$562,305	$657,987	$741,617	$5,594,838
(11)	Working Capital Requirement	(7) + (10)	$920,337	$753,895	$573,209	$407,701	$256,518	$353,820	$453,159	$558,577	$652,466	$763,016	$892,852	$1,006,333	$7,591,885
(12)	Storage-Related Inventory Costs	(11) / 12	$76,695	$62,825	$47,767	$33,975	$21,377	$29,485	$37,763	$46,548	$54,372	$63,585	$74,404	$83,861	$632,657
(13)	**LNG Inventory Balance**	EDA-2 pg 17	$3,325,532	$3,219,092	$1,491,978	$917,475	$844,280	$1,518,512	$2,205,170	$2,871,965	$3,098,114	$3,211,057	$3,876,581	$3,987,966	
(14)	Cost of Capital	Dkt 4323	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
(15)	Return on Working Capital Requirement	(13) * (14)	$241,101	$233,384	$108,168	$66,517	$61,210	$110,092	$159,875	$208,217	$224,613	$232,802	$281,052	$289,128	$2,216,160
(16)	Weighted Cost of Debt	Dkt 4323	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
(17)	Interest Charges Financed	(13) * (16)	$85,466	$82,731	$38,344	$23,579	$21,698	$39,026	$56,673	$73,809	$79,622	$82,524	$99,628	$102,491	$785,590
(18)	Taxable Income	(15) - (17)	$155,635	$150,654	$69,825	$42,938	$39,512	$71,066	$103,202	$134,408	$144,992	$150,277	$181,424	$186,637	
(19)	1 - Combined Tax Rate	Dkt 4323	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
(20)	Return and Tax Requirement	(18) / (19)	$239,438	$231,775	$107,422	$66,058	$60,788	$109,333	$158,772	$206,781	$223,064	$231,196	$279,114	$287,134	$2,200,876
(21)	Working Capital Requirement	(17) + (20)	$324,904	$314,505	$145,766	$89,637	$82,486	$148,359	$215,445	$280,591	$302,686	$313,720	$378,742	$389,624	$2,986,466
(22)	LNG-Related Inventory Costs	(21) / 12	$27,075	$26,209	$12,147	$7,470	$6,874	$12,363	$17,954	$23,383	$25,224	$26,143	$31,562	$32,469	$248,872
(23)	Total Inventory Financing Costs	(12) + (22)	$103,770	$89,033	$59,915	$41,445	$28,250	$41,848	$55,717	$69,931	$79,596	$89,728	$105,966	$116,330	$881,529

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The Narragansett Electric Company
d/b/a National Grid
Docket No. 4647
Attachment AEL-1
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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Forecasted Throughput (Dth)

Line No.	Rate Class	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	SALES													
(1)	Residential Non-Heating	61,398	89,290	110,313	112,206	98,591	78,155	53,411	35,271	25,629	24,348	25,656	35,674	749,942
(2)	Residential Heating	1,468,822	2,422,361	3,163,979	3,252,058	2,798,847	2,097,234	1,245,874	622,889	333,615	289,355	335,174	684,134	18,714,342
(3)	Small C&I	165,415	315,799	433,065	447,372	375,474	263,850	128,588	29,824	28	25	28	39,202	2,198,668
(4)	Medium C&I	254,663	399,478	510,752	522,834	453,810	348,373	219,911	125,684	81,767	75,158	82,250	135,881	3,210,561
(5)	Large LLF	52,415	88,802	116,353	119,020	101,449	74,903	42,642	18,952	7,967	6,309	8,101	21,542	658,455
(6)	Large HLF	17,142	20,113	22,351	22,569	21,134	18,966	16,331	14,397	13,180	13,048	13,191	14,260	206,682
(7)	Extra Large LLF	4,605	7,782	10,188	10,421	8,887	6,569	3,751	1,682	352	204	364	1,563	56,368
(8)	Extra Large HLF	11,250	11,153	11,069	11,062	11,109	11,179	11,264	11,327	11,399	11,404	11,398	11,354	134,968
(9)	**Total Sales**	2,035,708	3,354,779	4,378,071	4,497,543	3,869,298	2,899,229	1,721,774	860,026	473,936	419,850	476,163	943,610	25,929,986
	TRANSPORTATION													
(10)	FT- Small	8,999	14,333	18,388	18,779	16,201	12,307	7,573	4,097	2,464	2,218	2,484	4,476	112,319
(11)	FT- Medium	200,552	302,473	379,821	388,069	339,766	266,096	175,632	109,040	76,371	72,042	77,135	114,700	2,501,698
(12)	FT- Large LLF	161,095	268,006	349,937	357,796	305,997	227,768	132,694	63,040	30,089	25,175	30,556	70,514	2,022,667
(13)	FT- Large HLF	72,899	86,798	97,270	99,035	92,265	82,038	69,609	60,897	56,230	55,592	56,282	61,882	890,796
(14)	FT- Extra Large LLF	96,935	154,436	197,958	202,172	174,405	132,458	81,479	44,044	26,644	24,028	26,857	48,070	1,209,486
(15)	FT- Extra Large HLF	549,020	587,602	616,543	619,372	600,731	572,570	538,346	513,215	517,532	515,764	517,676	532,016	6,680,387
(16)	**Total FT Transportation**	1,089,500	1,413,648	1,659,917	1,685,222	1,529,366	1,293,237	1,005,334	794,333	709,331	694,818	710,989	831,657	13,417,354
	Total THROUGHPUT													
(17)	Residential Non-Heating	61,398	89,290	110,313	112,206	98,591	78,155	53,411	35,271	25,629	24,348	25,656	35,674	749,942
(18)	Residential Heating	1,468,822	2,422,361	3,163,979	3,252,058	2,798,847	2,097,234	1,245,874	622,889	333,615	289,355	335,174	684,134	18,714,342
(19)	Small C&I	174,414	330,132	451,453	466,152	391,675	276,157	136,161	33,921	2,491	2,243	2,511	43,678	2,310,988
(20)	Medium C&I	455,215	701,951	890,573	910,903	793,576	614,469	395,543	234,724	158,138	147,199	159,385	250,580	5,712,259
(21)	Large LLF	213,509	356,808	466,290	476,816	407,446	302,671	175,337	81,992	38,056	31,484	38,657	92,056	2,681,122
(22)	Large HLF	90,041	106,911	119,621	121,603	113,399	101,004	85,940	75,294	69,410	68,640	69,473	76,143	1,097,479
(23)	Extra Large LLF	101,540	162,218	208,146	212,593	183,292	139,027	85,231	45,726	26,996	24,231	27,220	49,633	1,265,853
(24)	Extra Large HLF	560,270	598,755	627,612	630,434	611,840	583,749	549,611	524,542	528,931	527,168	529,074	543,369	6,815,355
(25)	**Total Throughput**	3,125,208	4,768,426	6,037,988	6,182,765	5,398,665	4,192,466	2,727,108	1,654,359	1,183,267	1,114,668	1,187,152	1,775,267	39,347,340

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

Line No.	Rate Class	Reference	Line #	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Total	%
	(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)
	SALES (dth)									
(1)	Residential Non-Heating	AEL-1 pg 15	Line (70)	70,090	97,034	117,723	121,080	109,244	515,172	2.56%
(2)	Residential Heating	AEL-1 pg 15	Line (71)	1,742,439	2,677,188	3,412,158	3,548,322	3,159,670	14,539,777	72.30%
(3)	Small C&I	AEL-1 pg 15	Line (72)	204,548	354,125	470,892	492,298	430,187	1,952,050	9.71%
(4)	Medium C&I	AEL-1 pg 15	Line (74)	296,466	438,183	548,327	567,770	508,198	2,358,944	11.73%
(5)	Large LLF	AEL-1 pg 15	Line (76)	63,090	98,666	125,858	130,264	115,134	533,012	2.65%
(6)	Large HLF	AEL-1 pg 15	Line (78)	18,157	20,943	23,143	23,587	22,278	108,107	0.54%
(7)	Extra Large LLF	AEL-1 pg 15	Line (80)	5,623	8,689	11,051	11,439	10,137	46,939	0.23%
(8)	Extra Large HLF	AEL-1 pg 15	Line (82)	11,272	11,153	11,069	11,090	11,109	55,693	0.28%
(9)	Total Sales			2,411,685	3,705,981	4,720,222	4,905,851	4,365,956	20,109,696	100.00%
(10)	Low Load Factor	sum[(2:5),(7)]		2,312,166	3,576,851	4,568,286	4,750,093	4,223,326	19,430,723	96.62%
(11)	High Load Factor	sum[(1),(6),(8)]		99,519	129,130	151,935	155,758	142,631	678,973	3.38%

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2016/2017 Design Day Send Out

(12)	Pipeline	174,526	Dktherm
(13)	Underground Storage	42,517	Dktherm
(14)	LNG	140,110	Dktherm
(15)	Total Projected 2016/2017 Design Day	357,153	Dktherm

Derivation of Monthly Design Sales

Normal Volumes (Dth)

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	61,398	89,290	110,313	112,206	98,591	78,155	53,411	35,271	25,629	24,348	25,656	35,674	749,942
(2)	Residential Heating	1,468,822	2,422,361	3,163,979	3,252,058	2,798,847	2,097,234	1,245,874	622,889	333,615	289,355	335,174	684,134	18,714,342
(3)	Small C&I	165,415	315,799	433,065	447,372	375,474	263,850	128,588	29,824	28	25	28	39,202	2,198,668
(4)	Small Transport	8,999	14,333	18,388	18,779	16,201	12,307	7,573	4,097	2,464	2,218	2,484	4,476	112,319
(5)	Medium C&I	254,663	399,478	510,752	522,834	453,810	348,373	219,911	125,684	81,767	75,158	82,250	135,881	3,210,561
(6)	Med Transport	200,552	302,473	379,821	388,069	339,766	266,096	175,632	109,040	76,371	72,042	77,135	114,700	2,501,698
(7)	Large Low Load	52,415	88,802	116,353	119,020	101,449	74,903	42,642	18,952	7,967	6,309	8,101	21,542	658,455
(8)	Large Low Load- Transport	161,095	268,006	349,937	357,796	305,997	227,768	132,694	63,040	30,089	25,175	30,556	70,514	2,022,667
(9)	Large High Load	17,142	20,113	22,351	22,569	21,134	18,966	16,331	14,397	13,180	13,048	13,191	14,260	206,682
(10)	Large High Load- Transport	72,899	86,798	97,270	99,035	92,265	82,038	69,609	60,897	56,230	55,592	56,282	61,882	890,796
(11)	XL Low Load	4,605	7,782	10,188	10,421	8,887	6,569	3,751	1,682	352	204	364	1,563	56,368
(12)	XL Low Load-Transport	96,935	154,436	197,958	202,172	174,405	132,458	81,479	44,044	26,644	24,028	26,857	48,070	1,209,486
(13)	XL High Load	11,250	11,153	11,069	11,062	11,109	11,179	11,264	11,327	11,399	11,404	11,398	11,354	134,968
(14)	XL High Load-Transport	549,020	587,602	616,543	619,372	600,731	572,570	538,346	513,215	517,532	515,764	517,676	532,016	6,680,387
(15)	**Total**	3,125,208	4,768,426	6,037,988	6,182,765	5,398,665	4,192,466	2,727,108	1,654,359	1,183,267	1,114,668	1,187,152	1,775,267	39,347,340
(16)	HLF	711,708	794,957	857,546	864,243	823,829	762,908	688,962	635,107	623,971	620,156	624,204	655,186	8,662,776
(17)	LLF	2,413,500	3,973,469	5,180,442	5,318,522	4,574,836	3,429,558	2,038,146	1,019,252	559,296	494,512	562,949	1,120,081	30,684,564

Baseload

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
		30	31	31	29	31	30	31	30	31	31	30	31	
(18)	Residential Non-Heating	24,663	25,485	25,485	23,841	25,485	24,663	25,485	24,663	25,485	24,348	24,663	25,485	299,751
(19)	Residential Heating	312,438	322,853	322,853	302,024	322,853	312,438	322,853	312,438	322,853	289,355	312,438	322,853	3,778,250
(20)	Small C&I	26	27	27	25	27	26	27	26	27	25	26	27	317
(21)	Small Transport	2,337	2,414	2,414	2,259	2,414	2,337	2,414	2,337	2,414	2,218	2,337	2,414	28,309
(22)	Medium C&I	77,992	80,592	80,592	75,392	80,592	77,992	80,592	77,992	80,592	75,158	77,992	80,592	946,067
(23)	Med Transport	73,548	76,000	76,000	71,097	76,000	73,548	76,000	73,548	76,000	72,042	73,548	76,000	893,330
(24)	Large Low Load	7,297	7,540	7,540	7,053	7,540	7,297	7,540	7,297	7,540	6,309	7,297	7,540	87,788
(25)	Large Low Load- Transport	27,985	28,918	28,918	27,052	28,918	27,985	28,918	27,985	28,918	25,175	27,985	28,918	337,672
(26)	Large High Load	12,854	13,282	13,282	12,426	13,282	12,854	13,282	12,854	13,180	13,048	12,854	13,282	156,482
(27)	Large High Load- Transport	54,817	56,644	56,644	52,989	56,644	54,817	56,644	54,817	56,230	55,592	54,817	56,644	667,298
(28)	XL Low Load	300	310	310	290	310	300	310	300	310	204	300	310	3,550
(29)	XL Low Load-Transport	25,281	26,124	26,124	24,438	26,124	25,281	26,124	25,281	26,124	24,028	25,281	26,124	306,334
(30)	XL High Load	11,153	11,153	11,069	10,781	11,109	11,153	11,264	11,153	11,399	11,404	11,153	11,354	134,144
(31)	XL High Load-Transport	505,752	522,610	522,610	488,893	522,610	505,752	522,610	505,752	517,532	515,764	505,752	522,610	6,158,247
(32)	Total	1,136,442	1,173,951	1,173,867	1,098,560	1,173,907	1,136,442	1,174,063	1,136,442	1,168,604	1,114,668	1,136,442	1,174,152	13,797,539
(33)	HLF	609,238	629,175	629,090	588,930	629,130	609,238	629,286	609,238	623,827	620,156	609,238	629,375	7,415,922
(34)	LLF	527,203	544,777	544,777	509,630	544,777	527,203	544,777	527,203	544,777	494,512	527,203	544,777	6,381,617

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Derivation of Monthly Design Sales

Heat Volumes

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(35)	Residential Non-Heating	36,735	63,805	84,828	88,365	73,106	53,492	27,926	10,608	144	0	993	10,189	450,191
(36)	Residential Heating	1,156,383	2,099,508	2,841,126	2,950,034	2,475,994	1,784,796	923,021	310,450	10,762	0	22,736	361,281	14,936,092
(37)	Small C&I	165,388	315,772	433,038	447,347	375,447	263,824	128,561	29,797	1	0	2	39,175	2,198,351
(38)	Small Transport	6,663	11,919	15,974	16,521	13,787	9,970	5,159	1,761	49	0	147	2,061	84,010
(39)	Medium C&I	176,671	318,887	430,160	447,442	373,218	270,381	139,320	47,692	1,176	0	4,258	55,289	2,264,494
(40)	Med Transport	127,004	226,473	303,822	316,973	263,767	192,548	99,632	35,492	371	0	3,587	38,700	1,608,368
(41)	Large Low Load	45,118	81,263	108,813	111,966	93,909	67,607	35,103	11,656	427	0	804	14,002	570,667
(42)	Large Low Load- Transport	133,110	239,088	321,020	330,744	277,080	199,783	103,777	35,055	1,172	0	2,571	41,596	1,684,995
(43)	Large High Load	4,288	6,831	9,068	10,143	7,851	6,112	3,049	1,543	0	0	337	978	50,201
(44)	Large High Load- Transport	18,082	30,154	40,626	46,045	35,621	27,221	12,965	6,080	0	0	1,466	5,238	223,499
(45)	XL Low Load	4,305	7,473	9,879	10,132	8,577	6,269	3,442	1,383	42	0	64	1,253	52,817
(46)	XL Low Load-Transport	71,654	128,312	171,834	177,733	148,282	107,177	55,356	18,763	521	0	1,576	21,946	903,152
(47)	XL High Load	97	0	0	281	0	26	0	174	0	0	246	0	824
(48)	XL High Load-Transport	43,268	64,992	93,933	130,479	78,121	66,819	15,736	7,463	0	0	11,924	9,406	522,141
(49)	Total	1,988,767	3,594,475	4,864,121	5,084,205	4,224,758	3,056,024	1,553,045	517,918	14,663	0	50,711	601,115	25,549,801
(50)	HLF	102,470	165,782	228,456	275,313	194,699	153,670	59,676	25,869	144	0	14,966	25,811	1,246,855
(51)	LLF	1,886,296	3,428,692	4,635,665	4,808,892	4,030,059	2,902,354	1,493,369	492,049	14,519	0	35,745	575,304	24,302,947
(52)	**Normal Billing DD**	**579**	**931**	**1099**	**936**	**796**	**453**	**227**	**44**	**1**	**1**	**52**	**339**	**5458**

Heat Factors

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(53)	Residential Non-Heating	63	69	77	94	92	118	123	241	144	-	19	30	82
(54)	Residential Heating	1,997	2,255	2,585	3,152	3,111	3,940	4,066	7,056	10,762	-	437	1,066	2,737
(55)	Small C&I	286	339	394	478	472	582	566	677	1	-	0	116	403
(56)	Small Transport	12	13	15	18	17	22	23	40	49	-	3	6	15
(57)	Medium C&I	305	343	391	478	469	597	614	1,084	1,176	-	82	163	415
(58)	Med Transport	219	243	276	339	331	425	439	807	371	-	69	114	295
(59)	Large Low Load	78	87	99	120	118	149	155	265	427	-	15	41	105
(60)	Large Low Load- Transport	230	257	292	353	348	441	457	797	1,172	-	49	123	309
(61)	Large High Load	7	7	8	11	10	13	13	35	-	-	6	3	9
(62)	Large High Load- Transport	31	32	37	49	45	60	57	138	-	-	28	15	41
(63)	XL Low Load	7	8	9	11	11	14	15	31	42	-	1	4	10
(64)	XL Low Load-Transport	124	138	156	190	186	237	244	426	521	-	30	65	165
(65)	XL High Load	0	-	-	0	-	0	-	4	-	-	5	-	0
(66)	XL High Load-Transport	75	70	85	139	98	148	69	170	-	-	229	28	96
(67)	Total	3,435	3,861	4,426	5,432	5,307	6,746	6,842	11,771	14,663	-	975	1,773	4,681
(68)	**NormalBilling DD**	**579**	**931**	**1099**	**936**	**796**	**453**	**227**	**44**	**1**	**1**	**52**	**339**	**5458**
(69)	**DesignBilling DD**	**716**	**1044**	**1195**	**1030**	**912**	**546**	**217**	**35**	**5**	**10**	**88**	**370**	**6168**

