The Narragansett Electric Company
d/b/a National Grid

2019 GAS COST RECOVERY

Testimony and Attachments of:

Elizabeth D. Arangio & Samara A. Jaffe
Michael J. Pini & Ann E. Leary
Theodore E. Poe, Jr.

September 3, 2019

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 4963

Submitted by:
nationalgrid

Filing Letter & Motion

Robinson+Cole

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September 3, 2019

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4963 - 2019 Gas Cost Recovery Filing

Dear Ms. Massaro:

Enclosed please find 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 National Grid's gas tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A. The GCR filing reflects the customer class-specific factors necessary for National Grid to collect sufficient revenues to recover projected gas costs for the period November 1, 2019 through October 31, 2020.

This filing consists of the pre-filed testimony and attachments of Elizabeth D. Arangio, Samara A. Jaffe, Ann E. Leary, Michael J. Pini, Theodore E. Poe, Jr., and John M. Protano. Ms. Arangio and Ms. Jaffe provide joint testimony relative to National Grid's projected gas costs in support of the proposed GCR factors, as well as to modifications to National Grid's gas supply portfolio for the 2019 GCR period. The joint testimony of Mr. Pini and Ms. Leary describes the development of the GCR factors proposed for effect November 1, 2019 and provides a bill impact analysis relative to those proposed factors. Mr. Poe's testimony provides support for the underlying wholesale and retail forecasts that National Grid uses to estimate gas costs in this filing. Mr. Protano's testimony discusses the results of the Gas Procurement Incentive Plan for the period April 1, 2018 through March 31, 2019. Mr. Protano also discusses the results of the Natural Gas Portfolio Management Plan for the period April 1, 2018 through March 31, 2019.

As described in the joint testimony of Mr. Pini and Ms. Leary, based on the GCR factors proposed for effect November 1, 2019 through October 31, 2020, an average residential heating

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

customer using 845 therms per year will experience a total bill decrease of approximately $147.58, or a 10.9 percent decrease from the existing rates. This decrease of $147.58 is comprised of a decrease of $146.95 in the GCR-related factors; an increase of $3.80 in the Distribution Adjustment Charge-related factors, filed on August 1, 2019 and supplemented today under separate cover in Docket No. 4955; and a decrease of $4.43 in Gross Earnings Tax.

This filing also contains a Request for Protective Treatment of Confidential Information in accordance with Rule 810-RICR-00-00-1.3(H) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain confidential gas-cost pricing information, commercial contract terms and forecasts, which are provided in Attachments EDA/SAJ-1 and EDA/SAJ-8 to the joint testimony of Ms. Arangio and Ms. Jaffe and in Attachments MJP/AEL-1, MJP/AEL-2, and MJP/AEL-5 to the joint testimony of Mr. Pini and Ms. Leary.

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

Thank you for your attention to this matter. If you have any questions, please contact me at 401-709-3359.

Very truly yours,

Steven J. Boyajian

Enclosures

cc: Docket 4963 Service List
Leo Wold, Esq.
Al Mancini, Division
John Bell, Division

Docket No. 4963 – National Grid – 2019 Annual Gas Cost Recovery Filing (GCR) - Service List as of 8/30/2019

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2019	)	Docket No. 4963

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

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

I. BACKGROUND

On September 3, 2019, the Company submitted its 2019 Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. The GCR filing includes confidential gas cost pricing information and contract terms, which are provided in (1) Attachments EDA/SAJ-1, EDA/SAJ-8, EDA/SAJ-9, EDA/SAJ-10, and EDA/SAJ-11 to the pre-filed joint testimony of Elizabeth D. Arangio and Samara A. Jaffe; and (2) Attachments MJP/AEL-1, MJP/AEL-2, and MJP/AEL-5 to the pre-filed joint direct testimony of Michael J. Pini and Ann E. Leary. In

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

accordance with Rule 1.3(H)(3), National Grid has provided a redacted public version of the GCR filing, as well as an unredacted, confidential version.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the gas cost pricing information and contract terms contained in the following: (1) Attachments EDA/SAJ-1, EDA/SAJ-8, EDA/SAJ-9, EDA/SAJ-10, and EDA/SAJ-11 to Ms. Arangio and Ms. Jaffe's joint testimony; and (2) Attachments MJP/AEL-1, MJP/AEL-2, and MJP/AEL-5 to Mr. Pini and Ms. Leary's joint testimony.

II. LEGAL STANDARD

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

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

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

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

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

III. BASIS FOR CONFIDENTIALITY

The gas cost pricing information and confidential contract terms – which are provided in Attachments EDA/SAJ-1, EDA/SAJ-8, EDA/SAJ-9, EDA/SAJ-10, and EDA/SAJ-11 to Ms. Arangio and Ms. Jaffe's joint testimony, and Attachments MJP/AEL-1, MJP/AEL-2, and MJP/AEL-5 to Mr. Pini and Ms. Leary's joint testimony – are confidential and privileged information of the type that National Grid would not ordinarily make public. As such, the information should be protected from public disclosure. Public disclosure of such information could impair National Grid's ability to obtain advantageous pricing or other terms in the future, thereby causing substantial competitive harm. Accordingly, National Grid is providing the information on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

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

[SIGNATURE ON NEXT PAGE]

Respectfully submitted,

THE NARRAGANSETT ELECTRIC
COMPANY d/b/a NATIONAL GRID
By its attorney,

____
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Dated: September 3, 2019

JOINT DIRECT TESTIMONY

OF

ELIZABETH D. ARANGIO

AND

SAMARA A. JAFFE

September 3, 2019

Table of Contents

I. Introduction

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

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

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

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

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

A. I graduated from 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 assumed the added responsibility for the gas resource portfolios in upstate New York and Rhode Island. In August 2018, I assumed the added responsibility for all of National Grid's gas Customer Choice programs.

Q. Are you a member of any professional organizations?

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

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

A. Yes. I have testified before the PUC on numerous occasions, most recently in support of the Company's 2018 GCR filing in Docket No. 4872. I have also testified numerous times before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission. In addition, I have presented information to the State of New York Department of Public Service.

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

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

Q. Please state your business position and responsibilities.

A. I am the Lead Program Manager of Gas Contracting, Compliance and Hedging for National Grid USA Service Company, Inc. In this position I am responsible for the acquisition of long-term gas supply and pipeline capacity; gas contract management; intervention in proceedings before the Federal Energy Regulatory Commission ("FERC"); and, compliance with FERC regulations in connection with National Grid's gas trading activities for National Grid's gas distribution companies in Massachusetts, Rhode Island, and New York including Boston Gas and Colonial Gas. In this proceeding, I am providing testimony on behalf of the Company.

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

A. I graduated from the State University of New York at Buffalo in 2006 with a Bachelor of Arts degree in Chemistry. In 2012 I graduated from Touro Law Center with a Juris Doctor. In 2016 I graduated from Dowling Institute with a Master of Business Administration. I joined KeySpan Gas East Corporation in 2007 as a Natural Gas Scheduler in KeySpan's Energy Procurement area with responsibility for scheduling natural gas on interstate pipelines utilized by the company to meet the requirements of its wholesale firm gas customers. After graduating from Touro Law Center in 2012, I accepted my current position as Program Manager for National Grid USA Service Company, Inc.'s Energy Procurement Gas Contracting and Compliance group.

Q. Have you previously testified in regulatory proceedings?

A. Although I have not previously submitted direct testimony on behalf of the Company to the PUC, I have sponsored several responses to information requests in recent proceedings. I have also testified at the Massachusetts Department of Public Utilities (DPU) on behalf of National Grid's Boston Gas Company and Colonial Gas portfolios, most recently in D.P.U. 19-26 wherein the DPU approved the Colonial Gas's asset management arrangement with Emera Energy Services, Inc. I also testified before the DPU in D.P.U. 18-104 wherein the DPU approved the Company's long-term supply agreements with Constellation LNG, LLC, as well as in D.P.U. 17-174 wherein the DPU approved the Company's firm transportation agreements with Tennessee and Portland Natural Gas Transmission Systems.

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

A. Our testimony provides support for the estimated gas costs, assignments of pipeline capacity to Marketers, and other items relating to the Company's proposed 2019-20 GCR factors. In addition, our testimony discusses modifications that the Company has made to its portfolio for the 2019-20 GCR period.

Q. Are you sponsoring attachments to your testimony?

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

Attachment EDA/SAJ-1	Projected Gas Costs and Assignment of Pipeline Capacity – **CONFIDENTIAL Information**
Attachment EDA/SAJ-2	NYMEX Strip Comparison
Attachment EDA/SAJ-3	FT-2 Operational Parameters
Attachment EDA/SAJ-4	FT-2 Storage Variable Costs
Attachment EDA/SAJ-5	RFPs for PXP Phases I & II
Attachment EDA/SAJ-6	RFP for AMA Dracut to Citygate
Attachment EDA/SAJ-7	RFP for Citygate Deliveries
Attachment EDA/SAJ-8	Incremental Portable LNG Storage and Vaporization **CONFIDENTIAL Information**
Attachment EDA/SAJ-9	RFP for AMA Dawn to Tennessee Zone 6
Attachment EDA/SAJ-10	RFP for AMA TCo Broadrun to Hanover
Attachment EDA/SAJ-11	Tennessee FT-A Dracut to Cranston

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 New York Mercantile Exchange (NYMEX) strip as of the close of trading on August 1, 2019. The GCR factors also reflect storage and inventory costs as of July 1, 2019, as well as the projected cost of purchasing gas through the remainder of the injection season. Attachment EDA/SAJ-1 page 1 of 21 provides a summary of gas costs by major cost categories and pages 2 of 21 through 12 of 21 shows the cost detail by supply source.

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/SAJ-2 is a graph that compares NYMEX pricing from August 2, 2018 utilized in last year's GCR filing to NYMEX pricing from August 1, 2019 used in this current filing. On average, the August 1, 2019 NYMEX strip is $0.453, or 15.3 percent, lower compared to the August 2, 2018 NYMEX strip during the peak season of November through March. During the off-peak season of April through October, the August 1, 2019 NYMEX strip is on average $0.222, or 8.5 percent, lower compared to the August 2, 2018 NYMEX strip. Overall, the August 1, 2019 NYMEX strip is an average of $0.318, or 11.5 percent, lower compared to the August 2, 2018 NYMEX strip.

Q. What design day, design heating season, and design year load is the Company planning for in 2019-20 as compared to last year's volumes?

A. A comparison of the design day, design heating season, and design year load forecasts for 2018-19 and 2019-20 is provided in the table below.

2018/2019 and 2019/2020 Design Forecast Comparison

Design Day	2018/19 Forecast	2019/20 Forecast	Delta	Delta %
Total Design Day (Sales + Transportation)	390,227	388,746	(1,481)	-0.4%
Design Day - Sales	336,289	323,811	(12,478)	-3.7%
Design Day - Transportation	53,938	64,935	10,997	20.4%

Design Heating Season (November - March)	2018/19 Forecast	2019/20 Forecast	Delta	Delta %
Total Design Heating Season (Sales + Transportation)	29,676,936	29,822,626	145,690	0.5%
Design Heating Season - Sales	24,782,750	23,842,974	(939,776)	-3.8%
Design Heating Season - Transportation	4,894,186	5,979,652	1,085,466	22.2%

Design Year	2018/19 Forecast	2019/20 Forecast	Delta	Delta %
Total Design Year (Sales + Transportation)	41,521,561	41,409,931	(111,630)	-0.3%
Design Year - Sales	33,532,200	31,975,988	(1,556,212)	-4.6%
Design Year - Transportation	7,989,361	9,433,943	1,444,582	18.1%

The forecast filed in Docket No. 4872 against this year's forecast.
Volumes include only customers utilizing Company assets.
Volume are in dekatherms (Dth)

Q. Did the Company perform a cold snap analysis for the 2019-20?

A. Yes. Following the cold snap experienced in the 2017-18 winter season, the Company reviewed a cold snap scenario, in addition to design day and design year scenarios for the upcoming winter season, as part of its annual portfolio planning process. The cold snap analysis is set forth in the Company's Long-Range Resource and Requirements Plan for the Forecast Period 2019/20 to 2023/24 dated July 2, 2019 as filed with the Rhode Island Division of Public Utilities and Carriers (the LRP).

Q. Has the Company made other changes to its forecasting and planning processes that impact costs to customers? Please explain why any changes were made.

A. Yes. The Company is planning to meet peak hour requirements in addition to design day, design year, and cold snap requirements.

On January 29, 2019, Algonquin Gas Transmission, LLC (AGT), one of the interstate pipeline companies that serves the Company, notified the Company (and all AGT customers served by AGT's G Lateral pipeline) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes to calculated hourly flow limits at each take station. Under the Company's contracts with AGT, those calculated hourly flow limits are either 1/24th or 6% of the daily MDQ under each contract. The total calculated hourly flow limits for each take station are then equal to the combined calculated hourly flow limit for all contracts providing deliveries to each take station. Historically, AGT has not imposed any requirements that its customers manage the calculated hourly flow limits, nor has AGT restricted the Company’s ability to balance its overall takes across all take stations. The January 29, 2019 notice expired on April 1, 2019. However, the Company reasonably expects that AGT may issue a similar notice in the future, or even issue the types of orders described in the January 29, 2019 notice without first issuing another warning. Accordingly, the Company is making planning decisions to be able to comply with any such future orders. Because the Company’s peak hour is greater than the daily 1/24th and 6% combination, the Company will now need to ensure that it has sufficient deliverability to meet the peak hour requirements of its customers.

Q. How is the Company determining peak hour requirements and what are the requirements for the 2019/20 gas year?

A. Once the design day sendout requirement is established, the Company converts this sendout to a peak hour based on a 5% peak-hour factor (i.e. the peak hour requirement represents 1/20th of the peak day requirement). The Company then applies the peak-hour requirement to its Synergi network analysis modeling software by means of growth factors generated from the zonal (i.e., zip code) forecast. The resulting peak-hour Synergi models are used to perform various analyses necessary for distribution system operations (e.g., regulator pressure settings, LNG requirements) and capital planning.

The table below shows the hourly imbalance at each take station for the first year (2019/20) and last year (2023/24) of the forecast period. This same chart was included in the Company's July 2, 2019 LRP, but has been updated to include corrected volumes at the Dey Street and Cranston meters.

				2019/20			2023/24		
Pipeline/LNG	**Lateral**	**Take Station**	**Meter No.**	**Total Supply Deliveries Company & Marketers (Dth/hr)**	**Total Firm Peak Hour Model Flow (DTH/hr)**	**Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)**	**Total Supply Deliveries Company & Marketers (Dth/hr)**	**Total Firm Peak Hour Model Flow (DTH/hr)**	**Total Firm Peak Hour Balance (-) = Shortfall (+) = Surplus (DTH/hr)**
AGT	G	Barrington	00064	0	0	0	0	0	0
AGT	G	Warren	00012	811	794	17	770	794	-24
AGT	G	Burrillville	00044	0	30	-30	0	31	-31
AGT	G	Crary St	00842	0	2,060	-2,060	0	2,060	-2,060
AGT	G	Dey St	00004	5,540	2,077	3,463	5,704	2,091	3,613
AGT	G	Cumberland	00083	42	49	-8	42	49	-8
AGT	G	Portsmouth	00013	1,045	1,210	-164	1,045	1,231	-186
AGT	G	Tiverton	00033	56	68	-12	56	70	-14
AGT	G	E Providence	00010	1,698	2,221	-523	1,698	2,342	-644
AGT	E	Westerly	00008	144	112	32	144	114	30
AGT		Montville	00059	208	233	-25	208	246	-38
TGP	Cranston	Cranston	420750	2,794	2,107	687	4,082	3,151	931
TGP	Cranston	Lincoln	420758	1,283	1,053	230	1,283	1,054	230
TGP	Cranston	Smithfield	420910	450	1,608	-1,158	450	1,638	-1,188
TGP		Cumberland	420135	1,343	1,823	-480	1,343	1,832	-489
LNG		Exeter		1,000	1,000	0	1,000	1,000	0
LNG (incl. KLNG)		Providence		3,958	4,750	-792	3,958	4,750	-792
LNG		Cumberland		750	750	0	750	750	0
			Total:	21,122	21,944	-821	22,532	23,202	-670

Q. How are projected gas costs calculated?

A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT® model to perform a dispatch optimization of the portfolio of gas supply, pipeline transportation, underground storage, and peaking supplies. SENDOUT® allows the Company to determine the optimal dispatch of its existing resources subject to contractual and operating constraints to minimize the cost of supply over the year. The pricing of various pipeline services is based directly on the pipeline tariffs and the rates in effect as of August 1, 2019. 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.

The Supply Fixed Cost Component includes all fixed costs related to the purchase, storage, or delivery of firm gas, including pipeline and supplier fixed reservation costs and demand charges. The Company will incur Supply Fixed Cost Components in consideration of a right, but not the obligation, to call on transportation and/or supply needed to meet the supply requirements of its customers.

The Supply Variable Cost Component includes all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense incurred to transport supplies, transportation fees, storage commodity costs, taxes on storage commodity and other gas storage expense incurred to transport supplies, and inventory commodity costs.

A summary of gas costs included in the GCR and disaggregated into these cost components by month for the period November 2019 through October 2020 is shown in Attachment EDA/SAJ-1 page 1 of 21.

Q. Please describe Attachment EDA/SAJ-1, Pages 2 through 12.

A. Attachment EDA/SAJ-1 pages 2 through 12 shows the supporting detail for gas costs included in the filing for the period November 2019 through October 2020. Pages 2 through 4 show the detail pertaining Commodity costs listed by supply source, pages 5 through 8 show the variable and fixed costs detail for both transportation and storage, and page 9 is the detail supporting the supplier fixed costs. Page 10 is a summary of the projected underground storage and LNG inventories and pages 11 through 12 show the optimized, forecasted sendout by supply source under normal weather conditions from the SENDOUT® model, as well as the detailed makeup of supply by pipeline source, storage contract, and peaking facility/contract. Page 11 shows the forecasted volumes at the receipt or purchase point while page 12 shows the forecasted volumes at the point of delivery after all pipeline fuel is accounted for. The pricing included in this filing reflects both actual pricing and indicative pricing and terms based on the Company’s current contracts with suppliers. Charges for the supply contracts have been redacted in the public version of the filing in order to comply with confidentiality terms in the Company's agreements with its suppliers.

Q. How do the gas costs presented in the Company's Gas Cost Recovery filing compare with those submitted to the Division in the Company's most recent Long Range Plan dated July 2, 2019?

A. Total gas costs are $11.1 million lower in this GCR filing compared with the costs forecasted in the Company's LRP. The differences are summarized in the following table:

Cost Item	Difference in $Millions (GCR value – LRP value)
a. Fixed Costs	$1.0
b. Fixed Cost Credits	$3.4
c. Net Fixed Costs (a-b)	-$2.4
d. Variable Costs	-$3.1
e. NGPMP Credit	$5.7
f. Total Gas Costs (c+d-e)	-$11.1

Q. Please summarize major drivers for the differences in costs.

A. While fixed costs remain relatively consistent between the LRP and GCR filing, there was a $2.8 million increase in the fixed costs of the Company's transportation contracts primarily resulting from increased rates proposed by Texas Eastern Transmission Co. (TETCO); TETCO and its customers, including the Company, as well as the FERC, are currently in settlement discussions related to the proposed rate increase. This increase was offset by a $3 million decrease in the Company's supplier fixed costs. This decrease is primarily due to a decrease in fixed costs associated with supplies purchased at Dracut since the Company has pursued an Asset Management Arrangement (AMA) for its capacity from Dracut to the city gate in lieu of a supply deal at Dracut. The Company did not include an estimate of AMA credits in the LRP. However, the Company now estimates this credit to be $1.9 million. Marketer capacity release credits have also increased by $1.5 million due to the company transitioning Everett and Dracut pipeline resources to peaking resources.

Total variable costs decreased by $3.1 million from the LRP to the GCR, due primarily to a decrease in gas commodity costs. This drop is largely the result of a decrease in forward prices; the average November 2019 through March 2020 NYMEX forward curve decreased by $0.17 per dekatherm or 6% and by $0.14 per dekatherm or 5% over the full 2019/20 gas year.

The Company did not include an estimate of NGPMP credits in the LRP, which it is estimating at $5.7 million in connection with this GCR filing. This accounts for approximately 49% of the gas cost decrease from the forecast in the July 2, 2019 LRP as compared to this GCR filing.

III. Gas Supply Portfolio

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

A. The Company's portfolio continues to be well positioned to take advantage of opportunities presented by the development of the Marcellus basin utilizing its economically-priced market area transportation on existing long and short-haul capacity. On most days, the Company is able to purchase less expensive supplies at the TETCO Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company's citygates on the Algonquin Gas Transmission (Algonquin) pipeline, as well as the Tennessee Gas Pipeline Company, LLC (Tennessee) Zone 4 (Zone 4) point using existing pipeline contracts previously used to purchase Gulf of Mexico supplies. The Company can take advantage of these less expensive supplies without incurring any additional fixed costs.

Beginning in the 2018/19 gas year, the Company has increased its position back to Dawn, Ontario to source supplies to feed a significant portion of its TGP capacity from Dracut to the city gate. The diversification offered by this path provides an opportunity to source reasonably priced supplies at Dawn, which provides more liquidity than Dracut.

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

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

<u>Millennium Expansion Project</u>

The Company has contracted for 9,000 Dth per day as part of the Millennium Project for an initial term of fifteen years. This contract was available to the Company beginning January 2019 and went fully into service effective April 1, 2019. The Company's 9,000 Dth per day of Millennium capacity represents half of the Company's AIM Project volume.

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

The Company has entered into a Precedent Agreement for up to 1,780 Dth per day and 380,920 Dth per refill season for a term of fifteen years, commencing upon completion of the necessary facilities. The Northeast Energy project is located in central Massachusetts and has an expected in-service date of April 1, 2020. The Northeast Energy Project will connect to the Tennessee pipeline and allow for the Company to utilize its existing Tennessee capacity to transport volumes from liquid supply basins to the proposed liquefaction facility located in Zone 6. The LNG will be trucked from the facility to the Company's LNG facilities in Rhode Island.

Portland Natural Gas Transmission System (PNGTS) Capacity

Once fully phased in, the addition of the PNGTS capacity will reduce the Company's exposure at Dracut and allow the Company to access up to 29,000 Dth per day from Dawn, Ontario by way of agreements with Union, TransCanada, and PNGTS to deliver firm supplies into Dracut as part of the PXP Project. The PNGTS Agreement will feed into the Company's existing Dracut capacity (29,000 Dth per day). For the 2019/20 heating season, the Company will have access to 25,705 Dth/day on this path.

In order to supply this path, the Company issued several RFPs for AMAs to manage this path. Through the RFP process, the Company was willing to consider AMAs that only required assignment of the Company's capacity on Union and TransCanada to East Hereford, as well as AMAs that included a release of the Company's capacity on Portland for deliveries into the Company's Tennessee capacity at Dracut, MA. Additionally, the Company sought separate AMA transactions for the capacity that is already available under the first phase of the PXP Project and the additional capacity that is anticipated to be in service beginning November 1, 2019. Copies of each of the RFPs are found in Attachment EDA/SAJ-5. Based on the results of the RFP, the Company will maintain the Portland capacity and move forward with AMAs for supplies delivered into East Hereford that will be transported by the Company to its citygates using the Company's Portland and Tennessee contracts. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned Canadian capacity for its own account. In exchange, the Company will receive an asset management fee, which is then fully credited to the customers. The Company is presently negotiating a transaction confirmation to memorialize this transaction.

<u>Incremental Dracut Capacity and Supply</u>

For the 2019/20 heating season, the Company is forecasting an incremental need for capacity in order to meet design hour and design year requirements. The Company has contracted with Tennessee to add incremental capacity of 20,000 dth/day from Dracut, MA to Cranston, RI. This is existing, unsubscribed capacity on Tennessee's system and is available at maximum FT-A tariff rates and does not require any additional construction in order to be available. The Company intends to review the agreement with Tennessee for incremental Dracut capacity with the Division in the upcoming months. Please see Attachment EDA/SAJ-11 for a copy of the agreement.

In order to supply this path, the Company issued an RFP for an AMA to provide supply and manage its capacity from Dracut, MA to the Company's TGP city gate for a term of one year, beginning in November 2019. The RFP requested an MDQ of 22,300 Dth per day which included excess exposure at Dracut, MA from existing transportation capacity in the Company's portfolio. Please see Attachment EDA/SAJ-6 for a copy of the RFP.