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The Narragansett Electric Company
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Derivation of Monthly Design Sales

Design Sales

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(70)	Residential Non-Heating	70,090	97,034	117,723	121,080	109,244	89,137	52,181	33,101	25,485	24,348	26,344	36,606	802,374
(71)	Residential Heating	1,742,439	2,677,188	3,412,158	3,548,322	3,159,670	2,463,649	1,205,213	559,387	322,853	289,355	350,915	717,172	20,448,321
(72)	Small C&I	204,548	354,125	470,892	492,298	430,187	318,013	122,924	23,729	27	25	29	42,785	2,459,582
(73)	Small Transport	10,576	15,780	19,783	20,438	18,210	14,353	7,346	3,737	2,414	2,218	2,585	4,664	122,107
(74)	Medium C&I	296,466	438,183	548,327	567,770	508,198	403,881	213,774	115,929	80,592	75,158	85,198	140,937	3,474,413
(75)	Med Transport	230,603	329,961	406,361	419,902	378,205	305,626	171,243	101,780	76,000	72,042	79,619	118,239	2,689,580
(76)	Large Low Load	63,090	98,666	125,858	130,264	115,134	88,783	41,096	16,568	7,540	6,309	8,658	22,822	724,788
(77)	Large Low Load- Transport	192,591	297,025	377,979	391,011	346,376	268,783	128,123	55,870	28,918	25,175	32,335	74,318	2,218,503
(78)	Large High Load	18,157	20,943	23,143	23,587	22,278	20,221	16,197	14,081	13,180	13,048	13,424	14,350	212,608
(79)	Large High Load- Transport	77,177	90,458	100,819	103,659	97,456	87,626	69,037	59,653	56,230	55,592	57,297	62,361	917,366
(80)	XL Low Load	5,623	8,689	11,051	11,439	10,137	7,856	3,600	1,400	310	204	408	1,678	62,393
(81)	XL Low Load-Transport	113,890	170,009	212,968	220,021	196,014	154,462	79,041	40,206	26,124	24,028	27,948	50,077	1,314,786
(82)	XL High Load	11,272	11,153	11,069	11,090	11,109	11,184	11,264	11,292	11,399	11,404	11,569	11,354	135,159
(83)	XL High Load-Transport	559,258	595,491	624,748	632,475	612,116	586,288	537,653	511,688	517,532	515,764	525,931	532,876	6,751,820
(84)	Total	3,595,780	5,204,705	6,462,879	6,693,358	6,014,333	4,819,862	2,658,692	1,548,422	1,168,604	1,114,668	1,222,260	1,830,237	42,333,799
(85)	HLF	735,954	815,078	877,502	891,892	852,202	794,456	686,333	629,816	623,827	620,156	634,564	657,546	8,819,327
(86)	LLF	2,859,825	4,389,626	5,585,377	5,801,466	5,162,131	4,025,405	1,972,359	918,606	544,777	494,512	587,695	1,172,690	33,514,471

Source: Forecast per Ted Poe

REDACTED

Attachment AEL-2
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Attachment AEL-2
Annual GCR Reconciliation Filing

National Grid
Rhode Island - Gas

Schedule 1
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Deferred Gas Cost Balances

Line No.	Description	Reference	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Actual	Sep Actual	Oct Actual	Nov Actual	Dec Actual	Jan Actual	Feb Actual	Mar Actual	Apr-Mar
1	# of Days in Month		30	31	30	31	31	30	31	30	31	31	29	31	**366**
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
2	I. Fixed Cost Deferred														
		Dkt 4576, Sch. AEL-2, pg.													
3	Beginning Under/(Over) Recovery	1, line 17, col. m	($16,586,201)	($17,196,199)	($15,222,687)	($14,704,342)	($11,801,166)	($9,116,530)	($10,511,896)	($7,729,865)	($6,610,561)	($8,875,107)	($10,329,090)	($12,878,739)	($16,586,201)
4															
5	Supply Fixed Costs (net of cap rel)	Sch. 2, line 35	$3,639,523	$3,922,456	$3,906,255	$3,897,003	$3,606,610	$3,889,815	$3,854,414	$3,748,291	$3,521,947	$3,524,390	$3,558,029	$3,521,866	$44,590,600
6	LNG Demand to DAC	Dkt 4339	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
7	Supply Related LNG O & M	Dkt 4323	$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
8	NGPMP Credits		($83,333)	($83,333)	($2,279,922)	($83,333)	($83,333)	($4,468,775)	($83,333)	($783,333)	($2,497,654)	($783,333)	($783,333)	($277,513)	($12,290,531)
9	Working Capital	Sch. 4, line 15	$20,241	$21,870	$21,776	$21,723	$20,051	$21,682	$21,478	$20,867	$19,564	$19,578	$19,771	$19,563	$248,163
10	Total Supply Fixed Costs	sum[(5):(9)]	$3,500,330	$3,784,892	$1,572,008	$3,759,292	$3,467,227	($633,379)	$3,716,458	$2,909,723	$967,756	$2,684,534	$2,718,367	$3,187,816	$31,635,024
11	Supply Fixed - Revenue	Sch. 3, line 13	$4,092,983	$1,794,180	$1,038,298	$842,054	$771,494	$751,908	$924,749	$1,724,573	$3,223,290	$4,126,326	$5,254,232	$4,531,428	$29,075,514
12	Monthly Under/(Over) Recovery	(10) - (11)	($592,653)	$1,990,712	$533,710	$2,917,238	$2,695,734	($1,385,287)	$2,791,709	$1,185,151	($2,255,534)	($1,441,792)	($2,535,865)	($1,343,612)	$2,559,509
13	Prelim. Ending Under/(Over) Recovery	(3) + (12)	($17,178,854)	($15,205,487)	($14,688,977)	($11,787,104)	($9,105,433)	($10,501,818)	($7,720,187)	($6,544,715)	($8,866,095)	($10,316,898)	($12,864,955)	($14,222,351)	($14,026,692)
14	Month's Average Balance	[(3) + (13)] / 2	($16,882,528)	($16,200,843)	($14,955,832)	($13,245,723)	($10,453,299)	($9,809,174)	($9,116,041)	($7,137,290)	($7,738,328)	($9,596,003)	($11,597,023)	($13,550,545)	
15	Interest Rate (BOA Prime minus 200 bps)		1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.38%	1.50%	1.50%	1.50%	
16	Interest Applied	[(14) * (15)] / 365 * (1)	($17,345)	($17,200)	($15,366)	($14,062)	($11,098)	($10,078)	($9,678)	($7,313)	($9,012)	($12,192)	($13,783)	($17,216)	($154,342)
17	Marketer Reconcilation	Dkt 4576	$0	$0	$0	$0	$0	$0	$0	($58,533)	$0	$0	$0	$0	($58,533)
18	Fixed Ending Under/(Over) Recovery	(13) + (16) + (17)	($17,196,199)	($15,222,687)	($14,704,342)	($11,801,166)	($9,116,530)	($10,511,896)	($7,729,865)	($6,610,561)	($8,875,107)	($10,329,090)	($12,878,739)	($14,239,567)	($14,239,567)
19	II. Variable Cost Deferred														
		Dkt 4576, Sch. AEL-2, pg.													
20	Beginning Under/(Over) Recovery	1, line 34, col. m	$38,999,966	$25,699,657	$20,892,063	$18,688,869	$17,196,988	$16,095,772	$14,971,219	$14,821,207	$15,087,445	$16,925,969	$21,441,872	$21,975,898	$38,999,966
21															
22	Variable Supply Costs	Sch. 2, line 81	$6,879,185	$3,813,569	$2,449,655	$2,087,361	$2,049,122	$1,950,787	$3,798,406	$7,164,301	$13,003,521	$18,939,058	$18,793,285	$11,145,605	$92,073,855
23	Supply Related LNG to DAC	Dkt 4339	$0	$0	$0	$0	$0	$0	$0	($11,809)	($95)	($95)	($231,803)	($1,967)	($245,769)
24	Supply Related LNG O & M	Dkt 4323	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$572,694
25	Inventory Financing - LNG	Sch. 5, line 22	$13,336	$14,270	$17,352	$20,776	$24,194	$27,190	$29,848	$30,581	$29,688	$24,819	$16,443	$17,034	$265,531
26	Inventory Financing - UG	Sch. 5, line 12	$56,504	$67,668	$76,291	$84,861	$93,033	$101,117	$106,842	$101,791	$96,132	$76,679	$63,146	$54,296	$978,360
27	Working Capital	Sch. 4, line 30	$39,608	$21,957	$14,104	$12,018	$11,798	$11,232	$21,870	$41,181	$74,869	$109,043	$106,870	$64,161	$528,710
28	Total Supply Variable Costs	sum[(22):(27)]	$7,036,357	$3,965,188	$2,605,126	$2,252,741	$2,225,871	$2,138,051	$4,004,690	$7,373,771	$13,251,839	$19,197,227	$18,795,665	$11,326,854	$94,173,381
29	Supply Variable - Revenue	Sch. 3, line 30	$20,369,885	$8,797,501	$4,828,643	$3,763,661	$3,344,750	$3,278,555	$4,170,508	$7,122,847	$11,516,237	$14,705,682	$18,287,425	$15,891,138	$116,076,831
30	Monthly Under/(Over) Recovery	(28) - (29)	($13,333,528)	($4,832,313)	($2,223,516)	($1,510,920)	($1,118,879)	($1,140,504)	($165,818)	$250,924	$1,735,602	$4,491,545	$508,240	($4,564,284)	($21,903,450)
31	Prelim. Ending Under/(Over) Recovery	(20) + (30)	$25,666,438	$20,867,344	$18,668,547	$17,177,949	$16,078,109	$14,955,268	$14,805,401	$15,072,131	$16,823,048	$21,417,514	$21,950,112	$17,411,614	$17,096,516
32	Month's Average Balance	[(20) + (31)] / 2	$32,333,202	$23,283,501	$19,780,305	$17,933,409	$16,637,549	$15,525,520	$14,888,310	$14,946,669	$15,955,247	$19,171,742	$21,695,992	$19,693,756	
33	Interest Rate (BOA Prime minus 200 bps)		1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.38%	1.50%	1.50%	1.50%	
34	Interest Applied	[(32) * (33)] / 365 * (1)	$33,219	$24,719	$20,322	$19,039	$17,663	$15,951	$15,806	$15,314	$18,582	$24,358	$25,786	$25,021	$255,780
35	Gas Procurement Incentive/(penalty)		$0	$0	$0	$0	$0	$0	$0	$0	$84,340	$0	$0	$0	$84,340
36	Variable Ending Under/(Over) Recovery	(31) + (34) + (35)	$25,699,657	$20,892,063	$18,688,869	$17,196,988	$16,095,772	$14,971,219	$14,821,207	$15,087,445	$16,925,969	$21,441,872	$21,975,898	$17,436,635	$17,436,635
37	**GCR Deferred Summary**														
38	Beginning Under/(Over) Recovery	(3) + (20)	$22,413,764	$8,503,458	$5,669,376	$3,984,527	$5,395,822	$6,979,242	$4,459,323	$7,091,342	$8,476,885	$8,050,863	$11,112,782	$9,097,160	$22,413,764
39	Gas Costs	sum[(4):(7),(17),(22):(24)]	$10,490,332	$7,707,649	$6,327,534	$5,955,988	$5,627,356	$5,812,226	$7,624,444	$10,813,873	$16,496,997	$22,434,976	$22,091,135	$14,637,128	$136,019,638
40	Inventory Finance	(25) + (26)	$69,840	$81,938	$93,643	$105,637	$117,227	$128,307	$136,690	$132,373	$125,820	$101,497	$79,589	$71,331	$1,243,891
41	Working Capital	(9) + (27)	$59,848	$43,827	$35,881	$33,741	$31,849	$32,914	$43,348	$62,048	$94,432	$128,621	$126,641	$83,724	$776,873
42	NGPMP Credits	(8)	($83,333)	($83,333)	($2,279,922)	($83,333)	($83,333)	($4,468,775)	($83,333)	($783,333)	($2,497,654)	($783,333)	($783,333)	($277,513)	($12,290,531)
43	Total Costs	sum[(39):(42)]	$10,536,687	$7,750,080	$4,177,135	$6,012,034	$5,693,098	$1,504,671	$7,721,148	$10,224,961	$14,219,595	$21,881,761	$21,514,032	$14,514,670	$125,749,872
44	Revenue	(11) + (29)	$24,462,868	$10,591,681	$5,866,941	$4,605,715	$4,116,243	$4,030,463	$5,095,257	$8,847,420	$14,739,527	$18,832,008	$23,541,657	$20,422,567	$145,152,346
45	Monthly Under/(Over) Recovery	(43) - (44)	($13,926,181)	($2,841,601)	($1,689,806)	$1,406,318	$1,576,855	($2,525,792)	$2,625,891	$1,377,541	($519,932)	$3,049,753	($2,027,625)	($5,907,897)	($19,402,474)
46	Prelim. Ending Under/(Over) Recovery	(38) + (45)	$8,487,584	$5,661,857	$3,979,570	$5,390,845	$6,972,677	$4,453,450	$7,085,214	$8,468,883	$7,956,953	$11,100,616	$9,085,157	$3,189,263	$3,011,290
47	Month's Average Balance	[(38) + (46)] / 2	$15,450,674	$7,082,657	$4,824,473	$4,687,686	$6,184,249	$5,716,346	$5,772,269	$7,780,113	$8,216,919	$9,575,739	$10,098,969	$6,143,211	
48	Interest Rate (BOA Prime minus 200 bps)		1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.38%	1.50%	1.50%	1.50%	
49	Interest Applied	(16) + (34)	$15,874	$7,519	$4,957	$4,977	$6,565	$5,873	$6,128	$8,001	$9,570	$12,166	$12,003	$7,805	$101,438
50	Gas Purchase Plan Incentives/(Penalties)	(35)	$0	$0	$0	$0	$0	$0	$0	$0	$84,340	$0	$0	$0	$84,340
51															
52	**Ending Under/(Over) Recovery W/ Interes**	(46) + (49) + (50)	**$8,503,458**	**$5,669,376**	**$3,984,527**	**$5,395,822**	**$6,979,242**	**$4,459,323**	**$7,091,342**	**$8,476,885**	**$8,050,863**	**$11,112,782**	**$9,097,160**	**$3,197,068**	$3,197,068

REDACTED

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4647
Attachment AEL-2
Redacted
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Supply Estimate and Actuals for Filing

Line No.	Description	Reference	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 (m)
1	**SUPPLY FIXED COSTS - Pipeline Delivery**														
2	Algonquin (includes East to West, Hubline, AMA credits		$860,386	$860,386	$860,386	$860,386	$860,386	$860,386	$860,386	$784,089	$836,387	$829,995	$836,694	$836,762	$10,146,629
3	TETCO/Texas Eastern		$724,878	$761,985	$724,892	$724,885	$722,250	$723,058	$723,050	$722,017	$722,257	$722,264	$722,264	$720,185	$8,713,986
4	Tennessee		$1,002,992	$1,017,763	$1,048,710	$1,067,794	$775,741	$1,048,712	$1,048,711	$930,608	$976,328	$976,328	$976,328	$976,328	$11,846,342
5	NETNE		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Iroquois		$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$80,115
7	Union		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Transcanada		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Dominion		($28,714)	($28,714)	($28,714)	($32,952)	($28,714)	($28,714)	($28,714)	$2,276	$2,276	$2,276	$2,276	$2,276	($193,859)
10	Transco		$4,869	$5,032	$4,869	$5,032	$5,032	$4,869	$5,032	$4,869	$5,032	$5,032	$4,707	$5,032	$59,406
11	National Fuel		$4	$9,334	$4,667	$4,667	$4,667	$4,667	$4,667	$4,667	$4,574	$4,480	$4,574	$4,574	$55,543
12	Columbia		$282,447	$300,702	$283,519	$283,519	$283,519	$283,519	$300,833	$340,803	$289,238	$289,797	$308,551	$304,135	$3,550,581
13	Alberta Northeast		$345	$391	$373	$433	$433	$423	$360	$371	$342	$387	$327	$348	$4,533
14	Emera Energy		($21,500)	($21,500)	($21,500)	($21,500)	($21,500)	($21,500)	($21,500)	$0	$0	$0	$0	$0	($150,500)
15	Cargill Ltd.		$12,823	$14,737	$15,474	$12,578	$13,616	$15,120	$11,418	$966	$0	$0	$0	$0	$96,732
16	Westerly Lateral		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	Less Credits from Mkter Releases		($788,231)	($586,715)	($575,515)	($596,794)	($597,573)	($588,952)	($639,303)	($639,181)	($657,699)	($674,773)	($644,061)	($674,910)	($7,663,706)
18	**Supply Fixed - Supplier**														
19	Distrigas FCS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**STORAGE FIXED COSTS - Facilities**														
21	Texas Eastern		$85,768	$85,636	$85,639	$85,500	$85,299	$84,771	$85,511	$85,022	$84,962	$85,011	$84,964	$84,726	$1,022,809
22	Dominion		$82,967	$82,967	$82,967	$82,967	$82,967	$82,967	$82,967	$82,949	$82,949	$82,949	$82,949	$82,949	$995,518
23	Tennessee		$49,804	$49,804	$49,804	$49,804	$49,804	$49,804	$49,804	$42,271	$48,337	$50,950	$48,337	$48,337	$586,860
24	Columbia		$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$10,203	$20,608	$3,477	$9,694	$9,694	$9,694	$121,534
25	Keyspan LNG Tank Lease Paymen		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	**STORAGE FIXED COSTS - Delivery**														
27	Algonquin		$210,918	$210,918	$210,918	$210,918	$210,918	$210,918	$210,918	$215,436	$215,436	$215,436	$215,436	$215,436	$2,553,602
28	TETCO		$87,499	$87,499	$87,499	$87,499	$87,499	$87,499	$87,499	$87,599	$87,599	$87,599	$87,599	$87,599	$1,050,486
29	Tennessee		$90,782	$90,782	$90,782	$90,782	$90,782	$90,782	$90,782	$91,219	$91,219	$91,219	$91,219	$91,219	$1,091,566
30	Dominion		$30,946	$30,946	$30,946	$30,946	$30,946	$30,946	$30,946	$30,695	$30,695	$30,695	$30,695	$30,695	$370,098
31	Columbia		$15,010	$15,010	$15,010	$15,010	$15,010	$15,010	$15,010	$15,171	$15,171	$15,171	$15,171	$15,171	$180,927
32	Distrigas FLS call payment		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	BP Energy Company														
34	Emera Energy														
35	**TOTAL FIXED COSTS**	sum[(2):(34)]	$3,639,523	$3,922,456	$3,906,255	$3,897,003	$3,606,610	$3,889,815	$3,854,414	$3,748,291	$3,521,947	$3,524,390	$3,558,029	$3,521,866	$44,590,600