Incremental Winter Supplies

On May 23, 2019, the Company issued an RFP for gas supplies delivered to the Company's citygates on either Tennessee or Algonquin by bidders demonstrating that they have either firm capacity to the Company's citygates or providing an explanation of the priority of service that would be utilized to serve the deliveries. As a result of the RFP, the Company is now negotiating a contract for city gate supplies delivered via Algonquin for the 2019/20 through 2022/23 heating seasons. These supplies are backed by firm capacity and are needed to meet forecasted design hour and design season requirements. Please see Attachment EDA/SAJ-7 for a copy of the RFP.

For the 2019/20 heating season, the Company is finalizing the need to contract for winter season supplies to flow on its Tennessee transportation contracts with a receipt point of Everett, MA for the remaining 5,000 dekatherms per day that is not currently provided for under long-term contract. As the costs of these supplies are not yet known, the Company has used an estimate based on historical Everett supply deals.

Incremental Portable LNG Storage and Vaporization Contracts

To support operations at Cumberland for the winter 2018/2019 season, the Company previously entered into an equipment rental and support services agreement with Prometheus Energy Group, Inc. (Prometheus Energy). That agreement included a one-time right to extend for the period commencing December 1, 2019 through and including March 31, 2020. The Company has exercised this extension option for winter 2019/2020.

In addition to the portable operations at Cumberland, the Company is pursuing a multi-year agreement for portable injection services on Aquidneck Island. The Company recently concluded a request for proposals for portable Compressed Natural Gas (CNG) decompression and/or portable LNG vaporization and storage services beginning winter 2019/20 to be staged at the Company's Old Mill Lane location and/or property not owned by the Company and identified by the vendor as part of their proposal. Based on the results of the RFP, the Company is moving forward with a multi-year contract for LNG storage and vaporization services at Old Mill Lane with Prometheus Energy. The Company intends to review the agreement with Prometheus Energy with the Division in the upcoming months. Please see Attachment EDA/SAJ-8 for a copy of the RFP, bid analysis and the final agreement with Prometheus Energy.

Incremental Winter Liquid Volumes (LNG)

In order to support the portable LNG storage operations at Cumberland and Old Mill Lane, the Company will need to pursue a supplemental winter only LNG purchase agreement. The Company may also need to purchase additional winter only liquid should it be determined that the Exeter and NGLNG/Providence LNG facilities will be utilized more actively for balancing purposes during the 2019/20 winter season. As the costs of these supplies are not yet known, the Company has used an estimate based on historical winter LNG refill deals.

Q. How will the Company supply the Dawn capacity path in Ontario, Canada to Tennessee Zone 6 via Iroquois for the 2019-20 year?

A. The Company issued an RFP for an Asset Management Arrangement for a term of one year effective November 1, 2019. The RFP requested a MDQ of 1,000 Dth per day with a monthly option for the Company to elect a baseload quantity and any remaining volumes available as a daily call option during the months of November 2019 through March 2020. These supplies will be delivered directly to the Company’s TGP city gate in Lincoln, RI by the asset manager. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to its customers. On August 17, 2018, the Company selected an offer for asset management services commensurate with the foregoing information and is presently negotiating a transaction confirmation to memorialize the trade. Please see Attachment EDA/SAJ-9 for a copy of the RFP.

Q. How will the Company supply the Columbia Gas Pipeline capacity path originating at Broadrun for the 2019-20 year?

A. The Company issued an RFP for an AMA for a term of one year effective November 1, 2019. The RFP requested a MDQ of 10,000 Dth per day for volumes available as a daily call option during the months of November 2019 through April 2020. These supplies will be delivered to the Company's Algonquin transportation at the Hanover, NJ interconnect. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to its customers. On August 17, 2018, the Company selected an offer for asset management services commensurate with the foregoing information and is presently negotiating a transaction confirmation to memorialize the trade. Please see Attachment EDA/SAJ-10 for a copy of the RFP.

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

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

<u>NGLNG</u>

The Company previously entered into a precedent agreement for a term of 20 years for liquefaction services at NGLNG's currently-existing storage facilities located in Providence, Rhode Island. On October 17, 2018, FERC issued the Order granting a certificate of public convenience and necessity to National Grid LNG LLC in FERC Docket No. CP16-121-000 for the Fields Point Liquefaction Project. NGLNG filed its acceptance of the certificate of public convenience and necessity on October 29, 2018 and the Implementation Plan was filed on November 1, 2018. Based on the timeline to construct and test the facilities, NGLNG expect to begin service of the liquefaction project in April 2021. Once in service, the Company will be able to utilize its existing Algonquin capacity to transport volumes to the NGLNG plant in Providence for liquefaction during the off-peak period.

Northeast Energy

The Company previously entered into a precedent agreement for up to 1,780 Dth per day for a term of 15 years for liquefaction services with Northeast Energy. The Northeast Energy project will be located in central Massachusetts and has an intended in-service date of April 1, 2020. On August 31, 2018, Northeast Energy submitted a petition to the Massachusetts Energy Facilities Siting Board for approval to construct, operate and maintain a new natural gas liquefaction and storage facility in the town of Charlton, MA. In the petition, Northeast Energy included: a description of the project; an analysis of the project need; an analysis of the alternatives to the project and the site selection process; and a review of the project's environmental impacts and proposed mitigation measures and design requirements. Also, on August 31, 2018, Northeast Energy submitted to the Massachusetts Department of Public Utilities a petition for determination that certain zoning exemptions related to the project facilities are reasonably necessary for the convenience or welfare of the public. The docket number assigned to the petition is EFSB-18-04/DPU 18-96. The preliminary project schedule contemplated in Northeast Energy's application estimates a maximum total of 24 months required for the contracted for liquefaction services to be ready for service. This timeline includes allowance for 24 months for engineering and project management services, 18 months for the procurement of long lead items, 12 months for prefabrication of components and 12 months for field construction, commissioning and training. Northeast Energy anticipates being able to compress the schedule and parallel some of the activities by pre-ordering long-lead items and pre-fabricating the equipment to meet an April 2020 in-service date.

IV. Marketer Capacity Paths

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

A. Attachment EDA/SAJ-1, Page 13, shows the paths and corresponding quantities available for assignment to Marketers. In total, the Company has made available 35,258 Dth of capacity per day on seven different pipeline paths.

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

A. The first step in calculating the adjustment charge for each path is calculating the system average cost. The derivation of the weighted average pipeline path cost of $0.8143 per Dth is shown in Attachment EDA/SAJ-1, Page 14. This cost is equal to the sum of the 100 percent load factor fixed cost unit value; the system-average unit variable cost, including basis differential; and one year of the Marketer reconciliation adjustment represented as a 100 percent load factor per-unit cost. The 100 percent load factor fixed cost unit value is $0.9189 per Dth. The system average pipeline unit variable value is a negative-$0.1050 per Dth. The sum of these components results in a weighted average pipeline cost of $0.8139 per Dth. The 100 percent load factor per-unit value of $0.0004 for the Marketer reconciliation adjustment is then added to arrive at the total weighted average pipeline cost of $0.8143 per Dth.

Q. How are the delivered costs for each path released to Marketers developed in Attachment EDA/SAJ-1 pages 15 through 21?

A. The calculations for the delivered cost for each path are similar to those described for the system-average. For illustration, the calculation for the first path, Tennessee Zone 1, consists of a single contract originating in Zone 1 and terminating in Zone 6. Total fixed costs of $2,395,049 and total variable costs of $9,567,632 are shown in the far right column on Page 19 of Attachment EDA/SAJ-1. Commodity gas costs of $8,490,236 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 $0.6907 per Dth at 100 percent load factor, plus the non-gas variable unit cost of $0.3099 per Dth, for a total path cost of $1.0006 per Dth. The unit cost of $1.0006 per Dth represents the direct costs incurred by the Marketer, which are paid directly to the pipeline by the Marketer. Because this cost is $0.1863 per Dth greater than the system average, Marketers electing this path would be credited $0.1863 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 13 of Attachment EDA/SAJ-1.

Q. Does this conclude your testimony?

A. Yes.

Joint Attachments of
Arangio & Jaffe

Attachments of Elizabeth D. Arangio and Samara A. Jaffe

Attachment EDA/SAJ-1	Projected Gas Costs and Assignment of Pipeline Capacity – **CONFIDENTIAL Information**
Attachment EDA/SAJ-2	NYMEX Strip Comparison
Attachment EDA/SAJ-3	FT-2 Operational Parameters
Attachment EDA/SAJ-4	FT-2 Storage Variable Costs
Attachment EDA/SAJ-5	RFPs for PXP Phases I & II
Attachment EDA/SAJ-6	RFP for AMA Dracut to Citygate
Attachment EDA/SAJ-7	RFP for Citygate Deliveries
Attachment EDA/SAJ-8	Incremental Portable LNG Storage and Vaporization **CONFIDENTIAL Information**
Attachment EDA/SAJ-9	RFP for AMA Dawn to Tennessee Zone 6
Attachment EDA/SAJ-10	RFP for AMA TCo Broadrun to Hanover
Attachment EDA/SAJ-11	Tennessee FT-A Dracut to Cranston

Attachment EDA/SAJ-1
REDACTED

Attachment EDA/SAJ-1

Summary of Projected Gas Costs

REDACTED VERSION

National Grid Rhode Island
Gas Cost Recovery

Cost of Gas ($000)	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Total**
Normal Weather Scenario - Sales Only													
FIXED COSTS													
Total Transportation Fixed Costs	$ 5,330.7	$ 5,501.1	$ 5,499.8	$ 5,499.8	$ 5,499.8	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 64,636.4
Total Storage Delivery Fixed Costs	$ 403.4	$ 403.4	$ 403.4	$ 403.4	$ 403.4	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 4,663.1
Total Storage Fixed Costs	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 395.5	$ 4,746.6
Total Liquefaction Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Supplier Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LESS:													
AMA Credits	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 156.8	$ 1,881.9
Marketer Capacity Release Credits	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 961.2	$ 11,534.5
TOTAL FIXED COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 75,510.3
VARIABLE COSTS													
Commodity													
Commodity for Purchases to City Gate	$ 5,481.7	$ 8,006.7	$ 10,076.7	$ 9,190.0	$ 7,633.6	$ 4,350.3	$ 2,223.7	$ 1,412.7	$ 1,226.0	$ 1,268.0	$ 1,427.7	$ 3,050.1	$ 55,347.1
Commodity for Purchases to Injections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal													
Underground Storage Withdrawal Value	$ 72.5	$ 1,642.6	$ 2,069.5	$ 1,893.6	$ 1,321.5	$ 114.4	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,114.2
LNG Storage Withdrawal Value	$ 74.4	$ 83.7	$ 1,022.2	$ 587.5	$ 76.8	$ 68.6	$ 68.9	$ 66.5	$ 68.3	$ 68.3	$ 65.6	$ 67.3	$ 2,318.2
Total Storage Withdrawal Value	$ 146.8	$ 1,726.3	$ 3,091.7	$ 2,481.1	$ 1,398.4	$ 183.0	$ 68.9	$ 66.5	$ 68.3	$ 68.3	$ 65.6	$ 67.3	$ 9,432.3
Transportation													
Variable Costs for Purchases to City Gate	$ 269.5	$ 342.8	$ 376.2	$ 354.6	$ 316.8	$ 213.9	$ 125.2	$ 82.6	$ 72.4	$ 81.2	$ 77.9	$ 118.0	$ 2,431.2
Variable Costs for Storage Withdrawal	$ 5.1	$ 99.4	$ 125.7	$ 114.0	$ 77.8	$ 7.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 429.8
Variable Costs for Storage Injection	$ -	$ -	$ -	$ -	$ -	$ 135.5	$ 157.1	$ 151.8	$ 21.9	$ 17.4	$ 172.0	$ 44.4	$ 700.0
Total Transportation Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage Variable Costs	$ 0.7	$ 25.3	$ 35.2	$ 31.6	$ 15.9	$ 3.6	$ 14.6	$ 14.0	$ 9.8	$ 12.1	$ 18.5	$ 18.3	$ 199.7
LESS:													
LNG Trucking	$ -	$ -	$ -	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 165.1	$ 1,246.9	$ 1,198.8	$ 609.3	$ 920.1	$ 1,418.6	$ 1,421.9	$ 6,980.8
Liquefaction	$ -	$ -	$ -	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Storage and Liquefaction	$ -	$ -	$ -	$ -	$ -	$ 621.2	$ 1,716.2	$ 1,659.3	$ 637.8	$ 920.1	$ 1,918.0	$ 1,487.1	$ 8,959.9
TOTAL VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 67,640.4
TOTAL FIXED AND VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 143,150.7
NGPMP Credit	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 5,700.0
TOTAL GAS COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 137,450.7

REDACTED VERSION

National Grid Rhode Island
Gas Commodity Costs
Normal Year
($000)

Commodity Costs													
	Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 32.0	$ 18.2	$ -	$ -	$ -	$ 9.2	$ -	$ -	$ -	$ -	$ -	$ 29.4	$ 88.8
Const Summer Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Const Winter Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dawn via IGTS	$ -	$ 10.7	$ 28.5	$ 8.4	$ 0.7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48.4
Dawn via PNGTS	$ 104.5	$ 772.2	$ 1,511.8	$ 1,457.1	$ 672.2	$ 19.4	$ -	$ 197.9	$ 162.0	$ -	$ -	$ -	$ 4,897.0
Dominion SP	$ 30.2	$ 35.5	$ 39.2	$ 36.3	$ 37.6	$ 7.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 186.6
Dracut Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Swing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millennium	$ 516.9	$ 574.9	$ 648.6	$ 601.2	$ 621.9	$ 558.3	$ 388.6	$ 117.0	$ -	$ 7.4	$ 2.1	$ 532.5	$ 4,569.5
Niagara	$ 63.0	$ 77.9	$ 81.7	$ 76.2	$ 79.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 378.1
TCO Appalachia	$ 1,557.7	$ 2,631.1	$ 2,787.4	$ 2,585.5	$ 2,657.6	$ 1,132.9	$ 106.4	$ 100.7	$ -	$ 106.7	$ 65.7	$ 57.5	$ 13,789.2
TCO M3	$ 61.1	$ 67.7	$ -	$ -	$ 96.0	$ 28.8	$ 5.3	$ -	$ -	$ -	$ -	$ 79.7	$ 338.6
Tetco M2	$ 1,549.6	$ 1,930.5	$ 2,064.8	$ 1,938.4	$ 1,844.8	$ 1,665.0	$ 1,629.5	$ 1,574.7	$ 1,568.9	$ 1,586.5	$ 1,493.3	$ 837.8	$ 19,683.8
Tetco M3	$ 523.8	$ 25.0	$ -	$ -	$ 146.9	$ 244.1	$ 340.1	$ -	$ -	$ -	$ 507.1	$ 1,828.6	$ 3,615.6
TGP Z4	$ 972.5	$ 1,561.6	$ 2,138.6	$ 1,935.9	$ 1,332.7	$ 707.5	$ 921.9	$ 558.7	$ 53.0	$ 431.3	$ 728.9	$ 1,017.3	$ 12,359.7
Transco Leidy	$ 70.4	$ 82.9	$ 89.6	$ 82.9	$ 83.9	$ 72.0	$ 58.0	$ 42.8	$ 37.6	$ 38.8	$ 42.4	$ 63.1	$ 764.4
Waddington	$ -	$ -	$ -	$ -	$ -	$ 66.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 66.9
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid Rhode Island
Gas Commodity Costs
Normal Year
($000)

Unit Cost	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Weighted Average**
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 2.16	$ 3.01	$ -	$ -	$ -	$ 2.20	$ -	$ -	$ -	$ -	$ -	$ 1.97	$ 2.22
Const Summer Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Const Winter Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dawn via IGTS	$ -	$ 2.62	$ 2.73	$ 2.73	$ 2.67	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.70
Dawn via PNGTS	$ 2.25	$ 2.62	$ 2.73	$ 2.73	$ 2.67	$ 2.32	$ -	$ 2.11	$ 2.17	$ -	$ -	$ -	$ 2.64
Dominion SP	$ 1.90	$ 2.16	$ 2.31	$ 2.29	$ 2.21	$ 2.05	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.17
Dracut Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Swing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millennium	$ 1.90	$ 2.16	$ 2.31	$ 2.29	$ 2.21	$ 2.05	$ 1.95	$ 1.97	$ -	$ 2.01	$ 1.87	$ 1.89	$ 2.10
Niagara	$ 1.95	$ 2.33	$ 2.45	$ 2.44	$ 2.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.31
TCO Appalachia	$ 2.03	$ 2.23	$ 2.36	$ 2.34	$ 2.25	$ 2.11	$ 2.07	$ 2.08	$ -	$ 2.08	$ 2.02	$ 2.05	$ 2.24
TCO M3	$ 2.16	$ 3.01	$ -	$ -	$ 2.72	$ 2.20	$ 2.04	$ -	$ -	$ -	$ -	$ 1.97	$ 2.38
Tetco M2	$ 1.89	$ 2.16	$ 2.33	$ 2.29	$ 2.23	$ 2.03	$ 1.92	$ 1.94	$ 1.98	$ 1.97	$ 1.82	$ 1.87	$ 2.05
Tetco M3	$ 2.16	$ 3.01	$ -	$ -	$ 2.72	$ 2.20	$ 2.04	$ -	$ -	$ -	$ 1.94	$ 1.97	$ 2.04
TGP Z4	$ 2.13	$ 2.36	$ 2.51	$ 2.48	$ 2.41	$ 2.18	$ 2.09	$ 2.11	$ 2.15	$ 2.14	$ 2.00	$ 2.03	$ 2.28
Transco Leidy	$ 1.88	$ 2.14	$ 2.31	$ 2.29	$ 2.17	$ 1.98	$ 1.88	$ 1.92	$ 1.94	$ 1.93	$ 1.81	$ 1.83	$ 2.03
Waddington	$ -	$ -	$ -	$ -	$ -	$ 2.21	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.21
Weighted Average	**$ 2.00**	**$ 2.29**	**$ 2.47**	**$ 2.44**	**$ 2.32**	**$ 2.12**	**$ 2.03**	**$ 2.05**	**$ 2.01**	**$ 2.01**	**$ 1.96**	**$ 1.96**	**$ 2.20**

REDACTED VERSION

REDACTED VERSION

National Grid Rhode Island
Gas Commodity Costs
Normal Year
($000)

Commodity to Injections													
	Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Const Summer Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Const Winter Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dawn via IGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn via PNGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion SP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dracut Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Long-Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Swing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millennium	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ 2.2	$ 106.4	$ 100.7	$ -	$ 106.7	$ 65.7	$ 36.9	$ 418.6
TCO M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M2	$ -	$ -	$ -	$ -	$ -	$ 135.2	$ 535.5	$ 519.7	$ 542.5	$ 532.6	$ 817.9	$ 837.8	$ 3,921.3
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4	$ -	$ -	$ -	$ -	$ -	$ 24.2	$ 584.2	$ 558.7	$ 53.0	$ 263.4	$ 528.2	$ 521.1	$ 2,532.8
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4963
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REDACTED VERSION

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

Transportation Costs	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
Dawn to E.Here	$ 0.9	$ 4.2	$ 7.7	$ 6.7	$ 2.3	$ 0.3	$ -	$ 3.3	$ 2.7	$ -	$ -	$ -	$ 28.2
Dawn to WADDY	$ -	$ 0.4	$ 0.9	$ 0.3	$ 0.0	$ 2.6	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.2
Dominion SP	$ 0.8	$ 0.9	$ 1.1	$ 1.0	$ 0.9	$ 0.2	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.0
Dracut	$ 0.7	$ 6.3	$ 12.0	$ 12.3	$ 6.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37.9
Everett	$ -	$ 2.7	$ 8.0	$ 5.5	$ 0.7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.8
LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Millennium/AIM	$ 27.7	$ 25.7	$ 26.6	$ 24.9	$ 26.6	$ 26.7	$ 19.2	$ 5.7	$ -	$ 0.4	$ 0.1	$ 28.6	$ 212.2
Niagara	$ 2.7	$ 2.8	$ 2.8	$ 2.7	$ 2.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.9
Storage Delivery	$ 50.5	$ 82.8	$ 89.9	$ 82.8	$ 81.0	$ 32.7	$ 14.8	$ 6.6	$ 10.4	$ 10.0	$ 8.0	$ 26.3	$ 495.7
TCO App	$ 13.4	$ 20.5	$ 20.6	$ 19.2	$ 20.6	$ 9.4	$ 0.9	$ 0.8	$ -	$ 0.9	$ 0.6	$ 0.5	$ 107.4
TCO App/M3/Storage	$ 44.5	$ 71.1	$ 70.9	$ 66.3	$ 71.4	$ 30.3	$ 0.1	$ -	$ -	$ -	$ -	$ 2.5	$ 357.1
TCO M3	$ 0.5	$ 0.4	$ -	$ -	$ 0.6	$ 0.2	$ 0.0	$ -	$ -	$ -	$ -	$ 0.7	$ 2.5
Tetco M2	$ 59.6	$ 78.4	$ 76.9	$ 77.0	$ 67.8	$ 55.7	$ 45.4	$ 43.5	$ 41.6	$ 42.7	$ 33.4	$ 6.4	$ 628.5
TetcoM2/M3	$ 36.6	$ 45.7	$ 52.5	$ 49.9	$ 34.6	$ 30.6	$ 31.0	$ 26.9	$ 21.4	$ 22.8	$ 31.9	$ 35.2	$ 419.1
Transco Leidy	$ 0.5	$ 0.6	$ 1.0	$ 0.9	$ 0.5	$ 0.5	$ 0.4	$ 0.3	$ 0.3	$ 0.3	$ 0.4	$ 0.5	$ 6.2
Zone 4	$ 27.4	$ 50.3	$ 61.5	$ 58.6	$ 39.0	$ 23.1	$ 9.4	$ -	$ -	$ 8.5	$ 10.5	$ 18.9	$ 307.4
Zone 4 CXN	$ 7.8	$ 24.1	$ 34.3	$ 28.9	$ 23.1	$ 9.4	$ 9.8	$ 1.2	$ 0.1	$ 0.8	$ 2.2	$ 6.4	$ 148.1
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Storage Costs													
	Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
Columbia FSS	$ -	$ 0.7	$ 0.9	$ 0.9	$ 0.5	$ 0.0	$ 0.8	$ 0.7	$ -	$ 0.8	$ 0.5	$ 0.3	$ 6.1
Dominion GSS	$ -	$ 4.0	$ 4.8	$ 3.8	$ 1.5	$ 1.1	$ 5.1	$ 4.7	$ 2.5	$ 3.5	$ 4.1	$ 4.0	$ 39.2
Dominion GSSTE	$ 0.7	$ 1.4	$ 1.4	$ 1.3	$ 1.4	$ 1.1	$ -	$ -	$ -	$ -	$ 5.4	$ 5.2	$ 18.2
Tennessee FSMA	$ -	$ 1.2	$ 1.2	$ 1.5	$ 2.3	$ -	$ 1.5	$ 1.4	$ -	$ 0.5	$ 1.4	$ 1.5	$ 12.4
Tetco FSS1	$ -	$ 0.2	$ 0.8	$ 0.8	$ 0.2	$ 0.1	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 3.9
Tetco SS1	$ -	$ 17.9	$ 26.1	$ 23.3	$ 9.8	$ 1.3	$ 7.0	$ 6.8	$ 7.0	$ 7.0	$ 6.8	$ 7.0	$ 119.8
Grand Total	**$ 0.7**	**$ 25.3**	**$ 35.2**	**$ 31.6**	**$ 15.9**	**$ 3.6**	**$ 14.6**	**$ 14.0**	**$ 9.8**	**$ 12.1**	**$ 18.5**	**$ 18.3**	**$ 199.7**