REDACTED

Supply Estimate and Actuals for Filing

Line No.	Description	Reference	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 (m)
36	**VARIABLE SUPPLY COSTS (Includes Injections)**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Tennessee (Includes ANE and Niagara														
38	TETCO (Includes B&W)														
39	M3 Delivered														
40	Maumee														
41	Broadrun Col														
42	Columbia Eagle and Downingtown														
43	TETCO M2														
44	Dominion to TETCO FTS														
45	Transco Zone 3														
46	DistriGas FCS														
47	Hubline														
48	Total Pipeline Commodity Charges	sum[(37):(47)]	$3,956,859	$1,331,586	$1,034,504	$784,238	$757,037	$470,995	$1,886,474	$2,817,640	$5,590,786	$9,087,594	$8,210,167	$3,697,752	$39,625,632
49	Hedging Settlements and Amortization		$2,388,865	$1,523,483	$727,053	$651,262	$534,652	$656,556	$1,064,231	$2,827,644	$5,622,697	$5,960,230	$6,252,860	$5,737,029	$33,946,561
50	Hedging Contracts - Commission & Other Fees		$1,182	$1,348	$606	$435	$802	$652	$671	$168,614	$804,160	$870,881	$804,374	$703,868	$3,357,591
51	Hedging Contracts - Net Carry of Collatera		$10,779	$12,212	$7,767	$9,513	$11,818	$11,409	$12,259	$14,953	$14,864	$16,589	$16,609	$15,334	$154,107
52	Refunds		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
53	Less: Costs of Injections		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
54	**TOTAL VARIABLE SUPPLY COSTS**	sum[(48):(53)]	$6,357,685	$2,868,630	$1,769,930	$1,445,448	$1,304,308	$1,139,612	$2,963,634	$5,828,851	$12,032,506	$15,935,295	$15,284,010	$10,153,983	$77,083,891
55	Underground Storage		$363,616	$101,983	$126,608	$98,426	$177,278	$219,245	$219,188	$677,039	$398,548	$1,689,439	$1,137,575	$657,975	$5,866,920
56	LNG Withdrawals and Trucking		$95,504	$109,426	$103,370	$129,000	$112,980	$122,273	$108,465	$107,834	$84,350	$895,005	$1,422,827	$143,293	$3,434,327
57	Storage Delivery Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
58	**TOTAL VARIABLE STORAGE COSTS**	sum[(55):(57)]	$459,120	$211,410	$229,978	$227,426	$290,258	$341,518	$327,653	$784,873	$482,898	$2,584,444	$2,560,402	$801,269	$9,301,247
59	**TOTAL VARIABLE COSTS**	(54) + (58)	$6,816,804	$3,080,039	$1,999,908	$1,672,874	$1,594,566	$1,481,130	$3,291,287	$6,613,724	$12,515,404	$18,519,738	$17,844,412	$10,955,252	$86,385,138
60	**TOTAL SUPPLY COSTS**	(35) + (59)	$10,456,327	$7,002,496	$5,906,163	$5,569,877	$5,201,176	$5,370,944	$7,145,701	$10,362,015	$16,037,351	$22,044,129	$21,402,441	$14,477,118	$130,975,738
61	**Storage Costs for FT-2 Calculation**														
62	**Storage Fixed Costs - Facilities**		$391,973	$391,841	$391,844	$391,705	$391,504	$390,976	$392,225	$394,591	$383,465	$392,345	$389,684	$389,446	$4,691,601
63	**Storage Fixed Costs - Deliveries**		$1,138,280	$1,138,245	$1,138,280	$1,138,280	$1,138,280	$1,138,280	$1,138,280	$1,305,744	$1,062,866	$1,062,869	$1,062,869	$1,062,869	$13,525,140
64	**sub-total Storage Costs**	sum[(62):(63)]	$1,530,253	$1,530,086	$1,530,124	$1,529,985	$1,529,784	$1,529,256	$1,530,505	$1,700,335	$1,446,331	$1,455,214	$1,452,553	$1,452,315	$18,216,741
65	**LNG Demand to DAC**		($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
66	**Inventory Financing**		$69,840	$81,938	$93,643	$105,637	$117,227	$128,307	$136,690	$132,373	$125,820	$101,497	$79,589	$71,331	$1,243,891
67	**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
68	**Working Capital Requirement**		$20,241	$21,870	$21,776	$21,723	$20,051	$21,682	$21,478	$20,867	$19,564	$19,578	$19,771	$19,563	$248,163
69	**Total FT-2 Storage Fixed Costs**	sum[(64):(68)]	$1,544,233	$1,557,793	$1,569,442	$1,581,244	$1,590,962	$1,603,144	$1,612,572	$1,777,474	$1,515,614	$1,500,188	$1,475,813	$1,467,108	$18,795,587
70	**System Storage MDQ (Dth)**		179,530	182,826	182,581	183,139	187,316	187,859	190,113	193,596	169,835	169,667	175,833	177,366	2,179,660
71	**FT-2 Storage Cost per MDQ (Dth)**	(69) / (70)	$8.6015	$8.5207	$8.5959	$8.6341	$8.4934	$8.5338	$8.4822	$9.1813	$8.9240	$8.8420	$8.3932	$8.2717	$8.6232
72	Pipeline Variable	(59)	$6,816,804	$3,080,039	$1,999,908	$1,672,874	$1,594,566	$1,481,130	$3,291,287	$6,613,724	$12,515,404	$18,519,738	$17,844,412	$10,955,252	$86,385,138
73	Less Non-firm Gas Costs		($78,627)	($76,517)	($33,023)	($5,698)	($11,298)	($24,192)	($23,360)	($59,229)	($117,023)	($150,820)	($14,806)	($70,277)	($664,870)
74	Less Company Use		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
75	Less Manchester St Balancing		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
76	Plus Cashout		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
77	Less Mkter W/drawals/Injections		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
78	Mkter Over-takes/Undertakes		($231,773)	$395,251	$67,294	$15,338	$23,820	$50,884	$98,770	$143,247	$113,464	$84,751	$460,356	($184,741)	$1,036,660
79	Plus Pipeline Srchg/Credit		$429,410	$420,924	$434,954	$421,819	$442,384	$442,965	$431,520	$449,140	$490,398	$506,399	$505,394	$472,592	$5,447,900
80	Less Mkter FT-2 Daily weather true-up		($56,630)	($6,129)	($19,478)	($16,971)	($350)	$0	$189	$17,419	$1,278	($21,010)	($2,071)	($27,221)	($130,973)
81	**TOTAL FIRM COMMODITY COSTS**	sum[(72):(80)]	$6,879,185	$3,813,569	$2,449,655	$2,087,361	$2,049,122	$1,950,787	$3,798,406	$7,164,301	$13,003,521	$18,939,058	$18,793,285	$11,145,605	$92,073,855

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GCR Revenue

Line No.	Description	Reference	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 (m)
1	**I. Fixed Cost Revenue --**														
2	(a) Low Load dth	Sch. 6, lines sum[(24:28), 30]	3,441,723	1,494,047	776,700	606,897	539,088	526,359	680,129	1,316,256	2,596,037	3,373,716	4,195,398	3,658,182	23,204,532
3	Fixed Cost Factor	(4) / (2)	$1.0485	$1.0480	$1.0478	$1.0503	$1.0566	$1.0476	$1.0482	$1.1375	$1.1494	$1.1417	$1.1416	$1.1432	
4	Low Load Revenue		$3,608,550	$1,565,727	$813,788	$637,411	$569,606	$551,416	$712,895	$1,497,286	$2,983,958	$3,851,664	$4,789,263	$4,182,118	$25,763,683
5	(b) High Load dth	Sch. 6, lines sum (22, 23, 29, 31)	169,715	87,872	84,125	58,324	52,614	50,484	61,263	72,391	103,495	108,116	122,499	100,798	1,071,696
6	Fixed Cost Factor	(7) / (5)	$0.8783	$0.8831	$0.8779	$0.8753	$0.8754	$0.8778	$0.8757	$0.9169	$0.8845	$0.8805	$0.8799	$0.8542	
7	High Load Revenue		$149,060	$77,596	$73,856	$51,053	$46,057	$44,314	$53,646	$66,375	$91,540	$95,197	$107,785	$86,106	$942,585
8	sub-total throughput Dth	(2) + (5)	3,611,438	1,581,919	860,825	665,221	591,702	576,843	741,392	1,388,648	2,699,532	3,481,832	4,317,898	3,758,980	24,276,228
9	FT-2 Storage Revenue from marketers		$335,373	$150,856	$150,654	$151,115	$154,562	$155,009	$156,869	$159,744	$146,055	$178,446	$356,309	$261,170	$2,356,162
10	Manchester Steet Volumes (dth)	Monthly Meter Use	0	0	0	2,288	1,172	1,080	1,237	991	1,473	863	742	1,725	11,570
11	Fixed cost factor (dth)	Inherent in approved GCR	$0.0000	$0.0000	$0.0000	$1.0822	$1.0822	$1.0822	$1.0822	$1.1796	$1.1796	$1.1796	$1.1796	$1.1796	
12	Manchester Street Revenue	(10) * (11)	$0	$0	$0	$2,476	$1,268	$1,168	$1,339	$1,169	$1,737	$1,018	$875	$2,035	$13,085
13	**TOTAL Fixed Revenue**	(4) + (7) + (9)	**$4,092,983**	**$1,794,180**	**$1,038,298**	**$842,054**	**$771,494**	**$751,908**	**$924,749**	**$1,724,573**	**$3,223,290**	**$4,126,326**	**$5,254,232**	**$4,531,428**	**$29,075,514**
14	**II. Variable Cost Revenue --**														
15	(a) Firm Sales dth	(8)	3,611,438	1,581,919	860,825	665,221	591,702	576,843	741,392	1,388,648	2,699,532	3,481,832	4,317,898	3,758,980	24,276,228
16	Variable Supply Cost Factor	(17) / (15)	$5.6098	$5.6092	$5.6071	$5.6178	$5.6486	$5.6061	$5.6077	$5.1025	$4.2399	$4.2116	$4.2111	$4.2138	
17	Variable Supply Revenue		20,259,475	8,873,255	4,826,720	3,737,046	3,342,306	3,233,827	4,157,476	7,085,565	11,445,726	14,664,054	18,182,980	15,839,493	$115,647,922
18	(b) TSS Sales dth	Sch. 6, line 20	37,964	17,740	14,933	9,328	8,662	5,281	13,013	17,510	26,312	29,803	35,617	33,863	250,027
19	TSS Surcharge Factor	Company's website	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
20	TSS Surcharge Revenue	(18) * (19)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	(c) Default Sales dth	Sch. 6, line 60	7,386	195	261	835	(1,362)	5,248	165	4,805	8,633	5,044	8,588	5,343	45,141
22	Variable Supply Cost Factor	(23) / (21)	$11.7007	($317.6906)	$6.6502	$6.6528	$6.6514	$6.6527	$6.6565	$6.6524	$6.3981	$7.5081	$10.4535	$2.4681	
23	Variable Supply Revenue		$86,420	($61,981)	$1,735	$5,554	($9,057)	$34,910	$1,099	$31,962	$55,235	$37,872	$89,778	$13,188	$286,715
24	(d) Peaking Gas Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	(e) Deferred Responsibility		$23,989	($13,773)	$188	$7,816	$4,716	$3,568	$4,771	$1,010	$8,868	$0	$11,438	$30,951	$83,543
26	(f) FT-1 Storage and Peaking		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
27	(g) Manchester Steet Volumes (dth)	Monthly Meter Use	0	0	0	2,288	1,172	1,080	1,237	991	1,473	863	742	1,725	11,570
28	Variable Supply Cost Factor (dth	Inherent in approved GCR	$0.0000	$0.0000	$0.0000	$5.7894	$5.7894	$5.7894	$5.7894	$4.3514	$4.3514	$4.3514	$4.3514	$4.3514	
29	Manchester Street Revenue	(27) * (28)	$0	$0	$0	$13,244	$6,785	$6,250	$7,161	$4,310	$6,408	$3,756	$3,229	$7,506	$58,651
30	**TOTAL Variable Revenue**	(17)+(20)+(23)+(24)+(25)+(26)+(29)	**$20,369,885**	**$8,797,501**	**$4,828,643**	**$3,763,661**	**$3,344,750**	**$3,278,555**	**$4,170,508**	**$7,122,847**	**$11,516,237**	**$14,705,682**	**$18,287,425**	**$15,891,138**	**$116,076,831**
31	**Total Gas Cost Revenue (w/o FT-2**	(13) + (30)	**$24,462,868**	**$10,591,681**	**$5,866,941**	**$4,605,715**	**$4,116,243**	**$4,030,463**	**$5,095,257**	**$8,847,420**	**$14,739,527**	**$18,832,008**	**$23,541,657**	**$20,422,567**	**$145,152,346**

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 c
associated with heater gas used at Manchester St. Station.

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Working Capital

Line No.	Description	Reference	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 (m)
1	**Supply Fixed Costs**	Sch. 1, line 5	$3,639,523	$3,922,456	$3,906,255	$3,897,003	$3,606,610	$3,889,815	$3,854,414	$3,748,291	$3,521,947	$3,524,390	$3,558,029	$3,521,866	$44,590,600
2	Less: LNG Demand to DAC	Sch. 1, line 6	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
3	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Total Adjustments	(2) + (3)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
5	Allowable Working Capital Costs	(1) + (4)	$3,515,457	$3,798,390	$3,782,189	$3,772,938	$3,482,544	$3,765,749	$3,730,348	$3,624,225	$3,397,881	$3,400,325	$3,433,964	$3,397,800	$43,101,810
6	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
7	Working Capital Requirement	[(5) * (6)] / 365	$207,171	$223,845	$222,890	$222,345	$205,232	$221,921	$219,835	$213,581	$200,242	$200,386	$202,369	$200,237	
8	Cost of Capital	Dkt 4339	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
9	Return on Working Capital Requirement	(7) * (8)	$15,020	$16,229	$16,160	$16,120	$14,879	$16,089	$15,938	$15,485	$14,518	$14,528	$14,672	$14,517	
10	Weighted Cost of Debt	Dkt 4339	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
11	Interest Expense	(7) * (10)	$5,324	$5,753	$5,728	$5,714	$5,274	$5,703	$5,650	$5,489	$5,146	$5,150	$5,201	$5,146	
12	Taxable Income	(9) - (11)	$9,696	$10,476	$10,431	$10,406	$9,605	$10,386	$10,288	$9,996	$9,371	$9,378	$9,471	$9,371	
13	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	
14	Return and Tax Requirement	(12) / (13)	$14,916	$16,117	$16,048	$16,009	$14,777	$15,978	$15,828	$15,378	$14,417	$14,428	$14,571	$14,417	
15	**Supply Fixed Working Capital Requirement**	(11) + (14)	$20,241	$21,870	$21,776	$21,723	$20,051	$21,682	$21,478	$20,867	$19,564	$19,578	$19,771	$19,563	$248,163
16	**Supply Variable Costs**	Sch. 1, line 22	$6,879,185	$3,813,569	$2,449,655	$2,087,361	$2,049,122	$1,950,787	$3,798,406	$7,164,301	$13,003,521	$18,939,058	$18,793,285	$11,145,605	$92,073,855
17	Less: Balancing Related LNG Commodity (to DAC)	Sch. 1, line 23	$0	$0	$0	$0	$0	$0	$0	($11,809)	($95)	($95)	($231,803)	($1,967)	($245,769)
18	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Total Adjustments	(17) + (18)	$0	$0	$0	$0	$0	$0	$0	($11,809)	($95)	($95)	($231,803)	($1,967)	($245,769)
20	Allowable Working Capital Costs	(16) + (19)	$6,879,185	$3,813,569	$2,449,655	$2,087,361	$2,049,122	$1,950,787	$3,798,406	$7,152,492	$13,003,426	$18,938,962	$18,561,482	$11,143,638	$91,828,086
21	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
22	Working Capital Requirement	[(20) * (21)] / 365	$405,401	$224,739	$144,362	$123,011	$120,758	$114,963	$223,846	$421,507	$766,311	$1,116,102	$1,093,856	$656,711	
23	Cost of Capital	Dkt 4339	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
24	Return on Working Capital Requirement	(22) * (23)	$29,392	$16,294	$10,466	$8,918	$8,755	$8,335	$16,229	$30,559	$55,558	$80,917	$79,305	$47,612	
25	Weighted Cost of Debt	Dkt 4339	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
26	Interest Expense	(22) * (25)	$10,419	$5,776	$3,710	$3,161	$3,103	$2,955	$5,753	$10,833	$19,694	$28,684	$28,112	$16,877	
27	Taxable Income	(24) - (26)	$18,973	$10,518	$6,756	$5,757	$5,651	$5,380	$10,476	$19,727	$35,863	$52,234	$51,192	$30,734	
28	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	
29	Return and Tax Requirement	(27) / (28)	$29,189	$16,181	$10,394	$8,857	$8,695	$8,277	$16,117	$30,349	$55,174	$80,359	$78,758	$47,283	
30	**Supply Variable Working Capital Requirement**	(26) + (29)	$39,608	$21,957	$14,104	$12,018	$11,798	$11,232	$21,870	$41,181	$74,869	$109,043	$106,870	$64,161	$528,710

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Inventory Finance

Line No.	Description	Reference	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 (m)
1	**Storage Inventory Balance**		$6,375,332	$7,148,665	$7,792,252	$8,425,443	$9,046,406	$9,505,896	$9,777,034	$9,323,989	$9,431,867	$7,912,417	$7,053,287	$6,668,946	
2	Monthly Storage Deferral/Amortization		$564,746	$1,162,656	$1,578,183	$1,997,601	$2,380,359	$2,913,810	$3,345,838	$3,178,547	$2,375,546	$1,505,628	$702,627	$1	
3	**Subtotal**	(1) + (2)	**$6,940,078**	**$8,311,321**	**$9,370,435**	**$10,423,044**	**$11,426,765**	**$12,419,706**	**$13,122,872**	**$12,502,536**	**$11,807,413**	**$9,418,045**	**$7,755,914**	**$6,668,947**	
4	Cost of Capital	Dkt 4339	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
5	Return on Working Capital Requirement	(3) * (4)	$503,156	$602,571	$679,357	$755,671	$828,440	$900,429	$951,408	$906,434	$856,037	$682,808	$562,304	$483,499	$8,712,113
6	Weighted Cost of Debt	Dkt 4339	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
7	Interest Charges Financed	(3) * (6)	$178,360	$213,601	$240,820	$267,872	$293,668	$319,186	$337,258	$321,315	$303,451	$242,044	$199,327	$171,392	$3,088,294
8	Taxable Income	(5) - (7)	$324,796	$388,970	$438,536	$487,798	$534,773	$581,242	$614,150	$585,119	$552,587	$440,765	$362,977	$312,107	
9	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	
10	Return and Tax Requirement	(8) / (9)	$499,686	$598,415	$674,671	$750,459	$822,727	$894,219	$944,847	$900,183	$850,134	$678,099	$558,426	$480,164	$8,652,030
11	Working Capital Requirement	(7) + (10)	$678,046	$812,016	$915,491	$1,018,331	$1,116,395	$1,213,405	$1,282,105	$1,221,498	$1,153,584	$920,143	$757,753	$651,556	$11,740,323
12	Monthly Average	(11) / 12	$56,504	$67,668	$76,291	$84,861	$93,033	$101,117	$106,842	$101,791	$96,132	$76,679	$63,146	$54,296	$978,360
13	**LNG Inventory Balance**		$1,638,036	$1,752,681	$2,131,212	$2,551,825	$2,971,655	$3,339,634	$3,666,037	$3,756,170	$3,646,413	$3,048,366	$2,019,560	$2,092,259	
14	Cost of Capital	Dkt 4339	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
15	Return on Working Capital Requirement	(13) * (14)	$118,758	$127,069	$154,513	$185,007	$215,445	$242,123	$265,788	$272,322	$264,365	$221,007	$146,418	$151,689	$2,364,504
16	Weighted Cost of Debt	Dkt 4339	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	
17	Interest Charges Financed	(13) * (16)	$42,098	$45,044	$54,772	$65,582	$76,372	$85,829	$94,217	$96,534	$93,713	$78,343	$51,903	$53,771	$838,176
18	Taxable Income	(15) - (17)	$76,660	$82,025	$99,741	$119,425	$139,073	$156,295	$171,571	$175,789	$170,652	$142,664	$94,515	$97,918	
19	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	
20	Return and Tax Requirement	(18) / (19)	$117,939	$126,193	$153,447	$183,731	$213,959	$240,454	$263,955	$270,444	$262,542	$219,482	$145,408	$150,643	$2,348,197
21	Working Capital Requirement	(17) + (20)	$160,036	$171,237	$208,219	$249,313	$290,331	$326,282	$358,172	$366,978	$356,255	$297,825	$197,311	$204,414	$3,186,373
22	Monthly Average	(21) / 12	$13,336	$14,270	$17,352	$20,776	$24,194	$27,190	$29,848	$30,581	$29,688	$24,819	$16,443	$17,034	$265,531
23	TOTAL GCR Inventory Financing Costs	(12) + (22)	**$69,840**	**$81,938**	**$93,643**	**$105,637**	**$117,227**	**$128,307**	**$136,690**	**$132,373**	**$125,820**	**$101,497**	**$79,589**	**$71,331**	**$1,243,891**

REDACTED

Actual Dth Usage for Filing

Line No.	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 (m)
	THROUGHPUT (Dth)													
1	**SALES**													
2	Residential Non-Heating	83,622	45,364	29,503	23,827	21,194	20,827	24,491	37,092	60,224	75,729	89,222	67,317	**578,412**
3	Residential Non-Heating Low Income	4,329	2,015	1,051	787	728	593	828	1,316	2,434	3,160	3,548	2,537	**23,325**
4	Residential Heating	2,298,799	1,005,002	502,341	400,977	346,347	343,276	450,190	894,673	1,774,748	2,309,007	2,862,444	2,537,120	**15,724,923**
5	Residential Heating Low Income	247,469	109,620	61,630	49,907	40,759	40,160	50,642	93,503	177,183	227,988	271,102	173,668	**1,543,630**
6	Small C&I	338,002	125,776	58,890	47,382	43,390	42,914	52,565	103,351	234,087	316,821	424,123	362,345	**2,149,645**
7	Medium C&I	408,835	197,016	114,481	88,610	76,911	82,998	101,609	172,404	312,683	395,600	482,261	433,570	**2,866,977**
8	Large LLF	101,589	45,229	11,989	10,474	25,083	11,388	11,263	32,833	66,156	87,518	113,350	106,251	**623,124**
9	Large HLF	31,088	15,252	19,782	8,379	11,266	11,420	19,984	17,530	18,358	18,187	20,408	17,020	**208,674**
10	Extra Large LLF	12,084	(4,815)	14,341	1,735	(628)	1,821	2,420	3,781	6,963	9,313	9,683	14,539	**71,236**
11	Extra Large HLF	47,657	23,721	31,883	23,815	17,991	16,165	14,386	14,656	20,385	8,705	6,141	10,751	**236,255**
12	**Total Sales**	3,573,474	1,564,179	845,891	655,892	583,040	571,562	728,379	1,371,138	2,673,220	3,452,028	4,282,281	3,725,117	**24,026,201**
13	**TSS**													
14	Small	1,345	378	220	185	192	0	56	30	63	190	273	237	**3,169**
15	Medium	25,222	11,865	10,534	6,483	5,923	3,175	10,365	11,278	16,740	20,111	23,975	22,576	**168,246**
16	Large LLF	8,378	3,976	2,274	1,144	1,112	628	1,018	4,405	7,416	7,166	8,188	7,877	**53,582**
17	Large HLF	2,402	1,277	1,687	1,357	1,310	1,478	1,574	1,797	2,093	2,336	3,181	3,174	**23,666**
18	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	**0**
19	Extra Large HLF	616	245	218	159	125	0	0	0	0	0	0	0	**1,364**
20	**Total TSS**	37,964	17,740	14,933	9,328	8,662	5,281	13,013	17,510	26,312	29,803	35,617	33,863	**250,027**
21	**Sales & TSS THROUGHPUT**													
22	Residential Non-Heating	83,622	45,364	29,503	23,827	21,194	20,827	24,491	37,092	60,224	75,729	89,222	67,317	**578,412**
23	Residential Non-Heating Low Income	4,329	2,015	1,051	787	728	593	828	1,316	2,434	3,160	3,548	2,537	**23,325**
24	Residential Heating	2,298,799	1,005,002	502,341	400,977	346,347	343,276	450,190	894,673	1,774,748	2,309,007	2,862,444	2,537,120	**15,724,923**
25	Residential Heating Low Income	247,469	109,620	61,630	49,907	40,759	40,160	50,642	93,503	177,183	227,988	271,102	173,668	**1,543,630**
26	Small C&I	339,347	126,153	59,110	47,568	43,581	42,914	52,622	103,381	234,149	317,012	424,396	362,582	**2,152,814**
27	Medium C&I	434,057	208,882	125,015	95,093	82,834	86,173	111,974	183,682	329,423	415,711	506,235	456,146	**3,035,223**
28	Large LLF	109,967	49,205	14,263	11,618	26,195	12,016	12,281	37,238	73,573	94,684	121,538	114,128	**676,706**
29	Large HLF	33,491	16,528	21,469	9,736	12,576	12,898	21,558	19,327	20,451	20,523	23,589	20,194	**232,340**
30	Extra Large LLF	12,084	(4,815)	14,341	1,735	(628)	1,821	2,420	3,781	6,963	9,313	9,683	14,539	**71,236**
31	Extra Large HLF	48,274	23,965	32,101	23,974	18,116	16,165	14,386	14,656	20,385	8,705	6,141	10,751	**237,619**
32	**Total Sales & TSS Throughput**	3,611,438	1,581,919	860,825	665,221	591,702	576,843	741,392	1,388,648	2,699,532	3,481,832	4,317,898	3,758,980	**24,276,228**
33	**FT-1 TRANSPORTATION**													
34	FT-1 Medium	75,806	21,313	6,857	21,051	24,285	24,512	24,527	63,644	68,106	75,898	132,048	80,921	**618,967**
35	FT-1 Large LLF	90,860	33,587	33,587	17,758	16,211	11,575	20,511	90,987	108,704	113,907	224,428	122,228	**884,342**
36	FT-1 Large HLF	45,155	24,369	25,331	33,188	26,564	31,062	34,626	42,174	44,422	39,881	66,915	44,249	**457,935**
37	FT-1 Extra Large LLF	112,130	41,421	41,421	3,936	18,237	19,300	26,775	128,795	147,186	149,215	255,433	164,414	**1,108,263**
38	FT-1 Extra Large HLF	595,745	354,609	415,032	428,859	457,334	452,386	408,034	465,126	508,134	512,954	600,196	496,037	**5,694,446**
39	Default	7,386	195	261	835	(1,362)	5,248	165	4,805	8,633	5,044	8,588	5,343	**45,141**
40	**Total FT-1 Transportation**	927,081	475,494	522,488	505,627	541,270	544,083	514,638	795,530	885,185	896,900	1,287,608	913,192	**8,809,094**
41	**FT-2 TRANSPORTATION**													
42	FT-2 Small	7,807	3,208	1,627	1,503	1,431	1,445	1,686	3,168	7,148	11,801	16,262	13,677	**70,764**
43	FT-2 Medium	204,857	107,703	60,396	49,330	46,825	45,603	58,466	101,345	171,161	219,040	264,594	227,758	**1,557,076**
44	FT-2 Large LLF	114,024	62,983	29,165	11,198	13,175	15,590	25,658	65,164	126,421	166,758	196,312	191,012	**1,017,459**
45	FT-2 Large HLF	50,722	35,421	37,616	27,338	31,531	21,841	24,725	30,668	19,443	47,289	51,672	44,457	**422,723**
46	FT-2 Extra Large LLF	8,322	3,613	1,404	1,094	833	435	839	4,340	7,674	9,285	12,583	11,869	**62,291**
47	FT-2 Extra Large HLF	16,367	26,776	17,265	22,552	19,024	37,093	31,609	40,295	44,082	45,454	47,875	50,114	**398,507**
48	**Total FT-2 Transportation**	402,099	239,705	147,473	113,016	112,819	122,007	142,982	244,979	375,929	499,627	589,297	538,887	**3,528,820**
49	**Total THROUGHPUT**													
50	Residential Non-Heating	83,622	45,364	29,503	23,827	21,194	20,827	24,491	37,092	60,224	75,729	89,222	67,317	**578,412**
51	Residential Non-Heating Low Income	4,329	2,015	1,051	787	728	593	828	1,316	2,434	3,160	3,548	2,537	**23,325**
52	Residential Heating	2,298,799	1,005,002	502,341	400,977	346,347	343,276	450,190	894,673	1,774,748	2,309,007	2,862,444	2,537,120	**15,724,923**
53	Residential Heating Low Income	247,469	109,620	61,630	49,907	40,759	40,160	50,642	93,503	177,183	227,988	271,102	173,668	**1,543,630**
54	Small C&I	347,154	129,362	60,737	49,071	45,013	44,359	54,307	106,549	241,297	328,813	440,658	376,259	**2,223,578**
55	Medium C&I	714,720	337,898	192,267	165,473	153,944	156,287	194,967	348,671	568,689	710,649	902,877	764,825	**5,211,266**
56	Large LLF	314,850	145,774	77,015	40,575	55,581	39,181	58,450	193,388	308,698	375,350	542,278	427,367	**2,578,507**
57	Large HLF	129,368	76,319	84,416	70,262	70,672	65,801	80,908	92,168	84,316	107,694	142,175	108,900	**1,112,999**
58	Extra Large LLF	132,536	40,220	57,165	6,765	18,441	21,557	30,034	136,916	161,823	167,814	277,699	190,821	**1,241,790**
59	Extra Large HLF	660,386	405,351	464,398	475,385	494,475	505,645	454,030	520,078	572,601	567,112	654,211	556,902	**6,330,572**
60	Default	7,386	195	261	835	(1,362)	5,248	165	4,805	8,633	5,044	8,588	5,343	**45,141**
61	**Total Throughput**	4,940,618	2,297,118	1,530,785	1,283,863	1,245,791	1,242,933	1,399,012	2,429,157	3,960,645	4,878,358	6,194,802	5,211,058	**36,614,142**

REDACTED

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4647
Attachment AEL-2
Redacted
Page 7 of 7

Attachment AEL-3

Attachment AEL-3
Projected Gas Cost Balances

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

Line No.	Description	Reference	Nov-16 forecast	Dec-16 forecast	Jan-17 forecast	Feb-17 forecast	Mar-17 forecast	Apr-17 forecast	May-17 forecast	Jun-17 forecast	Jul-17 forecast	Aug-17 forecast	Sep-17 forecast	Oct-17 forecast	Nov - Oct
(1)	# of Days in Month		30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
(2)	I. Fixed Cost Deferred														
(3)	Beginning Under/(Over) Recovery	Nov-16: AEL-1 pg 6, Col m, Line (19); Dec 16 - Oct 17: Previous month Line (16)	($5,220,624)	($4,732,361)	($5,726,597)	($7,886,549)	($10,186,111)	($11,902,769)	($12,252,008)	($11,263,328)	($9,294,273)	($6,884,090)	($4,409,405)	($1,996,080)	($5,220,624)
(4)	Fixed Costs (net of cap rel)	AEL-1 pg 4, Line (62)	$4,180,111	$4,159,001	$4,157,663	$4,155,641	$4,029,496	$4,294,433	$4,295,107	$4,294,433	$4,295,107	$4,295,107	$4,294,433	$4,295,107	$50,745,639
(5)	NGPMP Credits	EDA-1	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($13,700,000)
(6)	Working Capital	AEL-1 pg 8, Line (16)	$23,353	$23,232	$23,224	$23,212	$22,486	$24,011	$24,015	$24,011	$24,015	$24,015	$24,011	$24,015	$283,602
(7)	LNG Demand to DAC	Dkt 4339	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($124,066)	($1,488,790)
(8)	Supply Related LNG O & M	Dkt 4323	$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
(9)	Total Supply Fixed Costs	sum[(4):(8)]	$2,985,696	$2,964,465	$2,963,119	$2,961,086	$2,834,215	$3,100,677	$3,101,355	$3,100,677	$3,101,355	$3,101,355	$3,100,677	$3,101,355	$36,416,032
(10)	Fixed - Revenue	AEL-1 pg 7, Line (10)	($2,453,913)	($3,952,043)	($5,114,406)	($5,250,255)	($4,536,811)	($3,435,035)	($2,097,705)	($1,118,957)	($680,873)	($619,480)	($683,406)	($1,214,275)	($31,157,162)
(11)	Prelim. Ending Under/(Over) Recovery	(3) + (9) + (10)	($4,688,841)	($5,719,939)	($7,877,883)	($10,175,719)	($11,888,707)	($12,237,127)	($11,248,358)	($9,281,608)	($6,873,791)	($4,402,216)	($1,992,134)	($109,001)	
(12)	Month's Average Balance	[(3) + (11)] / 2	($4,954,733)	($5,226,150)	($6,802,240)	($9,031,134)	($11,037,409)	($12,069,948)	($11,750,183)	($10,272,468)	($8,084,032)	($5,643,153)	($3,200,770)	($1,052,541)	
(13)	Interest Rate (BOA Prime minus 200 bps)		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
(14)	Interest Applied	[(12) * (13)] / 365 * (1)	($6,109)	($6,658)	($8,666)	($10,392)	($14,061)	($14,881)	($14,969)	($12,665)	($10,299)	($7,189)	($3,946)	($1,341)	($111,176)
(15)	Marketer Reconciliation	AEL-7, Line (50)	($37,411)												($37,411)
(16)	Fixed Ending Under/(Over) Recovery	(11) + (14) + (15)	($4,732,361)	($5,726,597)	($7,886,549)	($10,186,111)	($11,902,769)	($12,252,008)	($11,263,328)	($9,294,273)	($6,884,090)	($4,409,405)	($1,996,080)	($110,342)	($110,342)
(17)	II. Variable Cost Deferred														
(18)	Beginning Under/(Over) Recovery	Nov-16: AEL-1 pg 6, Col m, Line (37); Dec 16 - Oct 17: Previous month line (32)	$6,842,292	$6,083,351	$7,957,506	$11,374,100	$11,520,707	$9,374,517	$4,808,420	$1,943,234	$896,020	$750,013	$611,477	$295,859	$6,842,292
(19)	Variable Costs	AEL-1 pg 5, Line (91)	$6,003,254	$13,116,553	$18,152,440	$15,324,592	$10,923,421	$5,212,535	$2,893,886	$1,762,033	$1,337,410	$1,151,187	$1,150,604	$2,821,345	$79,849,261
(20)	Supply Related LNG to DAC	Dkt 4339	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21)	Supply Related LNG O & M	Dkt 4323	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$572,694
(22)	Inventory Financing - LNG	AEL-1 pg 10, Line (22)	$27,075	$26,209	$12,147	$7,470	$6,874	$12,363	$17,954	$23,383	$25,224	$26,143	$31,562	$32,469	$248,872
(23)	Inventory Financing - UG	AEL-1 pg 10, Line (12)	$76,695	$62,825	$47,767	$33,975	$21,377	$29,485	$37,763	$46,548	$54,372	$63,585	$74,404	$83,861	$632,657
(24)	Working Capital	AEL-1 pg 8, Line (32)	$34,564	$75,520	$104,515	$88,233	$62,893	$30,012	$16,662	$10,145	$7,700	$6,628	$6,625	$16,244	$459,741
(25)	Total Variable Costs	sum[(19):(24)]	$6,189,313	$13,328,831	$18,364,594	$15,501,995	$11,062,289	$5,332,119	$3,013,990	$1,889,833	$1,472,431	$1,295,267	$1,310,919	$3,001,644	$81,763,225
(26)	Variable - Revenue	AEL-1 pg 7, Line (15)	($6,956,217)	($11,463,614)	($14,960,306)	($15,368,553)	($13,221,780)	($9,906,954)	($5,883,474)	($2,938,796)	($1,619,486)	($1,434,670)	($1,627,096)	($3,224,411)	($88,605,357)
(27)	Prelim. Ending Under/(Over) Recovery	(18) + (25) + (26)	$6,075,388	$7,948,568	$11,361,794	$11,507,542	$9,361,216	$4,799,683	$1,938,936	$894,271	$748,965	$610,610	$295,300	$73,092	
(28)	Month's Average Balance	[(18) + (27)] / 2	$6,458,840	$7,015,959	$9,659,650	$11,440,821	$10,440,961	$7,087,100	$3,373,678	$1,418,752	$822,493	$680,312	$453,388	$184,475	
(29)	Interest Rate (BOA Prime minus 200 bps)		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
(30)	Interest Applied	[(28) * (29)] / 365 * (1)	$7,963	$8,938	$12,306	$13,165	$13,301	$8,738	$4,298	$1,749	$1,048	$867	$559	$235	$73,167
(31)	Gas Procurement Incentive/(penalty)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(32)	Variable Ending Under/(Over) Recovery	(27) + (30) + (31)	$6,083,351	$7,957,506	$11,374,100	$11,520,707	$9,374,517	$4,808,420	$1,943,234	$896,020	$750,013	$611,477	$295,859	$73,327	$73,327
(33)	**GCR Deferred Summary**														
(34)	Beginning Under/(Over) Recovery	(3) + (18)	$1,621,668	$1,350,990	$2,230,910	$3,487,551	$1,334,596	($2,528,252)	($7,443,588)	($9,320,094)	($8,398,253)	($6,134,077)	($3,797,928)	($1,700,221)	$1,621,668
(35)	Gas Costs	sum[(4),(7):(8),(15),(19):(21)]	$10,117,577	$17,247,178	$22,281,727	$19,451,857	$14,924,541	$9,478,592	$7,160,617	$6,028,090	$5,604,141	$5,417,917	$5,416,660	$7,088,076	$130,216,974
(36)	Inventory Finance	(22) + (23)	$103,770	$89,033	$59,915	$41,445	$28,250	$41,848	$55,717	$69,931	$79,596	$89,728	$105,966	$116,330	$881,529
(37)	Working Capital	(6) + (24)	$57,918	$98,752	$127,739	$111,445	$85,379	$54,023	$40,677	$34,156	$31,716	$30,643	$30,636	$40,259	$743,342
(38)	NGPMP Credits	(5)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($1,141,667)	($13,700,000)
(39)	Total Costs	sum[(35):(38)]	$9,137,598	$16,293,297	$21,327,713	$18,463,080	$13,896,504	$8,432,796	$6,115,344	$4,990,510	$4,573,786	$4,396,622	$4,411,596	$6,102,999	$118,141,846
(40)	Revenue	(10) + (26)	($9,410,130)	($15,415,657)	($20,074,712)	($20,618,808)	($17,758,591)	($13,341,989)	($7,981,179)	($4,057,753)	($2,300,359)	($2,054,150)	($2,310,502)	($4,438,686)	($119,762,519)
(41)	Prelim. Ending Under/(Over) Recovery	(34) + (39) + (40)	$1,349,136	$2,228,629	$3,483,910	$1,331,823	($2,527,492)	($7,437,445)	($9,309,423)	($8,387,337)	($6,124,826)	($3,791,605)	($1,696,834)	($35,909)	$994
(42)	Month's Average Balance	[(34) + (41)] / 2	$1,485,402	$1,789,810	$2,857,410	$2,409,687	($596,448)	($4,982,848)	($8,376,505)	($8,853,716)	($7,261,539)	($4,962,841)	($2,747,381)	($868,065)	
(43)	Interest Rate (BOA Prime minus 200 bps)		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
(44)	Interest Applied	(14) + (30)	$1,854	$2,280	$3,640	$2,773	($760)	($6,143)	($10,671)	($10,916)	($9,251)	($6,323)	($3,387)	($1,106)	($38,009)
(45)	Gas Purchase Plan Incentives/(Penalties)	(31)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(46)	**Ending Under/(Over) Recovery W/ Interes**	(41) + (44) + (45)	$1,350,990	$2,230,910	$3,487,551	$1,334,596	($2,528,252)	($7,443,588)	($9,320,094)	($8,398,253)	($6,134,077)	($3,797,928)	($1,700,221)	**($37,015)**	($37,015)