Withdrawal Value													
	Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
Columbia FSS	$ -	$ 94.8	$ 131.7	$ 122.4	$ 73.7	$ 2.3	$ -	$ -	$ -	$ -	$ -	$ -	$ 424.9
Dominion GSS	$ -	$ 534.6	$ 635.8	$ 492.8	$ 198.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,861.4
Dominion GSSTE	$ 72.5	$ 140.4	$ 140.4	$ 131.4	$ 140.4	$ 112.2	$ -	$ -	$ -	$ -	$ -	$ -	$ 737.3
Exeter LNG	$ 26.4	$ 34.1	$ 371.9	$ 300.1	$ 27.3	$ 22.6	$ 23.4	$ 22.7	$ 23.5	$ 23.5	$ 22.8	$ 23.6	$ 921.9
Providence LNG	$ 48.0	$ 49.6	$ 650.3	$ 287.4	$ 49.6	$ 46.0	$ 45.5	$ 43.8	$ 44.8	$ 44.8	$ 42.8	$ 43.7	$ 1,396.3
Tennessee FSMA	$ -	$ 295.0	$ 286.9	$ 359.0	$ 585.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,526.4
Tetco FSS1	$ -	$ 9.4	$ 43.6	$ 45.5	$ 10.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 109.3
Tetco SS1	$ -	$ 568.4	$ 831.1	$ 742.5	$ 312.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,454.9
Grand Total	**$ 146.8**	**$ 1,726.3**	**$ 3,091.7**	**$ 2,481.1**	**$ 1,398.4**	**$ 183.0**	**$ 68.9**	**$ 66.5**	**$ 68.3**	**$ 68.3**	**$ 65.6**	**$ 67.3**	**$ 9,432.3**

Injection Value													
	Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
Columbia FSS	$ -	$ -	$ -	$ -	$ -	$ 2.3	$ 108.1	$ 102.3	$ -	$ 108.4	$ 66.8	$ 37.5	$ 425.2
Dominion GSS	$ -	$ -	$ -	$ -	$ -	$ 79.6	$ 369.9	$ 346.4	$ 183.1	$ 261.0	$ 286.5	$ 283.8	$ 1,810.4
Dominion GSSTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 356.3	$ 352.9	$ 709.3
Exeter LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Providence LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee FSMA	$ -	$ -	$ -	$ -	$ -	$ -	$ 355.8	$ 347.1	$ -	$ 126.8	$ 329.9	$ 345.6	$ 1,505.1
Tetco FSS1	$ -	$ -	$ -	$ -	$ -	$ 3.7	$ 18.0	$ 17.6	$ 18.6	$ 18.5	$ 16.6	$ 17.6	$ 110.5
Tetco SS1	$ -	$ -	$ -	$ -	$ -	$ 79.5	$ 395.1	$ 385.5	$ 407.6	$ 405.4	$ 362.6	$ 384.5	$ 2,420.2
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4963
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National Grid Rhode Island
Transportation Fixed Costs
Normal Year
($000)

Transportation Costs	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Grand Total
Dawn to E.Here	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 1,159.1	$ 13,908.7
Dawn to WADDY	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 23.9	$ 286.4
Dominion SP	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 99.3
Dracut	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 92.9	$ 1,114.3
Everett	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 1,392.9
LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Manchester Lateral	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 262.8	$ 3,153.6
Millennium/AIM	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 924.2	$ 11,090.1
Niagara	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 89.7
Proposed CNG/LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Storage Delivery	$ 403.4	$ 403.4	$ 403.4	$ 403.4	$ 403.4	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 378.0	$ 4,663.1
TCO App	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 253.9	$ 3,047.4
TCO App/M3/Storage	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 355.2	$ 4,262.6
TCO M3	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 47.1	$ 565.2
Tetco M2	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 774.6	$ 9,294.9
TetcoM2/M3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 368.3	$ 4,420.1
Transco Leidy	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 116.2
Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Zone 4	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 616.3	$ 7,395.7
Zone 4 CXN	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 263.9	$ 3,167.3
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED VERSION

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

Storage Costs	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
Columbia FSS	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 9.7	$ 116.3
Dominion GSS	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 35.2	$ 422.9
Dominion GSSTE	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 43.8	$ 525.7
Providence LNG	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 1,964.9
Tennessee FSMA	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 47.3	$ 567.3
Tetco FSS1	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 17.5
Tetco SS1	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 94.3	$ 1,131.9
Grand Total	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 395.5**	**$ 4,746.6**

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

Supply Costs													
	Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Grand Total**
Everett Supply Deal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposed Everett Supply Deal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposed Summer Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposed Winter Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Algonquin Citygate Peaking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED VERSION

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

Storage Inventory

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20
LNG Storage	Beg Inv Value	$ 2,756.1	$ 2,681.7	$ 2,598.0	$ 1,575.8	$ 988.3	$ 911.5	$ 1,299.0	$ 1,699.5	$ 2,093.4	$ 2,053.6	$ 1,985.3	$ 2,419.0
LNG Storage	Beg Inv Volume	594	578	560	338	210	193	297	404	508	499	482	594
LNG Storage	End Inv Value	$ 2,681.7	$ 2,598.0	$ 1,575.8	$ 988.3	$ 911.5	$ 1,299.0	$ 1,699.5	$ 2,093.4	$ 2,053.6	$ 1,985.3	$ 2,419.0	$ 2,417.0
LNG Storage	End Inv Volume	578	560	338	210	193	297	404	508	499	482	594	594
Underground Storage	Beg Inv Value	$ 8,852.7	$ 8,780.2	$ 7,137.6	$ 5,068.1	$ 3,174.5	$ 1,853.0	$ 1,903.6	$ 3,150.5	$ 4,349.4	$ 4,958.7	$ 5,878.8	$ 7,297.4
Underground Storage	Beg Inv Volume	4,238	4,202	3,423	2,436	1,531	906	926	1,522	2,091	2,382	2,816	3,533
Underground Storage	End Inv Value	$ 8,780.2	$ 7,137.6	$ 5,068.1	$ 3,174.5	$ 1,853.0	$ 1,903.6	$ 3,150.5	$ 4,349.4	$ 4,958.7	$ 5,878.8	$ 7,297.4	$ 8,719.3
Underground Storage	End Inv Volume	4,202	3,423	2,436	1,531	906	926	1,522	2,091	2,382	2,816	3,533	4,238

The Narragansett Electric Company Gas Cost Recovery Receipt Point Volumes (MDth)	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AIM at Ramapo	15	6	-	-	-	4	-	-	-	-	-	15	40
Dawn via IGTS	-	4	10	3	0	-	-	-	-	-	-	-	18
Dawn via PNGTS	46	294	554	533	252	8	-	94	74	-	-	-	1,857
Dominion SP	16	16	17	16	17	4	-	-	-	-	-	-	86
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
Millennium	272	266	281	263	281	272	199	59	-	4	1	281	2,179
Niagara	32	33	33	31	33	-	-	-	-	-	-	-	164
TCO Appalachia	769	1,178	1,180	1,104	1,180	535	-	-	-	-	-	10	5,957
TCO M3	28	22	-	-	35	13	3	-	-	-	-	40	142
Tetco M2	819	895	887	847	827	752	569	544	517	534	371	-	7,562
Tetco M3	242	8	-	-	54	111	167	-	-	-	261	926	1,769
TGP Z4	457	662	852	779	553	313	162	-	-	78	100	245	4,202
Transco Leidy	37	39	39	36	39	36	31	22	19	20	23	34	377
Waddington	-	-	-	-	-	30	-	-	-	-	-	-	30
TOTAL PURCHASES TO CITY GATE	2,734	3,500	4,083	3,770	3,293	2,079	1,130	720	611	636	757	1,552	24,865
STORAGE WITHDRAWALS													
Columbia FSS	-	44	62	57	35	1	-	-	-	-	-	-	199
Dominion GSS	-	244	293	229	93	-	-	-	-	-	-	-	859
Dominion GSSTE	36	69	69	65	69	55	-	-	-	-	-	-	363
Exeter LNG	6	8	84	68	6	6	6	6	6	6	6	6	215
Providence LNG	10	10	138	61	10	10	10	10	10	10	10	10	302
Tennessee FSMA	-	138	134	167	270	-	-	-	-	-	-	-	709
Tetco SS1	-	279	407	364	153	-	-	-	-	-	-	-	1,203
Tetco FSS1	-	5	22	23	5	-	-	-	-	-	-	-	55
TOTAL WITHDRAWALS TO CITY GATE	52	797	1,209	1,034	642	72	17	16	17	17	16	17	3,905
GRAND TOTAL TO CITY GATE	2,786	4,297	5,292	4,804	3,934	2,152	1,146	736	628	653	773	1,568	28,770

	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Millennium	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	-	-	-	-	-	1	51	48	-	51	32	18	203
TCO M3	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2	-	-	-	-	-	66	279	268	273	270	449	448	2,054
Tetco M3	-	-	-	-	-	-	-	-	-	-	-	-	-
TGP Z4	-	-	-	-	-	11	280	265	25	123	264	257	1,224
Transco Leidy	-	-	-	-	-	-	-	-	-	-	-	-	-
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO INJECTIONS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
STORAGE WITHDRAWALS													
Columbia FSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSSTE	-	-	-	-	-	-	-	-	-	-	-	-	-
Exeter LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Providence LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee FSMA	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco SS1	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco FSS1	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WITHDRAWALS TO STORAGE INJECTION	-	-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL TO CITY GATE	-	-	-	-	-	199	734	702	305	444	866	740	3,989

REDACTED VERSION

The Narragansett Electric Company Gas Cost Recovery Delivery Point Volumes (MDth)	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AIM at Ramapo	14	6	-	-	-	4	-	-	-	-	-	15	39
Dawn via IGTS	-	4	10	3	0	-	-	-	-	-	-	-	17
Dawn via PNGTS	46	289	544	523	247	8	-	92	73	-	-	-	1,823
Dominion SP	15	16	16	15	16	4	-	-	-	-	-	-	83
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
Millennium	265	253	267	250	267	265	194	58	-	4	1	274	2,097
Niagara	32	33	33	31	33	-	-	-	-	-	-	-	162
TCO Appalachia	754	1,153	1,155	1,081	1,155	525	-	-	-	-	-	10	5,832
TCO M3	28	22	-	-	35	13	3	-	-	-	-	40	139
Tetco M2	801	869	862	822	803	736	557	533	506	523	363	-	7,373
Tetco M3	241	8	-	-	54	111	166	-	-	-	260	922	1,760
TGP Z4	451	653	841	769	546	309	159	-	-	77	99	241	4,145
Transco Leidy	37	38	38	36	38	36	31	22	19	20	23	34	372
Waddington	-	-	-	-	-	30	-	-	-	-	-	-	30
TOTAL PURCHASES TO CITY GATE	2,683	3,420	3,994	3,687	3,215	2,039	1,109	704	598	623	746	1,535	24,354
STORAGE WITHDRAWALS													
Columbia FSS	-	43	60	56	34	1	-	-	-	-	-	-	195
Dominion GSS	-	237	285	222	90	-	-	-	-	-	-	-	833
Dominion GSSTE	35	67	67	63	67	54	-	-	-	-	-	-	354
Exeter LNG	6	8	84	68	6	6	6	6	6	6	6	6	215
Providence LNG	10	10	138	61	10	10	10	10	10	10	10	10	302
Tennessee FSMA	-	136	132	165	266	-	-	-	-	-	-	-	700
Tetco SS1	-	272	397	355	150	-	-	-	-	-	-	-	1,174
Tetco FSS1	-	5	21	22	5	-	-	-	-	-	-	-	53
TOTAL WITHDRAWALS TO CITY GATE	51	778	1,185	1,012	629	71	17	16	17	17	16	17	3,825
GRAND TOTAL TO CITY GATE	2,734	4,198	5,179	4,699	3,844	2,110	1,125	720	615	640	762	1,551	28,179
	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Millennium	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	-	-	-	-	-	1	50	47	-	50	32	18	199
TCO M3	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2	-	-	-	-	-	65	272	262	267	264	437	436	2,002
Tetco M3	-	-	-	-	-	-	-	-	-	-	-	-	-
TGP Z4	-	-	-	-	-	11	273	259	24	120	257	251	1,196
Transco Leidy	-	-	-	-	-	-	-	-	-	-	-	-	-
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO INJECTIONS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
STORAGE WITHDRAWALS													
Columbia FSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSSTE	-	-	-	-	-	-	-	-	-	-	-	-	-
Exeter LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Providence LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee FSMA	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco SS1	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco FSS1	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WITHDRAWALS TO STORAGE INJECTION	-	-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL TO CITY GATE	-	-	-	-	-	197	720	689	298	434	846	721	3,905

REDACTED VERSION

PRELIMINARY

12 Month Forward Pricing

National Grid
Summary of Transportation Capacity Release
Pipeline Path Availability and Pricing
November 2019 - October 2020

Path to City Gate	As of 8/1/19 Existing Releases	Total Available	Remaining Available	Cost per Dth	New Credit or Surcharge	Old Credit or Surcharge
Company Weighted Average				**$0.8143**		
Tennessee - Zone 1	9,500	9,500	0	$1.0006	($0.1863)	($0.2605)
Tennessee - Dracut	578	1,000	422	$1.9442	($1.1299)	($1.4999)
Algonquin at Lambertville, NJ	2,608	2,714	106	$0.5848	$0.2295	$0.2501
Texas Eastern - South Texas	4,043	4,044	1	$1.4064	($0.5921)	($0.3887)
Texas Eastern - West Louisiana	8,500	8,500	0	$1.1466	($0.3323)	($0.1081)
Texas Eastern - East Louisiana	6,500	6,500	0	$0.9623	($0.1480)	($0.0154)
Columbia - Maumee & Pennsburg*	3,000	3,000	0	$0.3349	$0.4794	$0.4991
Totals:	34,729	35,258	529			

* Note: Marketers selecting this path are assigned 5/6 of the amount selected at the Maumee, OH receipt point into Columbia and 1/6 at the Pennsburg, PA Receipt into Columbia.