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4647
Attachment AEL-3
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Attachment AEL-4

Attachment AEL-4
Bill Impact Analysis

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

Residential Heating:

Line No.		Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(1)												
(2)												
(3)												
(4)												
(5)		550	$806.14	$821.06	($14.92)	-1.8%	($45.23)	$30.76	$0.00	$0.00	$0.00	($0.45)
(6)		608	$872.80	$889.29	($16.49)	-1.9%	($49.98)	$33.98	$0.00	$0.00	$0.00	($0.49)
(7)		667	$940.44	$958.54	($18.10)	-1.9%	($54.84)	$37.28	$0.00	$0.00	$0.00	($0.54)
(8)		727	$1,008.25	$1,027.99	($19.74)	-1.9%	($59.76)	$40.61	$0.00	$0.00	$0.00	($0.59)
(9)		788	$1,074.06	$1,095.45	($21.39)	-2.0%	($64.78)	$44.03	$0.00	$0.00	$0.00	($0.64)
(10)	**Average Customer**	**846**	**$1,135.38**	**$1,158.32**	**($22.94)**	**-2.0%**	($69.51)	$47.26	$0.00	$0.00	$0.00	($0.69)
(11)		904	$1,196.77	$1,221.29	($24.53)	-2.0%	($74.31)	$50.52	$0.00	$0.00	$0.00	($0.74)
(12)		966	$1,262.22	$1,288.42	($26.21)	-2.0%	($79.39)	$53.97	$0.00	$0.00	$0.00	($0.79)
(13)		1,023	$1,322.25	$1,350.02	($27.77)	-2.1%	($84.11)	$57.17	$0.00	$0.00	$0.00	($0.83)
(14)		1,081	$1,382.53	$1,411.87	($29.34)	-2.1%	($88.86)	$60.40	$0.00	$0.00	$0.00	($0.88)
(15)		1,145	$1,448.09	$1,479.17	($31.08)	-2.1%	($94.11)	$63.96	$0.00	$0.00	$0.00	($0.93)

Residential Heating Low Income:

		Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(16)												
(17)												
(18)												
(19)												
(20)		550	$763.65	$778.56	($14.92)	-1.9%	($45.23)	$30.76	$0.00	$0.00	$0.00	($0.45)
(21)		608	$827.56	$844.06	($16.49)	-2.0%	($49.98)	$33.98	$0.00	$0.00	$0.00	($0.49)
(22)		667	$892.43	$910.53	($18.10)	-2.0%	($54.84)	$37.28	$0.00	$0.00	$0.00	($0.54)
(23)		727	$957.53	$977.27	($19.74)	-2.0%	($59.76)	$40.61	$0.00	$0.00	$0.00	($0.59)
(24)		788	$1,020.88	$1,042.27	($21.39)	-2.1%	($64.78)	$44.03	$0.00	$0.00	$0.00	($0.64)
(25)	**Average Customer**	**846**	**$1,079.98**	**$1,102.92**	**($22.94)**	**-2.1%**	($69.51)	$47.26	$0.00	$0.00	$0.00	($0.69)
(26)		904	$1,139.16	$1,163.69	($24.53)	-2.1%	($74.31)	$50.52	$0.00	$0.00	$0.00	($0.74)
(27)		966	$1,202.26	$1,228.47	($26.21)	-2.1%	($79.39)	$53.97	$0.00	$0.00	$0.00	($0.79)
(28)		1,023	$1,260.15	$1,287.92	($27.77)	-2.2%	($84.11)	$57.17	$0.00	$0.00	$0.00	($0.83)
(29)		1,081	$1,318.32	$1,347.66	($29.34)	-2.2%	($88.86)	$60.40	$0.00	$0.00	$0.00	($0.88)
(30)		1,145	$1,381.65	$1,412.74	($31.08)	-2.2%	($94.11)	$63.96	$0.00	$0.00	$0.00	($0.93)

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

Residential Non-Heating:

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
		---	---	---	---	---	---	---	---	---	---
	140	$336.77	$338.07	($1.30)	-0.4%	($11.09)	$9.83	$0.00	$0.00	$0.00	($0.04)
	155	$354.65	$356.05	($1.40)	-0.4%	($12.27)	$10.91	$0.00	$0.00	$0.00	($0.04)
	171	$373.72	$375.31	($1.59)	-0.4%	($13.57)	$12.03	$0.00	$0.00	$0.00	($0.05)
	184	$389.25	$390.89	($1.64)	-0.4%	($14.57)	$12.98	$0.00	$0.00	$0.00	($0.05)
	198	$405.89	$407.70	($1.81)	-0.4%	($15.68)	$13.92	$0.00	$0.00	$0.00	($0.05)
Average Customer	**214**	**$424.60**	**$426.53**	**($1.94)**	**-0.5%**	($16.92)	$15.04	$0.00	$0.00	$0.00	($0.06)
	228	$441.68	$443.75	($2.07)	-0.5%	($18.06)	$16.05	$0.00	$0.00	$0.00	($0.06)
	244	$460.74	$462.97	($2.23)	-0.5%	($19.33)	$17.17	$0.00	$0.00	$0.00	($0.07)
	258	$477.44	$479.81	($2.37)	-0.5%	($20.45)	$18.15	$0.00	$0.00	$0.00	($0.07)
	275	$497.71	$500.22	($2.52)	-0.5%	($21.80)	$19.36	$0.00	$0.00	$0.00	($0.08)
	288	$513.21	$515.84	($2.63)	-0.5%	($22.84)	$20.29	$0.00	$0.00	$0.00	($0.08)

Residential Non-Heating Low Income:

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
		---	---	---	---	---	---	---	---	---	---
	140	$314.35	$315.65	($1.30)	-0.4%	($11.09)	$9.83	$0.00	$0.00	$0.00	($0.04)
	155	$331.56	$332.96	($1.40)	-0.4%	($12.27)	$10.91	$0.00	$0.00	$0.00	($0.04)
	171	$349.90	$351.49	($1.59)	-0.5%	($13.57)	$12.03	$0.00	$0.00	$0.00	($0.05)
	184	$364.84	$366.48	($1.64)	-0.4%	($14.57)	$12.98	$0.00	$0.00	$0.00	($0.05)
	198	$380.85	$382.66	($1.81)	-0.5%	($15.68)	$13.92	$0.00	$0.00	$0.00	($0.05)
Average Customer	**214**	**$398.84**	**$400.78**	**($1.94)**	**-0.5%**	($16.92)	$15.04	$0.00	$0.00	$0.00	($0.06)
	228	$415.28	$417.35	($2.07)	-0.5%	($18.06)	$16.05	$0.00	$0.00	$0.00	($0.06)
	244	$433.62	$435.84	($2.23)	-0.5%	($19.33)	$17.17	$0.00	$0.00	$0.00	($0.07)
	258	$449.68	$452.05	($2.37)	-0.5%	($20.45)	$18.15	$0.00	$0.00	$0.00	($0.07)
	275	$469.18	$471.69	($2.52)	-0.5%	($21.80)	$19.36	$0.00	$0.00	$0.00	($0.08)
	288	$484.10	$486.73	($2.63)	-0.5%	($22.84)	$20.29	$0.00	$0.00	$0.00	($0.08)

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

C & I Small:

						Difference due to:					
	Annual	Proposed	Current				DAC				
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
	880	$1,300.88	$1,315.61	($14.73)	-1.1%	($72.36)	$58.07	$0.00	$0.00	$0.00	($0.44)
	973	$1,394.87	$1,411.16	($16.29)	-1.2%	($79.98)	$64.18	$0.00	$0.00	$0.00	($0.49)
	1,067	$1,489.05	$1,506.92	($17.87)	-1.2%	($87.72)	$70.39	$0.00	$0.00	$0.00	($0.54)
	1,162	$1,581.79	$1,601.28	($19.48)	-1.2%	($95.54)	$76.64	$0.00	$0.00	$0.00	($0.58)
	1,258	$1,669.92	$1,690.92	($21.00)	-1.2%	($103.39)	$83.02	$0.00	$0.00	$0.00	($0.63)
Average Customer	**1,352**	**$1,755.04**	**$1,777.63**	**($22.60)**	**-1.3%**	($111.11)	$89.19	$0.00	$0.00	$0.00	($0.68)
	1,446	$1,840.83	$1,865.08	($24.26)	-1.3%	($118.89)	$95.36	$0.00	$0.00	$0.00	($0.73)
	1,542	$1,927.91	$1,953.72	($25.80)	-1.3%	($126.77)	$101.74	$0.00	$0.00	$0.00	($0.77)
	1,635	$2,012.38	$2,039.71	($27.33)	-1.3%	($134.39)	$107.88	$0.00	$0.00	$0.00	($0.82)
	1,730	$2,097.60	$2,126.53	($28.93)	-1.4%	($142.20)	$114.14	$0.00	$0.00	$0.00	($0.87)
	1,825	$2,182.80	$2,213.34	($30.55)	-1.4%	($150.01)	$120.38	$0.00	$0.00	$0.00	($0.92)

C & I Medium:

						Difference due to:					
	Annual	Proposed	Current				DAC				
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
	7,941	$7,964.85	$8,214.76	($249.91)	-3.0%	($652.76)	$410.35	$0.00	$0.00	$0.00	($7.50)
	8,796	$8,728.57	$9,005.42	($276.85)	-3.1%	($723.04)	$454.50	$0.00	$0.00	$0.00	($8.31)
	9,650	$9,490.90	$9,794.59	($303.69)	-3.1%	($793.24)	$498.66	$0.00	$0.00	$0.00	($9.11)
	10,505	$10,254.69	$10,585.28	($330.59)	-3.1%	($863.51)	$542.84	$0.00	$0.00	$0.00	($9.92)
	11,361	$11,018.61	$11,376.15	($357.54)	-3.1%	($933.86)	$587.05	$0.00	$0.00	$0.00	($10.73)
Average Customer	**12,217**	**$11,782.85**	**$12,167.30**	**($384.45)**	**-3.2%**	($1,004.22)	$631.30	$0.00	$0.00	$0.00	($11.53)
	13,073	$12,547.05	$12,958.46	($411.41)	-3.2%	($1,074.60)	$675.53	$0.00	$0.00	$0.00	($12.34)
	13,928	$13,310.20	$13,748.54	($438.34)	-3.2%	($1,144.90)	$719.71	$0.00	$0.00	$0.00	($13.15)
	14,782	$14,073.13	$14,538.35	($465.22)	-3.2%	($1,215.10)	$763.84	$0.00	$0.00	$0.00	($13.96)
	15,637	$14,836.25	$15,328.40	($492.15)	-3.2%	($1,285.39)	$808.00	$0.00	$0.00	$0.00	($14.76)
	16,492	$15,600.03	$16,119.06	($519.03)	-3.2%	($1,355.64)	$852.18	$0.00	$0.00	$0.00	($15.57)

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

C & I LLF Large:

						Difference due to:					
	Annual	Proposed	Current				DAC				
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(91)	41,066	$38,863.47	$41,712.70	($2,849.23)	-6.8%	($3,375.64)	$611.89	$0.00	$0.00	$0.00	($85.48)
(92)	45,488	$42,814.18	$45,970.21	($3,156.03)	-6.9%	($3,739.11)	$677.76	$0.00	$0.00	$0.00	($94.68)
(93)	49,910	$46,764.88	$50,227.75	($3,462.88)	-6.9%	($4,102.65)	$743.66	$0.00	$0.00	$0.00	($103.89)
(94)	54,334	$50,717.27	$54,487.02	($3,769.75)	-6.9%	($4,466.26)	$809.60	$0.00	$0.00	$0.00	($113.09)
(95)	58,757	$54,668.78	$58,745.41	($4,076.63)	-6.9%	($4,829.82)	$875.49	$0.00	$0.00	$0.00	($122.30)
(96)	**63,179**	**$58,619.68**	**$63,003.13**	**($4,383.44)**	**-7.0%**	($5,193.30)	$941.36	$0.00	$0.00	$0.00	($131.50)
(97)	67,600	$62,569.47	$67,259.68	($4,690.21)	-7.0%	($5,556.73)	$1,007.23	$0.00	$0.00	$0.00	($140.71)
(98)	72,023	$66,521.07	$71,518.10	($4,997.03)	-7.0%	($5,920.29)	$1,073.17	$0.00	$0.00	$0.00	($149.91)
(99)	76,447	$70,473.95	$75,777.93	($5,303.98)	-7.0%	($6,283.94)	$1,139.08	$0.00	$0.00	$0.00	($159.12)
(100)	80,870	$74,425.46	$80,036.34	($5,610.88)	-7.0%	($6,647.51)	$1,204.96	$0.00	$0.00	$0.00	($168.33)
(101)	85,292	$78,376.19	$84,293.89	($5,917.70)	-7.0%	($7,011.02)	$1,270.85	$0.00	$0.00	$0.00	($177.53)

Average Customer

C & I HLF Large:

						Difference due to:					
	Annual	Proposed	Current				DAC				
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(106)	50,411	$41,225.46	$44,790.59	($3,565.13)	-8.0%	($3,997.58)	$539.40	$0.00	$0.00	$0.00	($106.95)
(107)	55,841	$45,431.89	$49,381.02	($3,949.12)	-8.0%	($4,428.15)	$597.50	$0.00	$0.00	$0.00	($118.47)
(108)	61,273	$49,639.63	$53,972.92	($4,333.29)	-8.0%	($4,858.93)	$655.64	$0.00	$0.00	$0.00	($130.00)
(109)	66,699	$53,843.28	$58,560.34	($4,717.05)	-8.1%	($5,289.24)	$713.70	$0.00	$0.00	$0.00	($141.51)
(110)	72,129	$58,049.67	$63,150.75	($5,101.08)	-8.1%	($5,719.84)	$771.79	$0.00	$0.00	$0.00	($153.03)
(111)	**77,558**	**$62,255.29**	**$67,740.36**	**($5,485.07)**	**-8.1%**	($6,150.39)	$829.87	$0.00	$0.00	$0.00	($164.55)
(112)	82,989	$66,461.68	$72,330.80	($5,869.12)	-8.1%	($6,581.03)	$887.98	$0.00	$0.00	$0.00	($176.07)
(113)	88,416	$70,666.03	$76,918.92	($6,252.90)	-8.1%	($7,011.37)	$946.06	$0.00	$0.00	$0.00	($187.59)
(114)	93,847	$74,873.13	$81,510.11	($6,636.98)	-8.1%	($7,442.04)	$1,004.17	$0.00	$0.00	$0.00	($199.11)
(115)	99,275	$79,078.13	$86,099.02	($7,020.89)	-8.2%	($7,872.53)	$1,062.27	$0.00	$0.00	$0.00	($210.63)
(116)	104,705	$83,284.54	$90,689.44	($7,404.91)	-8.2%	($8,303.11)	$1,120.35	$0.00	$0.00	$0.00	($222.15)
(117)											
(118)											
(119)											
(120)											

Average Customer

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

C & I LLF Extra-Large:

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
		---	---	---	---	---	---	---	---	---	---
	174,357	$124,202.71	$138,618.65	($14,415.94)	-10.4%	($14,332.18)	$348.72	$0.00	$0.00	$0.00	($432.48)
	193,136	$137,012.31	$152,980.87	($15,968.56)	-10.4%	($15,875.79)	$386.29	$0.00	$0.00	$0.00	($479.06)
	211,912	$149,820.05	$167,341.03	($17,520.98)	-10.5%	($17,419.17)	$423.82	$0.00	$0.00	$0.00	($525.63)
	230,688	$162,628.45	$181,701.82	($19,073.37)	-10.5%	($18,962.57)	$461.40	$0.00	$0.00	$0.00	($572.20)
	249,466	$175,437.42	$196,063.38	($20,625.96)	-10.5%	($20,506.09)	$498.91	$0.00	$0.00	$0.00	($618.78)
Average Customer	**268,243**	**$188,245.72**	**$210,424.13**	**($22,178.41)**	**-10.5%**	($22,049.56)	$536.50	$0.00	$0.00	$0.00	($665.35)
	287,018	$201,053.04	$224,783.78	($23,730.74)	-10.6%	($23,592.88)	$574.06	$0.00	$0.00	$0.00	($711.92)
	305,796	$213,862.56	$239,145.94	($25,283.38)	-10.6%	($25,136.45)	$611.57	$0.00	$0.00	$0.00	($758.50)
	324,573	$226,670.93	$253,506.77	($26,835.85)	-10.6%	($26,679.94)	$649.17	$0.00	$0.00	$0.00	($805.08)
	343,350	$239,479.31	$267,867.62	($28,388.31)	-10.6%	($28,223.37)	$686.71	$0.00	$0.00	$0.00	($851.65)
	362,127	$252,287.73	$282,228.56	($29,940.82)	-10.6%	($29,766.85)	$724.25	$0.00	$0.00	$0.00	($898.22)

C & I HLF Extra-Large:

	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
		---	---	---	---	---	---	---	---	---	---
	447,421	$288,080.21	$324,012.29	($35,932.07)	-11.1%	($35,480.49)	$626.38	$0.00	$0.00	$0.00	($1,077.96)
	495,605	$318,536.84	$358,338.53	($39,801.69)	-11.1%	($39,301.47)	$693.83	$0.00	$0.00	$0.00	($1,194.05)
	543,789	$348,994.28	$392,665.64	($43,671.36)	-11.1%	($43,122.50)	$761.28	$0.00	$0.00	$0.00	($1,310.14)
	591,972	$379,450.37	$426,991.18	($47,540.81)	-11.1%	($46,943.37)	$828.78	$0.00	$0.00	$0.00	($1,426.22)
	640,155	$409,906.47	$461,316.83	($51,410.36)	-11.1%	($50,764.29)	$896.24	$0.00	$0.00	$0.00	($1,542.31)
Average Customer	**688,340**	**$440,364.14**	**$495,644.23**	**($55,280.08)**	**-11.2%**	($54,585.34)	$963.66	$0.00	$0.00	$0.00	($1,658.40)
	736,523	$470,820.52	$529,970.14	($59,149.62)	-11.2%	($58,406.27)	$1,031.14	$0.00	$0.00	$0.00	($1,774.49)
	784,708	$501,277.69	$564,297.06	($63,019.37)	-11.2%	($62,227.36)	$1,098.57	$0.00	$0.00	$0.00	($1,890.58)
	832,891	$531,734.58	$598,623.43	($66,888.86)	-11.2%	($66,048.26)	$1,166.07	$0.00	$0.00	$0.00	($2,006.67)
	881,074	$562,190.64	$632,949.13	($70,758.48)	-11.2%	($69,869.20)	$1,233.47	$0.00	$0.00	$0.00	($2,122.75)
	929,259	$592,648.66	$667,276.75	($74,628.09)	-11.2%	($73,690.22)	$1,300.97	$0.00	$0.00	$0.00	($2,238.84)

Attachment AEL-5
FT-2 Demand Rate

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

Line No.	Item	Reference	Proposed	Billing Units
	(a)	(b)	(c)	(d)
(1)	FT-2 Demand	Pg 2, Line (21)	**$8.0484**	Dth/Mth
(2)	Weighted Average Upstream Pipeline Transportation Cost	EDA - 4	**$0.3119**	Per Dth of capacity
(3)	Storage and Peaking charge for FT-1 firm transportation Customers eligible for TSS	Pg 3, Line (5)	**$0.6802**	Per Dth

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

Line No.	Description	Source Reference	Source Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Storage Fixed Costs	AEL-1 pg 4	Line (61)	$15,406,775	
	Less:				
(2)	LNG Demand to DAC	AEL-1 pg 2	Line (5)	($1,488,790)	
(3)	Credits			$0	
(4)	Refunds			$0	
(5)	Total Credits	sum [(2):(4)]		($1,488,790)	
	Plus:				
(6)	Supply Related LNG O&M Costs	Dkt 4323		$575,581	
(7)	Working Capital Requirement	AEL-1 pg 9	Line (47)	$80,134	
(8)	Tennessee Dracut for peaking	AEL-1 pg 4	Line (5)	$1,622,277	
(9)	Total Additions	sum [(6):(8)]		$2,277,992	
(10)	Total Storage Fixed Costs	(1) + (5) + (9)		$16,195,978	
	Inventory Financing				
(11)	Underground	AEL-1 pg 10	Line (12)	$632,657	
(12)	LNG	AEL-1 pg 10	Line (22)	$248,872	
(13)	Total Storage Fixed Costs	(10) + (11) + (12)		$17,077,507	
(14)	LNG Storage MDQ (Dth)	AEL-1 pg 12	Line (14)	140,110	
(15)	AGT	EDA-4		31,681	
(16)	TENN	EDA-4		10,836	
(17)	Total Storage MDQ	sum [(14):(16)]		182,627	
(18)	Storage MDQ X 12 Months	(17) *12		2,191,524	MDCQ Dth
(19)	FT- 2 Demand Rate	(13) / (18)		$7.7925	per MDCQ Dth
(20)	Uncollectible %	Docket 4323		3.18%	
(21)	Total FT-2 Demand Rate adjusted for Uncollectibles	(19) / [(1 - (20)]		$8.0484	per MDCQ Dth
(22)	MDQ-U	Mkter MDQ Forecast		4,380	
(23)	MDQ-P	Mkter MDQ Forecast		15,095	
(24)	Marketer MDQs	(22) + (23)		19,475	Dth/Mth
(25)	**FT-2 Storage Costs**	(19) x (24) x 12 Months		**$1,821,075**	

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

Line No.	Description	Source Reference	Source Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Total Storage Fixed Costs	Pg 2	Line (13)	$17,077,507	
(2)	Usage (Dt) Nov 2016 - Oct 2017	AEL-1 pg 2	Line (16)	25,929,986	
(3)	Volumetric Rate	(1) / (2)		$0.6586	
(4)	Uncollectible %	Docket 4323		3.18%	
(5)	Volumetric Rate Including Uncollectible	(3) / [1 - (4)]		$0.6802	per dth
(6)	**Storage and Peaking charge applied to FT-1 firm transportation Customers eligible for TSS**			$0.0680	per therm

Attachment AEL-6

Attachment AEL-6
FT-2 Capacity Allocator Percentages

RI Gas Company
Capacity Assignment Table

Line No.	Load (a)	Rate Class (b)	% of Peak Day Requirement Pipeline (c)	Storage (d)	Peaking (e)	Total (f)	% of Total Capacity Pipeline (g)	Storage (h)	Peaking (i)
(1)	HLF	Res - Non-Heating	58.0%	9.0%	33.0%	100.0%	1.7%	1.6%	1.6%
(2)	HLF	Res - Non-Heating LI	58.0%	9.0%	33.0%	100.0%			
(3)	LLF	Res - Heating	47.0%	12.0%	41.0%	100.0%	57.6%	59.7%	59.7%
(4)	LLF	Res - Heating LI	47.0%	12.0%	41.0%	100.0%			
(5)	LLF	Small	47.0%	12.0%	41.0%	100.0%	7.8%	8.3%	8.3%
(6)	LLF	Med	47.0%	12.0%	41.0%	100.0%	9.4%	9.2%	9.2%
(7)	LLF	Large Low Load	47.0%	12.0%	41.0%	100.0%	2.2%	2.3%	2.3%
(8)	HLF	Large High Load	58.0%	9.0%	33.0%	100.0%	0.5%	0.3%	0.3%
(9)	LLF	XL Low Load	47.0%	12.0%	41.0%	100.0%	0.2%	0.2%	0.2%
(10)	HLF	XL High Load	58.0%	9.0%	33.0%	100.0%	0.2%	0.0%	0.0%
(11)	HLF	High Load Factor	58.0%	9.0%	33.0%	100.0%	8.9%	5.9%	5.9%
(12)	LLF	Low Load Factor	47.0%	12.0%	41.0%	100.0%	91.1%	94.1%	94.1%
(13)		Total	48.0%	12.0%	41.0%	100.0%	100.0%	100.0%	100.0%

Attachment AEL-7

Attachment AEL-7
Marketer Reconciliation

2014-15 & 2015-16 Annual Marketer Reconciliation

	(a)	# of days (b)	Reference (c)	Tetco ELA/Algonquin (d)	Tetco WLA/Algonquin (e)	Tennessee Zone 1 to NEGC (f)	Tetco STX/Algonquin (g)	Algonquin @ Lambertville, NJ (h)	Columbia (Maumee/Downington) (i)	Total (j)
	2015-2016 Marketer Reconciliation									
	Month of activity									
(1)	**Nov-15**	30		195,000	255,000	285,000	121,320	81,420	32,040	969,780
(2)	**Dec-15**	31		201,500	263,469	294,500	125,364	84,134	39,308	1,008,275
(3)	**Jan-16**	31		201,500	263,500	294,500	125,364	84,134	58,683	1,027,681
(4)	**Feb-16**	29		188,500	246,500	275,471	117,247	78,706	57,797	964,221
(5)	**Mar-16**	31		201,500	263,500	294,500	125,364	84,134	68,727	1,037,725
(6)	**Apr-16**	30		195,000	255,000	285,000	121,290	81,420	80,220	1,017,930
(7)	**May-16**	31		201,469	263,500	294,500	125,364	84,134	83,948	1,052,915
(8)	**Jun-16**	30		194,970	255,000	285,000	121,290	81,420	79,830	1,017,510
(9)	**Jul-16**	31		201,500	263,500	294,500	125,364	84,134	81,685	1,050,683
(10)	**Aug-16**	31		201,469	263,500	294,469	125,364	84,134	77,283	1,046,219
(11)	**Sep-16**	30		194,970	255,000	284,970	121,320	81,420	74,790	1,012,470
(12)	**Oct-16**	31		201,469	263,500	294,469	125,364	84,134	77,283	1,046,219
(13)	**Total**		sum[(1):(12)]	2,378,847	3,110,969	3,476,879	1,480,015	993,324	811,594	12,251,628
	Approved									
(14)	System Average		Dkt 4576 EDA-4	$0.4219	$0.4219	$0.4219	$0.4219	$0.4219	$0.4219	
(15)	Path		Dkt 4576 EDA-4	$0.8797	$1.0025	$1.0482	$1.2561	$0.0500	$0.3634	
(16)	Credit/Surcharge		(14) - (15)	($0.4578)	($0.5806)	($0.6263)	($0.8342)	$0.3719	$0.0585	
	Revised									
(17)	System Average			$0.4183	$0.4183	$0.4183	$0.4183	$0.4183	$0.4183	
(18)	Path			$0.8797	$1.0025	$1.0257	$1.2561	$0.0500	$0.3634	
(19)	Credit/Surcharge		(17) - (18)	($0.4614)	($0.5842)	($0.6074)	($0.8378)	$0.3683	$0.0549	
(20)	Variance- approved Surcharge/Credit vs. Revised Surcharge/Credit		(19) - (16)	($0.0036)	($0.0036)	$0.0189	($0.0036)	($0.0036)	($0.0036)	
(21)	Annual MDCQ		(13)	2,378,847	3,110,969	3,476,879	1,480,015	993,324	811,594	12,251,628
(22)	Updated 2015-16 Marketer Reconciliation Adjustment		(20) * (21)	($8,564)	($11,199)	$65,713	($5,328)	($3,576)	($2,922)	$34,124

2014-15 & 2015-16 Annual Marketer Reconciliation

	2014-2015 Marketer Reconciliation									
	Month of activity									
(23)	**Nov-14**	30		86,610	255,000	285,000	112,380	61,590	0	800,580
(24)	**Dec-14**	31		91,109	263,500	294,500	115,754	63,581	0	828,444
(25)	**Jan-15**	31		93,837	263,438	294,469	115,909	62,651	0	830,304
(26)	**Feb-15**	28		88,284	237,972	266,000	104,916	56,980	0	754,152
(27)	**Mar-15**	31		108,097	263,500	294,500	116,932	63,736	0	846,765
(28)	**Apr-15**	30		116,550	255,000	285,000	113,340	61,350	0	831,240
(29)	**May-15**	31		120,869	263,500	294,500	117,025	63,643	0	859,537
(30)	**Jun-15**	30		118,500	255,000	285,000	113,520	61,530	0	833,550
(31)	**Jul-15**	31		134,664	263,500	294,469	118,544	62,837	0	874,014
(32)	**Aug-15**	31		135,687	263,500	294,500	118,668	62,775	0	875,130
(33)	**Sep-14**	30		137,220	254,970	284,970	115,260	60,690	0	853,110
(34)	**Oct-15**	31		148,428	263,469	294,469	120,094	63,581	0	890,041
(35)	**Total**		sum[(23):(34)]	1,379,855	3,102,349	3,467,377	1,382,342	744,944	0	10,076,867
	Approved									
(36)	System Average		Dkt 4520 EDA-4	$0.5039	$0.5039	$0.5039	$0.5039	$0.5039	$0.5039	
(37)	Path		Dkt 4520 EDA-4	$0.9217	$1.0177	$1.1079	$1.3049	$0.0524	$0.2686	
(38)	Credit/Surcharge		(36) - (37)	($0.4178)	($0.5138)	($0.6040)	($0.8010)	$0.4515	$0.2353	
	Revised									
(39)	System Average			$0.5114	$0.5114	$0.5114	$0.5114	$0.5114	$0.5114	
(40)	Path			$0.9267	$1.0228	$1.1092	$1.3099	$0.0574	$0.2736	
(41)	Credit/Surcharge		(39) - (40)	($0.4153)	($0.5114)	($0.5978)	($0.7985)	$0.4540	$0.2378	
(42)	Variance- approved Surcharge/Credit vs. Revised Surcharge/Credit		(41) - (38)	$0.0025	$0.0024	$0.0062	$0.0025	$0.0025	$0.0025	
(43)	Annual MDCQ		(35)	1,379,855	3,102,349	3,467,377	1,382,342	744,944	0	10,076,867
(44)	Updated 2014-15 Marketer Reconciliation Adjustment		(42) * (43)	$3,450	$7,446	$21,498	$3,456	$1,862	$0	$37,711
(45)	Under/(Over)-collections for 2012-13 & 2013-14 Marketer Reconciliation[1]									$18,132
(46)	Total 2012-15 amount subject to Marketer Reconciliation		(44) + (45)							$55,843
(47)	Already Collected from Marketers[2]									$52,556
(48)	Under/(Over)-collections for 2013-14 & 2014-15 Marketer Reconciliation		(46) - (47)							$3,287
(49)	**Total 2014-15 & 2015-16 Marketer Reconciliation- Surcharge to Marketers**		(22) + (48)							$37,411
(50)	**Total 2014-15 & 2015-16 Marketer Reconciliation- Surcharge Credited to Firm Sales Customers**		- (49)							**($37,411)**

[1] Docket No. 4576 Attachment AEL-7, Line 48, filed on September 2, 2015 updated to reflect actual collections for Aug. 2015-Oct. 2015.

[2] Nov. 2015 - July 2016 as reflected in GCR Monthly Deferred Report filed on August 20, 2016 Schedule 2, Line 74. Aug. 2016-Oct. 2016 are projected collections.

Testimony of
Theodore E. Poe, Jr.

DIRECT TESTIMONY

OF

THEODORE E. POE, JR.

September 1, 2016

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I. Introduction

Q. Please state your name and business address.

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

Q. What is your position and responsibilities within that position?

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

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

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science degree in Geology. From 1981 to 1989, I worked as a Research Associate with Jensen Associates, Inc. of Boston where I was responsible for developing a variety of

computer-forecasting models to analyze natural gas supply and demand for interstate pipeline and LDCs. I joined Boston Gas in 1989, where I was responsible for modeling and forecasting the natural gas resource requirements of customers and managing the resource-planning process. In 1998-99, I assumed the same responsibilities for Essex Gas Company and Colonial. In 2000, I added the responsibility of modeling and forecasting the natural gas resource requirements of Brooklyn Gas and KeySpan. Then in 2008, I added the responsibility of modeling and forecasting the natural-gas resource requirements of the Company, as well as Niagara Mohawk.

Q. Are you a member of any professional organizations?

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

Q. Have you previously testified in regulatory proceedings?

A. Yes. I submitted pre-filed written testimony in last year's Gas Cost Recovery filing, Docket No. 4576. I have also testified in a number of proceedings before the Department of Public Utilities in the Commonwealth of Massachusetts and the Public Utilities Commission in New Hampshire.

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

A. My testimony provides support for the underlying retail and wholesale forecasts of natural gas customer requirements that is used to estimate gas costs in the Company's Gas Cost Recovery submission.

Q. Are you sponsoring any Attachments?

A. Yes. I am sponsoring the following attachments:

Attachment TEP-1	National Grid RI Retail Volume Forecast 2016Q2 vs. 2015Q2 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2016Q2 vs. 2015Q2 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2016Q2 vs. 2015Q2 Forecast

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

A. As in prior cost of gas filings, the Company used projected sendout requirements and costs from its internal budgets and forecasts.

II. Summary of Retail and Wholesale Natural Gas Forecasts

Q. Please describe the Company's process for developing its retail and wholesale forecasts.

A. Annually, beginning on April 1st, the Company prepares its ten-year forecast of customer requirements using a five-step process:

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

In this instance, "retail" refers to gas delivered and metered at the Company's customers' burner tips, and "wholesale" refers to gas received and metered flowing into the Company's distribution system. This process and forecasting methodology is more fully documented in the Company's 2015/16 to 2024/25 Gas Long-Range Resource and Requirements Plan (Gas Long-Range Plan) submitted on March 10, 2016 in Docket No. 4608. The Company's retail forecast is prepared through econometric and statistical modeling of both customer count (meter count) and use per customer. Billing data is modeled at the rate class level and further sub-categorized as sales or transportation (either capacity-eligible or capacity-exempt). The Company's volume forecast is then the product of meter count and use per customer at the rate class level. The retail forecast takes into account the impact of the Company's energy efficiency programs. The Company's wholesale forecast is then based on its retail forecast. The retail forecast is adjusted to correct for the billing lag inherent therein, and it is further adjusted to account

for unaccounted-for gas. Unaccounted-for gas is the accounting of the difference between gas supplies that are received and metered flowing into the Company's distribution system and gas delivered and metered at the Company's customers' burner tips. These two forecasts (retail and wholesale) then serve as the annual basis of the Company's supply, engineering, and financial planning.

III. The 2016 Gas Forecast

Q. Please describe the role of the 2016 Gas Forecast in the Gas Cost Recovery (GCR) proceeding?

A. With a significant portion of the Company's sales going to spaceheating use, its gas resource portfolio and gas supply purchase planning are designed to address its customers' needs during the winter peak period and throughout the year. Each year, the Company constructs its Gas Forecast by adding in the most recent heating season's usage patterns by its customers. This provides the Company a growing set of historical data with which to build its econometric forecast using its most recent economic outlook.

The Company's forecast of sales and throughput requirements under normal weather conditions and under design winter conditions serves three purposes. First, the forecasts provide key inputs for the computation of National Grid's projected GCR costs. Second, the Company's forecasts of design winter requirements form the basis for the Company's allocation of Fixed Costs between high load factor and low load factor service

classifications. Third, forecasts of total annual sales and throughput requirements provide the denominators for used in the Company's computation of applicable charges on a dollars per therm basis. The Company's forecasts of future gas service requirements also serve as important indicators of the need for additional capacity to ensure the reliability of its service, particularly during periods of extreme weather, as reflected in measures of design winter, cold snap, and design day requirements. The Company's long-range forecasts of service requirements also play an important role in National Grid's assessment of the economics of alternative gas supply resources.

Q. How does the 2016 Gas Forecast compare to that which is set forth in the Gas Long-Range Plan for the 2015/16 to 2024/25 period?

A. The Company's Gas Long-Range Plan for the Forecast Period 2015/16 to 2024/25 was filed on March 10, 2016, just prior to the Company's annual forecasting cycle that produced the 2016 Gas Forecast. Overall, it predicted 2016/17 total retail sales for 0.9 percent higher than the current forecast.

The Company's 2016 Gas Forecast of retail sales for the period November 2016 – October 2017 is summarized in Table 1, below:

Table 1

	2016/17 Volume (MMBtu)
Residential Sales	19,464,284
Commercial/Industrial Sales	6,431,813
Total Sales	25,896,097
Commercial/Industrial Transportation	13,451,243
Total Sales and Transportation	39,347,340

Comparatively, the Company's retail forecast as filed in its Gas Long-Range Plan for November 2016 – October 2017 is shown in Table 2, below:

Table 2

	2016/17 Volume (MMBtu)
Residential Sales	19,723,960
Commercial/Industrial Sales	7,211,189
Total Sales	26,935,149
Commercial/Industrial Transportation	12,753,780
Total Sales and Transportation	39,688,928

Q. How do the forecasted sales requirements for 2016/17 compare to the prior retail forecast for 2015/16?

A. The Company's 2016 Gas Forecast of retail sales for the period November 2016 – October 2017 is shown in Table 1, above. Comparatively, the Company's previous retail forecast (as filed in Docket No. 4576) for November 2015 – October 2016 is shown in Table 3, below:

Table 3

	2015/16 Volume (MMBtu)
Residential Sales	19,424,203
Commercial/Industrial Sales	7,585,647
Total Sales	27,009,851
Commercial/Industrial Transportation	12,887,190
Total Sales and Transportation	39,897,041

In summary, the overall Total Sales and Transportation shows a 1.4 percent decrease, with Total Sales decreasing by 4.1 percent and Commercial/Industrial Transportation increasing by 4.4 percent.

Attachment TEP-1 contains tables for planning year (PY, November – October) volumes from PY2011 through PY2026 for the Company's current (2016Q2) volume forecast as well as last year's (2015Q2) forecast. The data is presented for Residential Non-Heating, Residential Heating, Commercial / Industrial (C&I) Sales, C&I FT1 Transportation, C&I FT2 Transportation, and all other volumes. Charts are provided for visual comparison. The primary changes in the volume forecast from 2015Q2 to 2016Q2 are a slowing in the reduction of Residential Non-Heating volumes and lower C&I Sales forecast. The five-year per-annum growth rate in volumes (excluding Other) from PY2017 to PY2022 is 0.6 percent, which is lower than the 1.0 percent per-annum growth rate in last year's forecast. Attachment TEP-2 contains tables for planning year volumes from PY2011 through PY2026 for the Company's current (2016Q2) meter count forecast as well as last year's

(2015Q2) forecast. The data is presented for Residential Non-Heating, Residential Heating, Commercial / Industrial (C&I) Sales, C&I FT1 Transportation, C&I FT2 Transportation, and all other volumes. Charts are provided for visual comparison. The primary changes in the meter count forecast from 2015Q2 to 2016Q2 are a slowing in the reduction of Residential Non-Heating, and lower growth in Residential Heating and C&I Sales customer growth. The five-year per-annum growth rate in meter count (excluding Other) from PY2017 to PY2022 is 0.6 percent, which is lower than the 1.0 percent per annum growth rate in last year's forecast.

On a wholesale basis (see Attachment EDA-2, page 1), the Company forecasts Sales volumes to be 26,677,543 MMBtu for the period November 2016 – October 2017. Comparatively, in the Company's previous wholesale forecast (as filed in Docket No. 4576) for November 2015 – October 2016, the Sales volume was projected to be 27,962,300 MMBtu. The wholesale Sales volume growth rate is a decrease of 4.6 percent.

Attachment TEP-3 contains tables for calendar year economic data from 1990 – 2026 for the Company's current (2016Q2) forecast as well as last year's (2015Q2) forecast. The data are presented for the following key indicators: Natural Gas Residential Price, Residential No.2 Oil Price, the gas-to-oil price ratio (GORR), Rhode Island GDP, Households, and Non-Farm Employment. Charts are provided for visual comparison.

While the overall 2016Q2 economic forecast is slightly lower than the 2015Q2 forecast, the primary factors affecting the Company's forecast are a higher gas price forecast, a significantly lower oil price forecast, and a much higher gas-to-oil price ratio.

Q. Please explain the reasons why the 2016/2017 Forecast is less than the 2015/2016 Forecast used in last year's 2015-2016 GCR and DAC filings.

A. As I state above, the primary factors affecting the Company's forecast are a higher gas price forecast, a significantly lower oil price forecast, and a much higher gas-to-oil price ratio. These price factors affect the demand for natural gas in both the residential and commercial / industrial markets. Recently, when the price of crude oil was in the range of $100/bbl, while natural gas prices were significantly lower on a Btu basis, the Company received a significant number of requests for conversion from oil to natural gas from both markets. With the drop in crude oil prices, the pressure to convert to natural gas has also dropped. Utilization of natural gas by customers with the ability to switch between natural gas and oil is also driven by the relative prices of gas and oil.

Q. Please describe how the Company has accounted for the effects of weather variations in the historic data inputs to its 2016 Gas Forecast.

A. In preparing the 2016 Gas Forecast, the Company used its monthly customer billing data (volume and number of customers) for the period August 2010 through February 2016 to forecast the number of customers and use-per-customer (the quotient of the division of

volume and number of customers) for each of the rate groups it analyzes. Weather, particularly heating degree days, plays the dominant role in modeling the use-per-customer behavior of its customers under the wide range of weather observed in the historical period. The Company's forecast then applies its normalized heating degree days as the basis of its forecast of use-per-customer under normal weather conditions.

Q. Please compare how the 2015/2016 Forecast compares to the actual billings weather normalized for the same period.

A. According to the Company's most recent analysis, where it normalized its actual billing data for November 2015 – May 2016 and June 2015 – October 2015, actual normalized sales were 38,831,364 MMBtu. The Company's normalized forecast for November 2015 – October 2016 (as listed in Table 3, above) was 39,897,041 MMBtu. Actual normalized sales were 2.7 percent lower than forecast.

Q. Please describe how the Company has addressed the effects of colder than normal weather on the development of its Design-Winter and Design-Day requirements.

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

design-year standard for planning purposes to identify the amount of seasonal supplies of natural gas that will be required to provide continuous service under all reasonable weather conditions. The Company establishes its design standards using a three-step process. First, the Company performs statistical analyses of the coldest days and of the annual degree days recorded over a historical period. Second, the Company conducts cost-benefit analyses to evaluate the cost of maintaining the resources necessary to meet design-level demand versus the cost to customers of experiencing service curtailments. Third, the Company identifies design standards that would maintain reliability at the lowest cost.

Q. In last year's GCR filing, Docket No. 4576, the Division's consultant, Bruce Oliver, identified certain concerns regarding the reasonableness of the Company's gas forecast in his pre-filed direct testimony and surrebuttal testimony. Please describe the efforts the Company and the Division have made to address those concerns.

A. The Company has responded to discovery from the Division regarding its 10-year gas forecast as part of the Gas Long-Range Plan in Docket No. 4608. The Company is in the process of completing its remaining responses to the Division's second set of data requests in that docket.

Q. Does this conclude your direct prefiled testimony in this proceeding?

A. Yes, it does.

Attachments of
Theodore E. Poe, Jr.

Attachments of Theodore Poe, Jr.

Attachment TEP-1	National Grid RI Retail Volume Forecast 2016Q2 vs. 2015Q2 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2016Q2 vs. 2015Q2 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2016Q2 vs. 2015Q2 Forecast

Attachment TEP-1

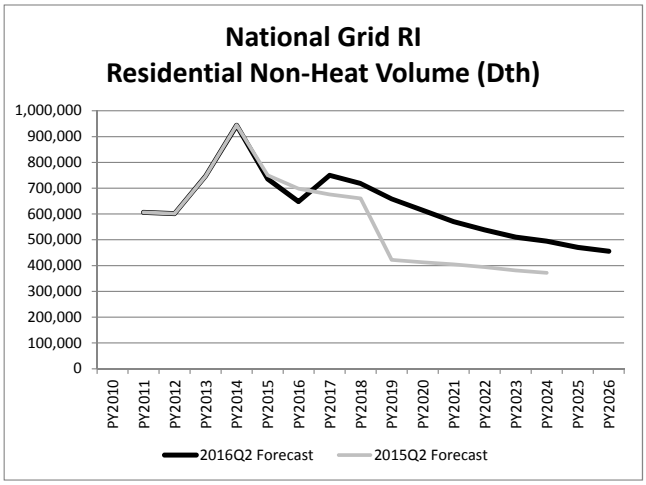
Attachment TEP-1	National Grid RI Retail Volume Forecast 2016Q2 vs. 2015Q2 Forecast

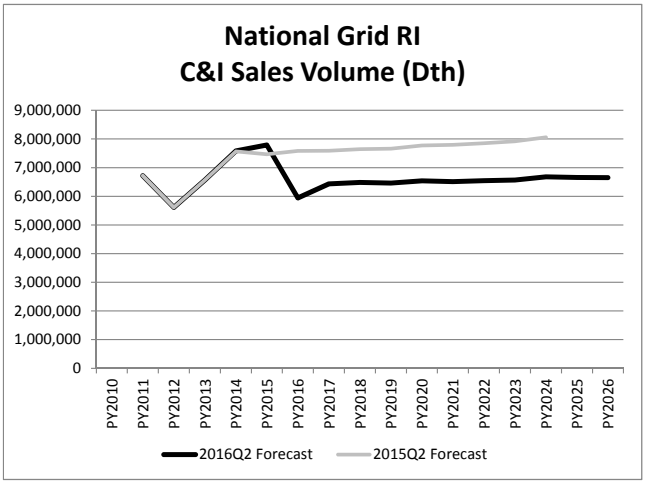
2016Q2 National Grid RI Volume Forecast (Dth)
Planning Year (Nov-Oct)

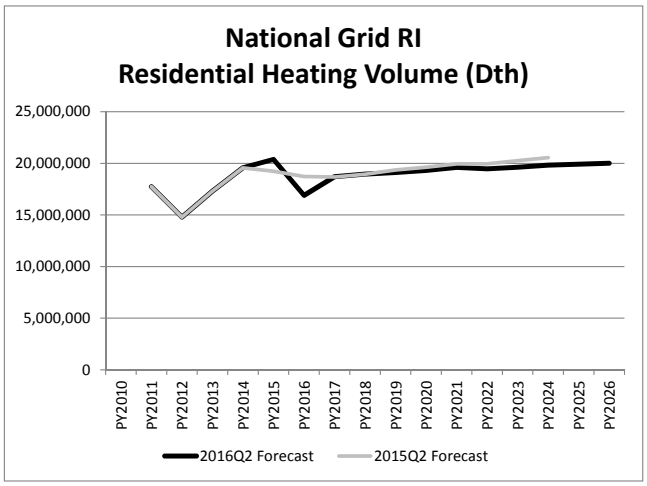
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2010	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2011	606,350	17,738,246	6,716,761	7,690,163	2,569,158	35,320,677	2,205,233	37,525,910
PY2012	601,399	14,783,554	5,615,278	7,616,170	2,334,007	30,950,409	2,169,927	33,120,335
PY2013	746,883	17,315,410	6,567,764	8,293,544	3,062,467	35,986,068	1,985,725	37,971,793
PY2014	944,026	19,572,368	7,584,774	8,575,328	3,575,442	40,251,940	1,734,538	41,986,478
PY2015	736,095	20,380,961	7,788,803	9,481,996	3,742,843	42,130,698	1,736,206	43,866,904
PY2016	648,129	16,900,136	5,943,030	9,015,067	3,770,922	36,277,283	1,789,821	38,067,104
PY2017	749,942	18,714,342	6,431,813	9,229,341	4,221,901	39,347,340	1,781,012	41,128,352
PY2018	718,188	18,961,056	6,486,029	9,308,909	4,354,124	39,828,305	1,781,012	41,609,317
PY2019	658,501	19,111,356	6,460,048	9,327,939	4,427,918	39,985,762	1,780,216	41,765,978
PY2020	614,499	19,315,886	6,538,238	9,358,769	4,543,770	40,371,162	1,785,689	42,156,852
PY2021	570,129	19,604,633	6,514,916	9,297,261	4,616,023	40,602,962	1,781,012	42,383,974
PY2022	538,315	19,467,566	6,545,385	9,299,720	4,693,641	40,544,627	1,781,012	42,325,639
PY2023	510,264	19,622,568	6,570,383	9,310,050	4,796,941	40,810,207	1,780,216	42,590,422
PY2024	494,431	19,822,007	6,680,411	9,371,636	4,925,858	41,294,343	1,785,689	43,080,033
PY2025	470,521	19,924,270	6,656,113	9,344,749	4,993,435	41,389,088	1,781,012	43,170,100
PY2026	455,851	20,015,444	6,649,840	9,343,039	5,089,656	41,553,830	1,781,012	43,334,842
PY22/PY17	-6.4%	0.8%	0.4%	0.2%	2.1%	0.6%	0.0%	0.6%

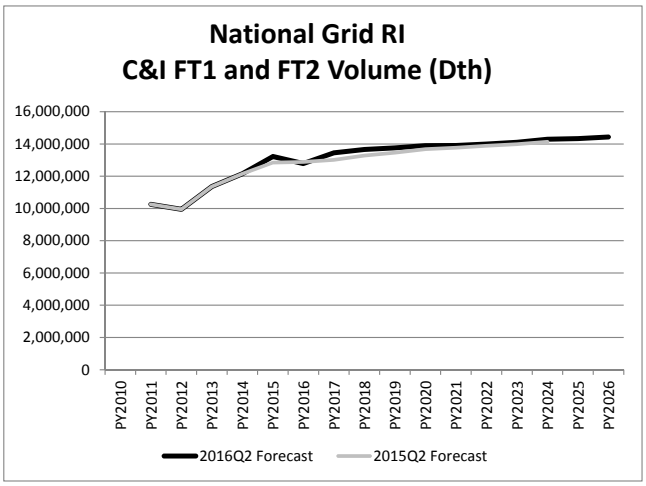
2015Q2 National Grid RI Volume Forecast (Dth)
Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2010	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2011	606,284	17,738,178	6,716,761	7,686,937	2,569,158	35,317,318	2,205,233	37,522,552
PY2012	601,368	14,783,019	5,615,187	7,615,966	2,334,007	30,949,548	2,166,928	33,116,476
PY2013	746,785	17,312,908	6,567,199	8,289,372	3,065,693	35,981,958	1,985,705	37,967,663
PY2014	944,542	19,566,786	7,566,344	8,580,148	3,573,689	40,231,510	1,734,551	41,966,061
PY2015	750,441	19,232,763	7,465,120	9,277,579	3,569,472	40,295,374	1,441,551	41,736,925
PY2016	698,046	18,726,158	7,585,648	9,178,080	3,709,110	39,897,042	1,370,782	41,267,824
PY2017	675,611	18,679,655	7,589,183	9,189,939	3,829,196	39,963,583	1,350,252	41,313,835
PY2018	660,397	18,939,313	7,645,366	9,307,951	3,974,252	40,527,280	1,345,649	41,872,929
PY2019	422,119	19,362,006	7,663,155	9,373,492	4,089,445	40,910,217	1,331,199	42,241,416
PY2020	412,921	19,630,693	7,774,591	9,433,062	4,242,808	41,494,074	1,285,568	42,779,642
PY2021	404,970	19,942,767	7,793,685	9,406,458	4,363,990	41,911,870	1,290,748	43,202,618
PY2022	393,973	19,947,096	7,851,507	9,437,427	4,455,935	42,085,938	1,248,626	43,334,564
PY2023	381,502	20,258,819	7,920,105	9,411,845	4,580,930	42,553,201	1,231,490	43,784,691
PY2024	372,131	20,548,654	8,058,310	9,438,739	4,702,993	43,120,828	1,153,579	44,274,407
PY2025	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2026	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY21/PY16	-10.3%	1.3%	0.5%	0.5%	3.3%	1.0%	-1.2%	0.9%


National Grid RI
Residential Non-Heat Volume (Dth)
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
C&I Sales Volume (Dth)
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
Residential Heating Volume (Dth)
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
C&I FT1 and FT2 Volume (Dth)
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast

Attachment TEP-2

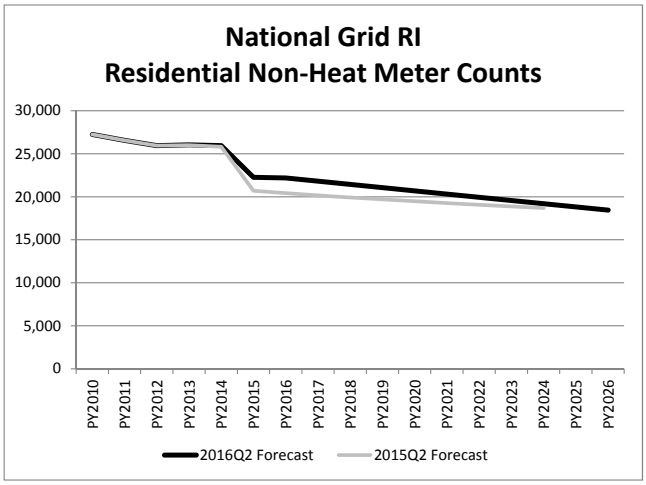
Attachment TEP-2 National Grid RI Retail Meter Count Forecast
2016Q2 vs. 2015Q2 Forecast