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4963
Attachment EDA/SAJ-1
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REDACTED VERSION

National Grid Rhode Island Company Average Costs Per Unit Costs ($000) and Volumes (MDth)	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Total**
Commodity and Variable Costs													
Commodity for Purchases to City Gate	$ 5,481.7	$ 8,006.7	$ 10,076.7	$ 9,190.0	$ 7,633.6	$ 4,350.3	$ 2,223.7	$ 1,412.7	$ 1,226.0	$ 1,268.0	$ 1,427.7	$ 3,050.1	$ 55,347.1
Variable Costs for Purchases to City Gate	$ 269.5	$ 342.8	$ 376.2	$ 354.6	$ 316.8	$ 213.9	$ 125.2	$ 82.6	$ 72.4	$ 81.2	$ 77.9	$ 118.0	$ 2,431.2
Total Cost for Purchases to City Gate	$ 5,751.2	$ 8,349.5	$ 10,452.9	$ 9,544.6	$ 7,950.4	$ 4,564.2	$ 2,348.8	$ 1,495.4	$ 1,298.3	$ 1,349.2	$ 1,505.6	$ 3,168.1	$ 57,778.3
08/01/2019 NYMEX	$ 2.293	$ 2.488	$ 2.617	$ 2.589	$ 2.514	$ 2.349	$ 2.335	$ 2.380	$ 2.427	$ 2.438	$ 2.422	$ 2.449	
Pipeline Purchases to City Gate	2,683	3,420	3,994	3,687	3,215	2,039	1,109	704	598	623	746	1,535	24,354
NYMEX Cost of Pipeline Purchases	$ 6,153.0	$ 8,508.5	$ 10,452.7	$ 9,546.1	$ 8,083.3	$ 4,789.8	$ 2,588.5	$ 1,676.2	$ 1,452.1	$ 1,519.5	$ 1,806.1	$ 3,758.4	$ 60,334.4
Non-Gas Cost of Delivered Supplies													**$ (0.1050)**
Fixed Costs													
Transportation Fixed Costs	$ 5,330.7	$ 5,501.1	$ 5,499.8	$ 5,499.8	$ 5,499.8	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 5,329.3	$ 64,636.4
Less Everett for Peaking	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 116.1	$ 1,392.9
Less Dracut for Peaking	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 103.5	$ 1,242.2
Total Pipeline Fixed Costs	$ 5,111.1	$ 5,281.5	$ 5,280.2	$ 5,280.2	$ 5,280.2	$ 5,109.7	$ 5,109.7	$ 5,109.7	$ 5,109.7	$ 5,109.7	$ 5,109.7	$ 5,109.7	$ 62,001.2
Total Fixed Units	5,687	5,903	5,903	5,523	5,903	5,687	5,850	5,205	5,379	5,379	5,205	5,850	67,474
100% Load Factor Unit Value ($/Dth)													**$ 0.9189**
Marketer Reconciliation 2018/19													$ 4.6
Marketer Fixed Units	1,042	1,077	1,077	1,007	1,077	1,042	1,077	1,042	1,077	1,077	1,042	1,077	12,711
100% Load Factor Unit Value ($/Dth)													**$ 0.0004**
Total Average System Unit Value ($/Dth)													**$ 0.8143**

REDACTED VERSION

TEXAS EASTERN SOUTH TEXAS SUPPLY PATH COST MATRIX
CITY GATE DELIVERED MDQ = 4,044

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
				UNIT PRICING										
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	$8.5490	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	
TETCO M1 TO M3 DEMAND	$/Dth	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	
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	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	$0.0905	
ALGONQUIN USAGE	$/Dth	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY AREA BASIS	$/Dth	($0.1070)	($0.1050)	($0.1130)	($0.0850)	($0.0850)	($0.1150)	($0.1170)	($0.1200)	($0.1270)	($0.1280)	($0.1200)	($0.1230)	
NET COST AFTER BASIS	$/Dth	$2.1860	$2.3830	$2.5040	$2.5040	$2.4290	$2.2340	$2.2180	$2.2600	$2.3000	$2.3100	$2.3020	$2.3260	
				BILLING UNITS										
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	4,065	4,070	4,070	4,070	4,070	4,065	4,065	4,065	4,065	4,065	4,065	4,065	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	4,065	4,070	4,070	4,070	4,070	4,065	4,065	4,065	4,065	4,065	4,065	4,065	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	4,065	4,070	4,070	4,070	4,070	4,065	4,065	4,065	4,065	4,065	4,065	4,065	
TETCO M1 TO M3 DEMAND	$/Dth	4,065	4,070	4,070	4,070	4,070	4,065	4,065	4,065	4,065	4,065	4,065	4,065	
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	125,908	131,470	131,470	122,988	131,470	125,908	130,105	125,908	130,105	130,105	125,908	130,105	1,541,449
TETCO USAGE STX TO M3	Dth	121,942	126,171	126,171	118,031	126,171	121,942	126,007	121,942	126,007	126,007	121,942	126,007	1,488,340
ALGONQUIN USAGE	Dth	121,320	125,364	125,364	117,276	125,364	121,320	125,364	121,320	125,364	125,364	121,320	125,364	1,480,104
DELIVERED VOLUMES	Dth	121,320	125,364	125,364	117,276	125,364	121,320	125,364	121,320	125,364	125,364	121,320	125,364	1,480,104
				FUEL USE %										
TETCO STX TO M3 FUEL	%	3.150%	4.030%	4.030%	4.030%	4.030%	3.150%	3.150%	3.150%	3.150%	3.150%	3.150%	3.150%	
ALGONQUIN AFT-E FUEL	%	0.510%	0.640%	0.640%	0.640%	0.640%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	
				TRANSPORTATION COST										
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$	$34,749	$34,795	$34,795	$34,795	$34,795	$34,749	$34,749	$34,749	$34,749	$34,749	$34,749	$34,749	$417,174
TECCO WLA SUPPLY ZONE DEMAND	$	$18,726	$18,751	$18,751	$18,751	$18,751	$18,726	$18,726	$18,726	$18,726	$18,726	$18,726	$18,726	$224,813
TETCO ELA SUPPLY ZONE DEMAND	$	$12,938	$12,955	$12,955	$12,955	$12,955	$12,938	$12,938	$12,938	$12,938	$12,938	$12,938	$12,938	$155,324
TETCO M1 TO M3 DEMAND	$	$63,048	$63,131	$63,131	$63,131	$63,131	$63,048	$63,048	$63,048	$63,048	$63,048	$63,048	$63,048	$756,906
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	$	$11,036	$11,419	$11,419	$10,682	$11,419	$11,036	$11,404	$11,036	$11,404	$11,404	$11,036	$11,404	$134,695
ALGONQUIN USAGE	$	$7,461	$7,710	$7,710	$7,212	$7,710	$7,461	$7,710	$7,461	$7,710	$7,710	$7,461	$7,710	$91,026
PURCHASE COST	$	$275,235	$313,292	$329,200	$307,961	$319,340	$281,278	$288,573	$284,552	$299,241	$300,542	$289,840	$302,624	$3,591,680
TOTAL FIXED	$	$156,044	$156,214	$156,214	$156,214	$156,214	$156,044	$156,044	$156,044	$156,044	$156,044	$156,044	$156,044	$1,873,211
TOTAL VARIABLE	$	$293,732	$332,421	$348,329	$325,856	$338,468	$299,775	$307,686	$303,049	$318,355	$319,656	$308,337	$321,738	$3,817,401
DELIVERED COST AT NYMEX	$	$278,187	$311,906	$328,078	$303,628	$315,165	$284,981	$292,725	$288,742	$304,258	$305,637	$293,837	$307,016	$3,614,159
NET NON-GAS VARIABLE COST	$	$15,545	$20,515	$20,251	$22,228	$23,303	$14,795	$14,961	$14,307	$14,096	$14,018	$14,500	$14,721	$203,242
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1281**	**$0.1636**	**$0.1615**	**$0.1895**	**$0.1859**	**$0.1219**	**$0.1193**	**$0.1179**	**$0.1124**	**$0.1118**	**$0.1195**	**$0.1174**	**$0.1373**
AVERAGE FIXED COST	$/Dth													$38.6006
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$1.2691**
TOTAL PATH COST	$/Dth													**$1.4064**

TEXAS EASTERN WEST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE
CITY GATE DELIVERED MDQ = 8,500

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
UNIT PRICING														
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$/Dth	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	$4.6070	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	
TETCO M1 TO M3 DEMAND	$/Dth	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	
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	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	$0.0870	
ALGONQUIN USAGE	$/Dth	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY AREA BASIS	$/Dth	($0.0870)	($0.0820)	($0.1070)	($0.0800)	($0.0700)	($0.0770)	($0.0750)	($0.0820)	($0.0850)	($0.0850)	($0.0820)	($0.0800)	
NET COST AFTER BASIS	$/Dth	$2.2060	$2.4060	$2.5100	$2.5090	$2.4440	$2.2720	$2.2600	$2.2980	$2.3420	$2.3530	$2.3400	$2.3690	
BILLING UNITS														
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	Dth	8,544	8,555	8,555	8,555	8,555	8,544	8,544	8,544	8,544	8,544	8,544	8,544	
TETCO ELA SUPPLY ZONE DEMAND	Dth	8,544	8,555	8,555	8,555	8,555	8,544	8,544	8,544	8,544	8,544	8,544	8,544	
TETCO M1 TO M3 DEMAND	Dth	8,544	8,555	8,555	8,555	8,555	8,544	8,544	8,544	8,544	8,544	8,544	8,544	
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	264,289	275,644	275,644	257,861	275,644	264,289	273,098	264,289	273,098	273,098	264,289	273,098	3,234,341
TETCO USAGE WLA TO M3	Dth	256,307	265,197	265,197	248,088	265,197	256,307	264,851	256,307	264,851	264,851	256,307	264,851	3,128,311
ALGONQUIN USAGE	Dth	255,000	263,500	263,500	246,500	263,500	255,000	263,500	255,000	263,500	263,500	255,000	263,500	3,111,000
DELIVERED VOLUMES	Dth	255,000	263,500	263,500	246,500	263,500	255,000	263,500	255,000	263,500	263,500	255,000	263,500	3,111,000
FUEL USE %														
TETCO WLA TO M3 FUEL	%	3.020%	3.790%	3.790%	3.790%	3.790%	3.020%	3.020%	3.020%	3.020%	3.020%	3.020%	3.020%	
ALGONQUIN AFT-E FUEL	%	0.510%	0.640%	0.640%	0.640%	0.640%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	
TRANSPORTATION COST														
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$	$39,360	$39,412	$39,412	$39,412	$39,412	$39,360	$39,360	$39,360	$39,360	$39,360	$39,360	$39,360	$472,529
TETCO ELA SUPPLY ZONE DEMAND	$	$27,194	$27,230	$27,230	$27,230	$27,230	$27,194	$27,194	$27,194	$27,194	$27,194	$27,194	$27,194	$326,473
TETCO M1 TO M3 DEMAND	$	$132,519	$132,693	$132,693	$132,693	$132,693	$132,519	$132,519	$132,519	$132,519	$132,519	$132,519	$132,519	$1,590,926
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	$	$22,299	$23,072	$23,072	$21,584	$23,072	$22,299	$23,042	$22,299	$23,042	$23,042	$22,299	$23,042	$272,163
ALGONQUIN USAGE	$	$15,683	$16,205	$16,205	$15,160	$16,205	$15,683	$16,205	$15,683	$16,205	$16,205	$15,683	$16,205	$191,327
PURCHASE COST	$	$583,021	$663,200	$691,867	$646,972	$673,674	$600,464	$617,202	$607,335	$639,596	$642,600	$618,436	$646,970	$7,631,338
TOTAL FIXED	$	$254,948	$255,208	$255,208	$255,208	$255,208	$254,948	$254,948	$254,948	$254,948	$254,948	$254,948	$254,948	$3,060,414
TOTAL VARIABLE	$	$621,002	$702,477	$731,144	$683,716	$712,952	$638,445	$656,449	$645,317	$678,844	$681,848	$656,417	$686,217	$8,094,827
DELIVERED VOLUMES AT NYMEX	$	$584,715	$655,588	$689,580	$638,189	$662,439	$598,995	$615,273	$606,900	$639,515	$642,413	$617,610	$645,312	$7,596,527
NET NON-GAS VARIABLE COST	$	$36,287	$46,889	$41,565	$45,527	$50,513	$39,450	$41,177	$38,417	$39,329	$39,435	$38,807	$40,906	$498,301
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1423**	**$0.1779**	**$0.1577**	**$0.1847**	**$0.1917**	**$0.1547**	**$0.1563**	**$0.1507**	**$0.1493**	**$0.1497**	**$0.1522**	**$0.1552**	**$0.1602**
AVERAGE FIXED COST	$/Dth													$30.0041
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.9864**
TOTAL PATH COST	$/Dth													**$1.1466**