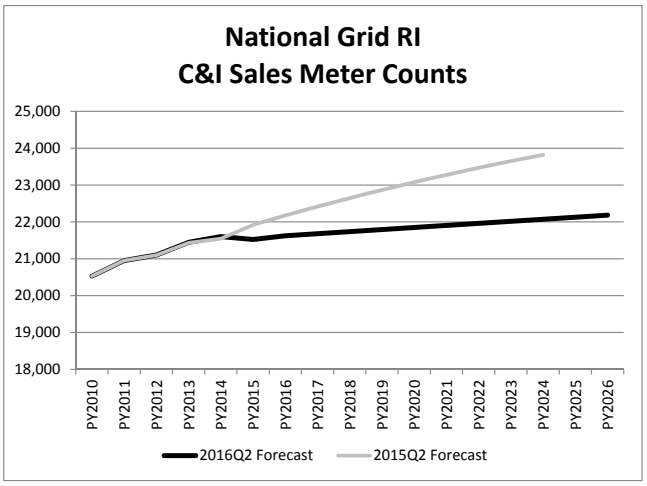
2016Q2 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2010	27,256	190,672	20,530	728	1,094	240,280	26	240,306
PY2011	26,570	196,413	20,949	747	1,244	245,923	26	245,949
PY2012	25,955	200,461	21,102	736	1,412	249,666	25	249,691
PY2013	26,040	204,511	21,445	723	1,615	254,334	20	254,354
PY2014	25,951	206,515	21,600	703	1,662	256,431	16	256,447
PY2015	22,274	212,670	21,522	690	1,843	258,999	12	259,011
PY2016	22,188	212,848	21,625	678	2,050	259,389	12	259,401
PY2017	21,814	215,319	21,680	673	2,117	261,603	12	261,615
PY2018	21,440	217,575	21,736	666	2,184	263,601	12	263,613
PY2019	21,066	219,651	21,792	653	2,249	265,411	12	265,423
PY2020	20,692	221,574	21,848	643	2,316	267,073	12	267,085
PY2021	20,318	223,365	21,904	636	2,380	268,603	12	268,615
PY2022	19,944	225,040	21,960	631	2,445	270,020	12	270,032
PY2023	19,570	226,614	22,017	627	2,511	271,339	12	271,351
PY2024	19,196	228,099	22,072	624	2,575	272,566	12	272,578
PY2025	18,822	229,503	22,128	620	2,640	273,713	12	273,725
PY2026	18,448	231,061	22,183	617	2,705	275,014	12	275,026
PY22/PY17	-1.8%	0.9%	0.3%	-1.3%	2.9%	0.6%	0.0%	0.6%

2015Q2 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2010	27,255	190,671	20,530	728	1,094	240,278	26	240,304
PY2011	26,569	196,412	20,949	747	1,244	245,921	26	245,947
PY2012	25,944	200,453	21,098	736	1,412	249,643	25	249,668
PY2013	26,002	204,461	21,432	723	1,614	254,232	20	254,252
PY2014	25,827	206,209	21,547	700	1,659	255,942	16	255,958
PY2015	20,703	216,434	21,917	687	1,836	261,577	9	261,586
PY2016	20,428	218,678	22,174	690	1,904	263,874	9	263,883
PY2017	20,169	220,909	22,416	689	1,965	266,148	9	266,157
PY2018	19,929	222,687	22,648	690	2,019	267,973	9	267,982
PY2019	19,700	225,696	22,870	692	2,069	271,027	8	271,035
PY2020	19,483	228,696	23,079	692	2,112	274,062	8	274,070
PY2021	19,275	231,690	23,280	687	2,150	277,082	7	277,089
PY2022	19,074	234,677	23,469	685	2,183	280,088	7	280,095
PY2023	18,881	237,660	23,651	683	2,211	283,086	6	283,092
PY2024	18,694	240,638	23,821	681	2,232	286,066	6	286,072
PY2025	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2026	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY21/PY16	-1.2%	1.2%	1.0%	-0.1%	2.5%	1.0%	-4.9%	1.0%


National Grid RI
Residential Non-Heat Meter Counts
30,000
25,000
20,000
15,000
10,000
5,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
C&I Sales Meter Counts
25,000
24,000
23,000
22,000
21,000
20,000
19,000
18,000
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
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PY2023
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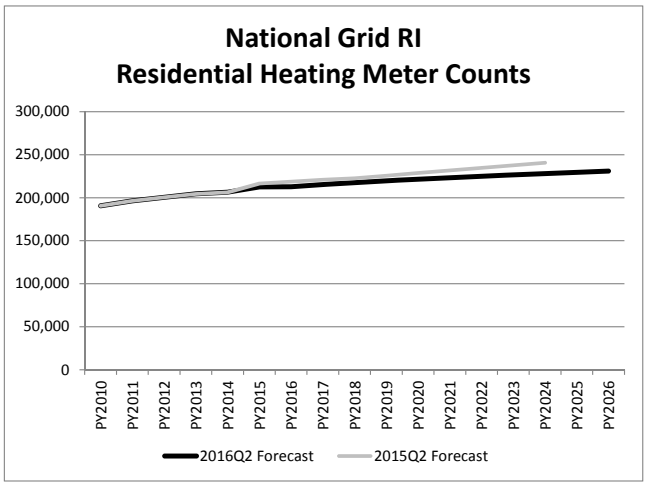
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
Residential Heating Meter Counts
300,000
250,000
200,000
150,000
100,000
50,000
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
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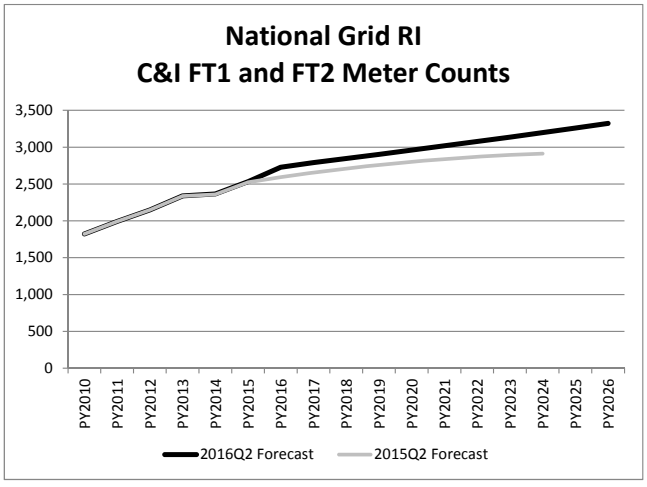
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
C&I FT1 and FT2 Meter Counts
3,500
3,000
2,500
2,000
1,500
1,000
500
0
PY2010
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2016Q2 Forecast
2015Q2 Forecast

Attachment TEP-3

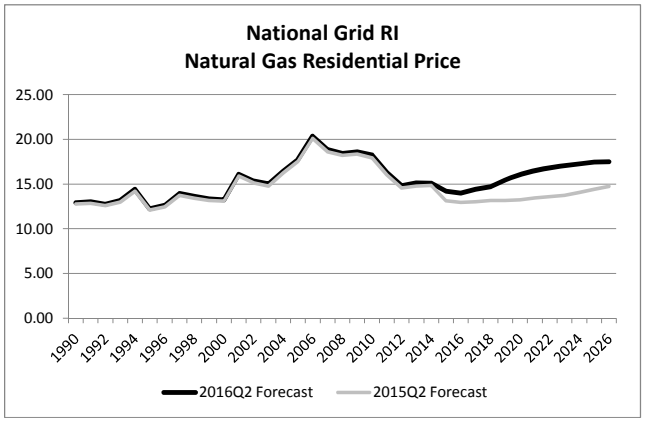
Attachment TEP-3 National Grid RI Economic Forecast
2016Q2 vs. 2015Q2 Forecast

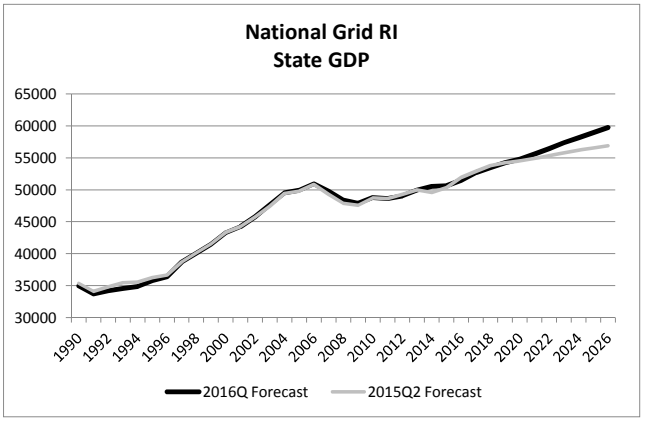
2016Q2 National Grid RI Economic Data
(Prices in 2016 $/Dth)

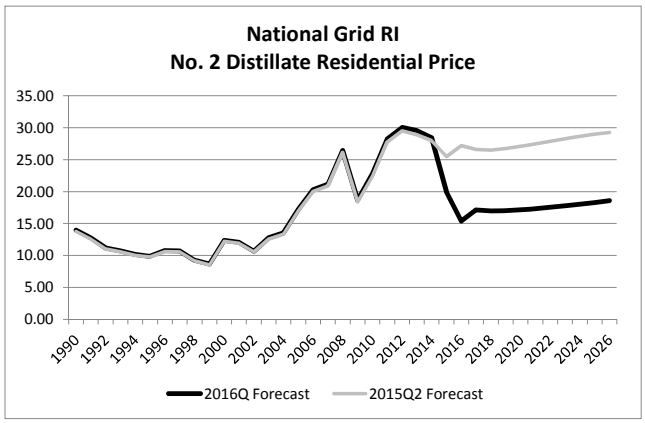
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	GORR	GDP (2009 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	12.92	13.97	0.92	34954	378.930	454.220
1991	13.03	12.74	1.02	33698	381.950	424.280
1992	12.75	11.18	1.14	34189	383.960	424.050
1993	13.18	10.72	1.23	34572	386.210	429.930
1994	14.40	10.15	1.42	34880	387.830	434.210
1995	12.24	9.86	1.24	35782	389.540	439.120
1996	12.61	10.76	1.17	36395	392.350	440.770
1997	13.94	10.71	1.30	38701	395.410	450.060
1998	13.62	9.28	1.47	40071	399.000	457.950
1999	13.35	8.66	1.54	41461	403.950	465.500
2000	13.22	12.35	1.07	43266	409.320	476.910
2001	16.08	12.06	1.33	44212	412.350	478.510
2002	15.33	10.69	1.43	45754	416.220	479.430
2003	15.00	12.75	1.18	47670	418.660	484.280
2004	16.44	13.51	1.22	49526	420.250	488.480
2005	17.75	17.23	1.03	49923	417.950	491.120
2006	20.36	20.25	1.01	50931	416.260	492.980
2007	18.84	21.12	0.89	49755	414.780	492.020
2008	18.41	26.44	0.70	48381	414.540	481.060
2009	18.61	18.65	1.00	47854	414.460	459.350
2010	18.25	22.78	0.80	48792	414.500	458.000
2011	16.31	28.23	0.58	48650	415.540	460.540
2012	14.82	30.06	0.49	49016	417.070	465.570
2013	15.12	29.53	0.51	49943	417.590	471.620
2014	15.08	28.46	0.53	50544	416.600	477.730
2015	14.19	19.87	0.71	50632	417.340	483.410
2016	13.97	15.35	0.91	51481	419.960	490.100
2017	14.40	17.15	0.84	52695	422.490	496.810
2018	14.70	16.97	0.87	53499	424.280	502.830
2019	15.46	17.02	0.91	54222	425.710	507.250
2020	16.03	17.10	0.94	54792	426.860	508.920
2021	16.52	17.31	0.95	55561	427.540	510.390
2022	16.82	17.53	0.96	56450	428.530	512.830
2023	17.07	17.77	0.96	57327	429.790	515.410
2024	17.24	18.01	0.96	58150	430.720	517.600
2025	17.45	18.27	0.95	58953	431.870	519.820
2026	17.50	18.57	0.94	59761	432.770	522.080
PY22/PY17	3.2%	0.4%	2.7%	1.4%	0.3%	0.6%

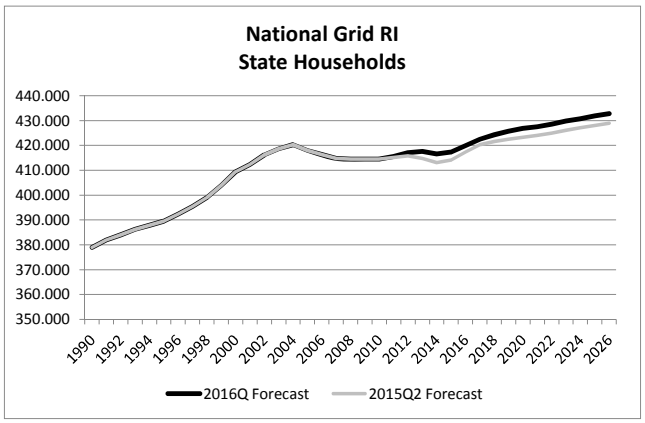
2015Q2 National Grid RI Economic Data
(Prices in 2015 $/Dth)

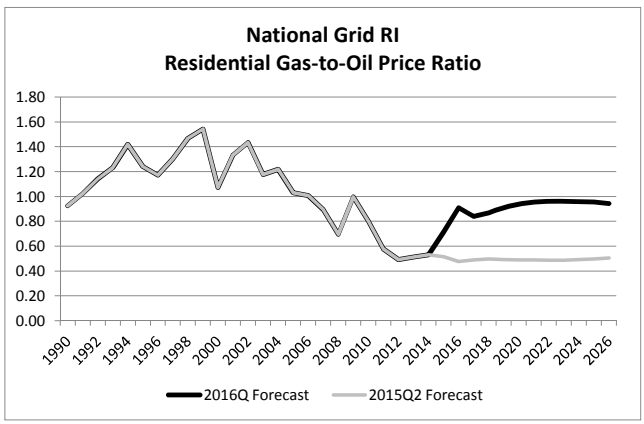
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	GORR	GDP (2005 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	12.75	*13.79*	0.92	35369	378.930	454.225
1991	12.84	*12.56*	1.02	34132	381.950	424.283
1992	12.58	*11.04*	1.14	34819	383.960	424.050
1993	13.00	*10.57*	1.23	35468	386.209	429.925
1994	14.20	*10.00*	1.42	35577	387.830	434.208
1995	12.10	*9.75*	1.24	36253	389.537	439.125
1996	12.43	*10.61*	1.17	36675	392.354	440.767
1997	13.75	*10.56*	1.30	38727	395.405	450.058
1998	13.43	*9.15*	1.47	40110	398.997	457.950
1999	13.16	*8.54*	1.54	41495	403.951	465.500
2000	13.08	*12.21*	1.07	43311	409.315	476.908
2001	15.87	*11.90*	1.33	44211	412.354	478.508
2002	15.13	*10.55*	1.43	45742	416.220	479.433
2003	14.79	*12.56*	1.18	47411	418.655	484.275
2004	16.22	*13.33*	1.22	49414	420.254	488.483
2005	17.53	*17.01*	1.03	49793	417.950	491.125
2006	20.11	*20.00*	1.01	50854	416.261	492.983
2007	18.61	*20.86*	0.89	49279	414.784	492.017
2008	18.20	*26.14*	0.70	47890	414.538	481.058
2009	18.35	*18.39*	1.00	47592	414.455	459.350
2010	17.93	*22.39*	0.80	48719	414.503	457.958
2011	16.03	*27.74*	0.58	48649	415.127	460.592
2012	14.55	*29.51*	0.49	49262	415.732	465.583
2013	14.78	*28.87*	0.51	49962	414.714	471.150
2014	14.83	*28.00*	0.53	49601	413.041	477.250
2015	13.11	25.49	0.51	50351	414.120	484.060
2016	12.94	27.17	0.48	51919	417.272	494.827
2017	13.03	26.56	0.49	52896	420.267	500.395
2018	13.15	26.48	0.50	53804	421.611	503.423
2019	13.16	26.76	0.49	54253	422.455	503.998
2020	13.22	27.09	0.49	54532	423.257	503.623
2021	13.44	27.46	0.49	54892	423.980	503.993
2022	13.58	27.87	0.49	55358	424.905	505.538
2023	13.75	28.24	0.49	55777	426.127	507.386
2024	14.05	28.62	0.49	56165	427.061	508.598
2025	14.42	28.97	0.50	56554	428.073	508.989
2026	14.72	29.22	0.50	56912	428.879	509.130
PY21/PY16	0.8%	0.2%	0.5%	1.1%	0.3%	0.4%

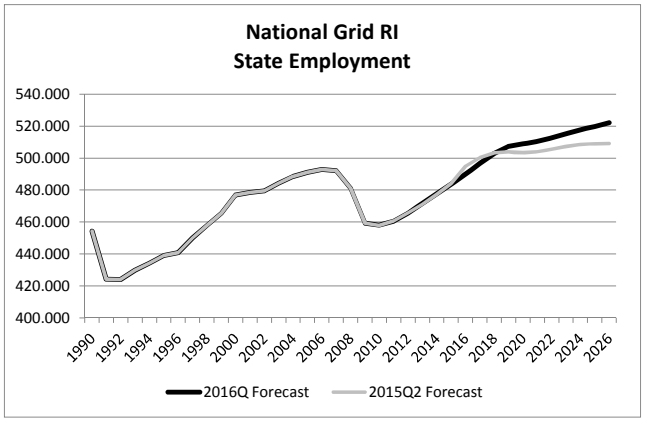

National Grid RI
Natural Gas Residential Price
25.00
20.00
15.00
10.00
5.00
0.00
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
2016Q2 Forecast
2015Q2 Forecast


National Grid RI
State GDP
65000
60000
55000
50000
45000
40000
35000
30000
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
2016Q Forecast
2015Q2 Forecast


National Grid RI
No. 2 Distillate Residential Price
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
2016Q Forecast
2015Q2 Forecast


National Grid RI
State Households
440.000
430.000
420.000
410.000
400.000
390.000
380.000
370.000
360.000
350.000
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
2016Q Forecast
2015Q2 Forecast


National Grid RI
Residential Gas-to-Oil Price Ratio
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
2016Q Forecast
2015Q2 Forecast


National Grid RI
State Employment
540.000
520.000
500.000
480.000
460.000
440.000
420.000
400.000
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026
2016Q Forecast
2015Q2 Forecast