TEXAS EASTERN EAST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE

CITY GATE DELIVERED MDQ = 6,500

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
						UNIT PRICING								
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	$3.1830	
TETCO M1 TO M3 DEMAND	$/Dth	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	$15.5110	
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	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	$0.0857	
ALGONQUIN USAGE	$/Dth	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY AREA BASIS	$/Dth	($0.1070)	($0.1050)	($0.1130)	($0.0850)	($0.0850)	($0.1150)	($0.1170)	($0.1200)	($0.1270)	($0.1280)	($0.1200)	($0.1230)	
NET COST AFTER BASIS	$/Dth	$2.1860	$2.3830	$2.5040	$2.5040	$2.4290	$2.2340	$2.2180	$2.2600	$2.3000	$2.3100	$2.3020	$2.3260	
						BILLING UNITS								
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	Dth	6,533	6,542	6,542	6,542	6,542	6,533	6,533	6,533	6,533	6,533	6,533	6,533	
TETCO M1 TO M3 DEMAND	Dth	6,533	6,542	6,542	6,542	6,542	6,533	6,533	6,533	6,533	6,533	6,533	6,533	
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	202,082	210,809	210,809	197,208	210,809	202,082	208,818	202,082	208,818	208,818	202,082	208,818	2,473,236
TETCO USAGE ELA TO M3	Dth	196,000	202,798	202,798	189,714	202,798	196,000	202,533	196,000	202,533	202,533	196,000	202,533	2,392,238
ALGONQUIN USAGE	Dth	195,000	201,500	201,500	188,500	201,500	195,000	201,500	195,000	201,500	201,500	195,000	201,500	2,379,000
DELIVERED VOLUMES	Dth	195,000	201,500	201,500	188,500	201,500	195,000	201,500	195,000	201,500	201,500	195,000	201,500	2,379,000
						FUEL USE %								
TETCO ELA TO M3 FUEL	%	3.010%	3.800%	3.800%	3.800%	3.800%	3.010%	3.010%	3.010%	3.010%	3.010%	3.010%	3.010%	
ALGONQUIN AFT-E FUEL	%	0.510%	0.640%	0.640%	0.640%	0.640%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	
						TRANSPORTATION COST								
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	$	$20,796	$20,823	$20,823	$20,823	$20,823	$20,796	$20,796	$20,796	$20,796	$20,796	$20,796	$20,796	$249,656
TETCO M1 TO M3 DEMAND	$	$101,338	$101,471	$101,471	$101,471	$101,471	$101,338	$101,338	$101,338	$101,338	$101,338	$101,338	$101,338	$1,216,590
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	$	$16,797	$17,380	$17,380	$16,259	$17,380	$16,797	$17,357	$16,797	$17,357	$17,357	$16,797	$17,357	$205,015
ALGONQUIN USAGE	$	$11,993	$12,392	$12,392	$11,593	$12,392	$11,993	$12,392	$11,993	$12,392	$12,392	$11,993	$12,392	$146,309
PURCHASE COST	$	$441,752	$502,357	$527,865	$493,809	$512,054	$451,452	$463,159	$456,706	$480,282	$482,370	$465,193	$485,711	$5,762,711
TOTAL FIXED	$	$164,861	$165,021	$165,021	$165,021	$165,021	$164,861	$164,861	$164,861	$164,861	$164,861	$164,861	$164,861	$1,978,971
TOTAL VARIABLE	$	$470,542	$532,129	$557,637	$521,660	$541,826	$480,241	$492,908	$485,496	$510,032	$512,120	$493,983	$515,461	$6,114,034
DELIVERED VOLUMES AT NYMEX	$	$447,135	$501,332	$527,326	$488,027	$506,571	$458,055	$470,503	$464,100	$489,041	$491,257	$472,290	$493,474	$5,809,109
NET NON-GAS VARIABLE COST	$	$23,407	$30,797	$30,311	$33,634	$35,255	$22,186	$22,406	$21,396	$20,991	$20,863	$21,693	$21,987	$304,926
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1200**	**$0.1528**	**$0.1504**	**$0.1784**	**$0.1750**	**$0.1138**	**$0.1112**	**$0.1097**	**$0.1042**	**$0.1035**	**$0.1112**	**$0.1091**	**$0.1282**
AVERAGE FIXED COST	$/Dth													$25.3714
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.8341**
TOTAL PATH COST	$/Dth													**$0.9623**

REDACTED VERSION

MAUMEE/PENNSBURG COLUMBIA PATH TO CITY GATE
CITY GATE DELIVERED MDQ = 3,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
UNIT PRICING														
FIXED														
COLUMBIA FTS DEMAND	$/Dth	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	$6.7720	
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	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	
ALGONQUIN USAGE	$/Dth	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY BASIS MAUMEE	$/Dth	($0.2670)	($0.2550)	($0.2550)	($0.2470)	($0.2620)	($0.2370)	($0.2630)	($0.2980)	($0.3300)	($0.3600)	($0.4000)	($0.3970)	
SUPPLY BASIS PENNSBURG	$/Dth	($0.1300)	$0.5250	$2.6670	$2.5600	$0.2080	($0.1530)	($0.2930)	($0.3120)	($0.2600)	($0.2880)	($0.4780)	($0.4750)	
NET COST AFTER BASIS MAUMEE	$/Dth	$2.0260	$2.2330	$2.3620	$2.3420	$2.2520	$2.1120	$2.0720	$2.0820	$2.0970	$2.0780	$2.0220	$2.0520	
NET COST AFTER BASIS PENNSBURG	$/Dth	$2.1630	$3.0130	$5.2840	$5.1490	$2.7220	$2.1960	$2.0420	$2.0680	$2.1670	$2.1500	$1.9440	$1.9740	
BILLING UNITS														
FIXED														
COLUMBIA FTS DEMAND	Dth	3,015	3,019	3,019	3,019	3,019	3,015	3,015	3,015	3,015	3,015	3,015	3,015	
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	76,526	77,999	77,999	72,967	77,999	75,384	77,897	75,384	77,897	77,897	75,384	77,897	
PURCHASE VOLUMES PENNSBURG	Dth	15,305	15,600	15,600	14,593	15,600	15,077	15,579	15,077	15,579	15,579	15,077	15,579	
COLUMBIA USAGE	Dth	90,461	93,599	93,599	87,560	93,599	90,461	93,477	90,461	93,477	93,477	90,461	93,477	
ALGONQUIN USAGE	Dth	90,000	93,000	93,000	87,000	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	72,500	77,500	75,000	77,500	75,000	77,500	77,500	75,000	77,500	915,000
DELIVERED VOLUMES PENNSBURG	Dth	15,000	15,500	15,500	14,500	15,500	15,000	15,500	15,000	15,500	15,500	15,000	15,500	183,000
FUEL USE %														
COLUMBIA FUEL	%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	1.492%	
ALGONQUIN AFT-E FUEL	%	0.510%	0.640%	0.640%	0.640%	0.640%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	
TRANSPORTATION COST														
FIXED														
COLUMBIA FTS DEMAND	$	$20,420	$20,447	$20,447	$20,447	$20,447	$20,420	$20,420	$20,420	$20,420	$20,420	$20,420	$20,420	$245,149
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	$	$1,601	$1,657	$1,657	$1,550	$1,657	$1,601	$1,655	$1,601	$1,655	$1,655	$1,601	$1,655	$19,543
ALGONQUIN USAGE	$	$5,535	$5,720	$5,720	$5,351	$5,720	$5,535	$5,720	$5,535	$5,720	$5,720	$5,535	$5,720	$67,527
PURCHASE COST MAUMEE	$	$155,042	$174,172	$184,234	$170,889	$175,654	$159,212	$161,403	$156,950	$163,351	$161,871	$152,427	$159,845	$1,975,051
PURCHASE COST PENNSBURG	$	$33,105	$47,002	$82,430	$75,141	$42,463	$33,109	$31,813	$31,179	$33,761	$33,496	$29,309	$30,754	$503,562
TOTAL FIXED	$	$40,140	$40,167	$40,167	$40,167	$40,167	$40,140	$40,140	$40,140	$40,140	$40,140	$40,140	$40,140	$481,791
TOTAL VARIABLE	$	$195,284	$228,551	$274,040	$252,930	$225,493	$199,457	$200,590	$195,266	$204,485	$202,740	$188,873	$197,973	$2,565,683
DELIVERED VOLUMES AT NYMEX	$	$206,370	$231,384	$243,381	$225,243	$233,802	$211,410	$217,155	$214,200	$225,711	$226,734	$217,980	$227,757	$2,681,127
NET NON-GAS VARIABLE COST	$	-$11,086	-$2,833	$30,659	$27,687	-$8,309	-$11,953	-$16,565	-$18,934	-$21,226	-$23,994	-$29,107	-$29,784	-$115,444
AVERAGE NON-GAS VARIABLE COST	$/Dth	**-$0.1232**	**-$0.0305**	**$0.3297**	**$0.3182**	**-$0.0893**	**-$0.1328**	**-$0.1781**	**-$0.2104**	**-$0.2282**	**-$0.2580**	**-$0.3234**	**-$0.3203**	**-$0.1051**
AVERAGE FIXED COST	$/Dth													$13.3831
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.4400**
TOTAL PATH COST	$/Dth													**$0.3349**

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TENNESSEE ZONE 1 TO CITY GATE

CITY GATE DELIVERED MDQ = 9,500

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
UNIT PRICING														
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$/Dth	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	$21.0092	
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$/Dth	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	$0.2959	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY AREA BASIS	$/Dth	($0.1290)	($0.0740)	($0.1160)	($0.0450)	($0.0720)	($0.1010)	($0.1230)	($0.1220)	($0.1050)	($0.0840)	($0.0920)	($0.0970)	
NET COST AFTER BASIS	$/Dth	$2.1640	$2.4140	$2.5010	$2.5440	$2.4420	$2.2480	$2.2120	$2.2580	$2.3220	$2.3540	$2.3300	$2.3520	
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	298,461	308,409	308,409	288,512	308,409	298,461	308,409	298,461	308,409	308,409	298,461	308,409	3,641,219
TENNESSE ZONE 1 TO 6 USAGE	Dth	285,000	294,500	294,500	275,500	294,500	285,000	294,500	285,000	294,500	294,500	285,000	294,500	3,477,000
DELIVERED VOLUMES	Dth	285,000	294,500	294,500	275,500	294,500	285,000	294,500	285,000	294,500	294,500	285,000	294,500	3,477,000
FUEL USE %														
TENNESSEE ZONE 1 TO 6 FUEL	%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	4.510%	
TRANSPORTATION COST														
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$2,395,049
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$	$84,332	$87,143	$87,143	$81,520	$87,143	$84,332	$87,143	$84,332	$87,143	$87,143	$84,332	$87,143	$1,028,844
PURCHASE COST	$	$645,869	$744,500	$771,332	$733,974	$753,135	$670,939	$682,201	$673,924	$716,126	$725,995	$695,413	$725,379	$8,538,788
TOTAL FIXED	$	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$199,587	$2,395,049
TOTAL VARIABLE	$	$730,200	$831,642	$858,474	$815,495	$840,278	$755,271	$769,344	$758,255	$803,269	$813,138	$779,745	$812,521	$9,567,632
DELIVERED VOLUMES AT NYMEX	$	$653,505	$732,716	$770,707	$713,270	$740,373	$669,465	$687,658	$678,300	$714,752	$717,991	$690,270	$721,231	$8,490,236
NET NON-GAS VARIABLE COST	$	$76,695	$98,926	$87,768	$102,225	$99,905	$85,806	$81,686	$79,955	$88,517	$95,147	$89,475	$91,291	$1,077,397
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.2691**	**$0.3359**	**$0.2980**	**$0.3711**	**$0.3392**	**$0.3011**	**$0.2774**	**$0.2805**	**$0.3006**	**$0.3231**	**$0.3139**	**$0.3100**	**$0.3099**
AVERAGE FIXED COST	$/Dth													$21.0092
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.6907**
TOTAL PATH COST	$/Dth													**$1.0006**

REDACTED VERSION

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ALGONQUIN LAMBERTVILLE TO CITY GATE

CITY GATE DELIVERED MDQ = 2,714

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
						UNIT PRICING								
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	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	$0.0615	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY AREA BASIS	$/Dth	($0.1300)	$0.5250	$2.6670	$2.5600	$0.2080	($0.1530)	($0.2930)	($0.3120)	($0.2600)	($0.2880)	($0.4780)	($0.4750)	
NET COST AFTER BASIS	$/Dth	$2.1630	$3.0130	$5.2840	$5.1490	$2.7220	$2.1960	$2.0420	$2.0680	$2.1670	$2.1500	$1.9440	$1.9740	
						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	81,837	84,676	84,676	79,213	84,676	81,837	84,565	81,837	84,565	84,565	81,837	84,565	998,851
ALGONQUIN AFT-E USAGE	Dth	81,420	84,134	84,134	78,706	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	993,324
DELIVERED VOLUMES	Dth	81,420	84,134	84,134	78,706	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	993,324
						FUEL USE %								
ALGONQUIN AFT-E FUEL	%	0.510%	0.640%	0.640%	0.640%	0.640%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	0.510%	
						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	$	$5,007	$5,174	$5,174	$4,840	$5,174	$5,007	$5,174	$5,007	$5,174	$5,174	$5,007	$5,174	$61,089
PURCHASE COST	$	$177,014	$255,129	$447,428	$407,868	$230,488	$179,715	$172,682	$169,240	$183,253	$181,815	$159,092	$166,932	$2,730,655
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	$	$182,022	$260,303	$452,602	$412,708	$235,662	$184,722	$177,857	$174,247	$188,427	$186,990	$164,099	$172,106	$2,791,744
DELIVERED VOLUMES AT NYMEX	$	$186,696	$209,325	$220,179	$203,770	$211,513	$191,256	$196,453	$193,780	$204,193	$205,119	$197,199	$206,044	$2,425,526
NET NON-GAS VARIABLE COST	$	-$4,674	$50,977	$232,423	$208,938	$24,149	-$6,533	-$18,596	-$19,533	-$15,766	-$18,129	-$33,100	-$33,938	$366,218
AVERAGE NON-GAS VARIABLE COST	$/Dth	**-$0.0574**	**$0.6059**	**$2.7625**	**$2.6547**	**$0.2870**	**-$0.0802**	**-$0.2210**	**-$0.2399**	**-$0.1874**	**-$0.2155**	**-$0.4065**	**-$0.4034**	**$0.3687**
AVERAGE FIXED COST	$/Dth													$6.5734
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.2161**
TOTAL PATH COST	$/Dth													**$0.5848**

REDACTED VERSION

TENNESSEE DRACUT TO CITY GATE

CITY GATE DELIVERED MDQ = 1,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
						UNIT PRICING								
FIXED														
TENNESSEE ZONE 6 TO 6 DEMAND	$/Dth	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	$4.6431	
VARIABLE														
TENNESSE ZONE 6 TO 6 USAGE	$/Dth	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	$0.0350	
08/01/2019 NYMEX	$/Dth	$2.2930	$2.4880	$2.6170	$2.5890	$2.5140	$2.3490	$2.3350	$2.3800	$2.4270	$2.4380	$2.4220	$2.4490	
SUPPLY AREA BASIS	$/Dth	$1.3170	$3.7600	$5.7770	$5.6700	$2.8160	$0.8450	$0.0900	$0.1450	$0.3370	$0.3300	($0.0080)	$0.1000	
NET COST AFTER BASIS	$/Dth	$3.6100	$6.2480	$8.3940	$8.2590	$5.3300	$3.1940	$2.4250	$2.5250	$2.7640	$2.7680	$2.4140	$2.5490	
						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	30,000	31,000	31,000	29,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	366,000
TENNESSE ZONE 6 TO 6 USAGE	Dth	30,000	31,000	31,000	29,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	366,000
DELIVERED VOLUMES	Dth	30,000	31,000	31,000	29,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	366,000
						FUEL USE %								
TENNESSEE ZONE 6 TO 6 FUEL	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
						TRANSPORTATION COST								
FIXED														
TENNESSEE ZONE 6 TO 6 DEMAND	$	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$55,717
VARIABLE														
TENNESSE ZONE 6 TO 6 USAGE	$	$1,050	$1,085	$1,085	$1,015	$1,085	$1,050	$1,085	$1,050	$1,085	$1,085	$1,050	$1,085	$12,810
PURCHASE COST	$	$108,300	$193,688	$260,214	$239,511	$165,230	$95,820	$75,175	$75,750	$85,684	$85,808	$72,420	$79,019	$1,536,619
TOTAL FIXED	$	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$4,643	$55,717
TOTAL VARIABLE	$	$109,350	$194,773	$261,299	$240,526	$166,315	$96,870	$76,260	$76,800	$86,769	$86,893	$73,470	$80,104	$1,549,429
DELIVERED VOLUMES AT NYMEX	$	$68,790	$77,128	$81,127	$75,081	$77,934	$70,470	$72,385	$71,400	$75,237	$75,578	$72,660	$75,919	$893,709
NET NON-GAS VARIABLE COST	$	$40,560	$117,645	$180,172	$165,445	$88,381	$26,400	$3,875	$5,400	$11,532	$11,315	$810	$4,185	$655,720
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$1.3520**	**$3.7950**	**$5.8120**	**$5.7050**	**$2.8510**	**$0.8800**	**$0.1250**	**$0.1800**	**$0.3720**	**$0.3650**	**$0.0270**	**$0.1350**	**$1.7916**
AVERAGE FIXED COST	$/Dth													$4.6431
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.1526**
TOTAL PATH COST	$/Dth													**$1.9442**

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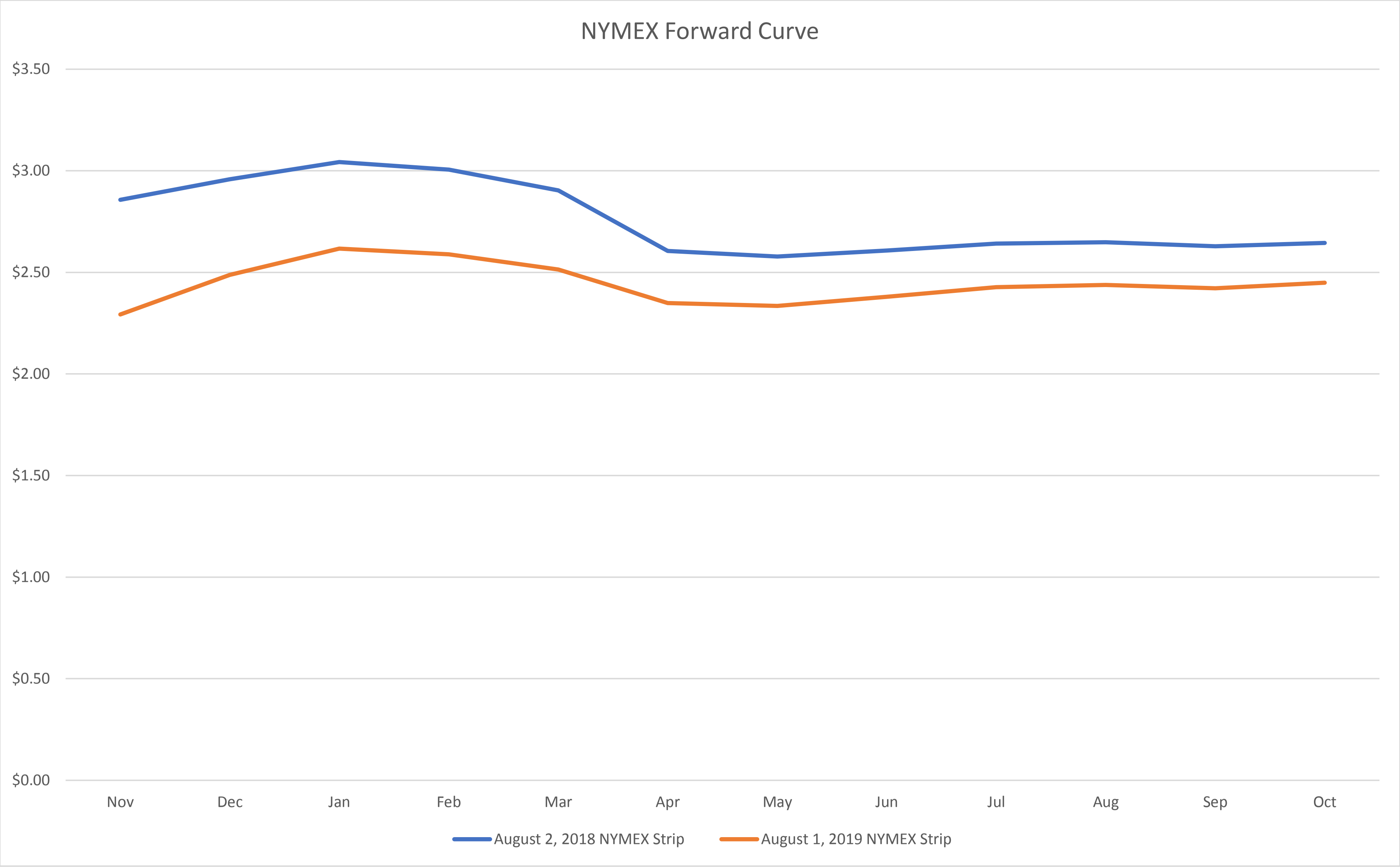
NYMEX Strip Comparison

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 2, 2018 NYMEX Strip	$2.857	$2.958	$3.043	$3.006	$2.903	$2.605	$2.578	$2.608	$2.642	$2.648	$2.629	$2.645
August 1, 2019 NYMEX Strip	$2.293	$2.488	$2.617	$2.589	$2.514	$2.349	$2.335	$2.380	$2.427	$2.438	$2.422	$2.449



Attachment EDA/SAJ-3

Attachment EDA/SAJ-3

FT-2 Operational Parameters

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

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

Effective Period: November 1, 2019 through October 31, 2020

Underground Storage:

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

November 1	95%
November 15	95%
December 1	95%
December 15	87%
January 1	77%
January 15	67%
February 1	54%
February 15	43%
March 1	32%
March 15	24%
April 1	14%

Peaking Inventory:

Inventory Level allocated on November 1, 2019 = MSQ-P
Injections are not allowed.
Minimum Inventory Levels:

November 1	100%
January 1	91%
February 1	22%
March 1	3%
April 1	0%

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

Attachment EDA/SAJ-4

Attachment EDA/SAJ-4

FT-2 Storage Variable Costs

FT-2 Storage Variable Costs 2019-2020

SLF - Weighted Average Loss Factor on Storage Withdrawals

Storage	Withdrawals	Fuel %	Fuel Vol.	Fuel Avg.
TENN 501	505,461	0.00%	0	
GSS 300170	328,615	0.00%	0	
GSS 300168	149,429	0.00%	0	
GSS 300171	183,150	0.00%	0	
GSS-TE 600045	363,327	0.00%	0	
TETCO 400515	54,941	0.63%	346	
TETCO 400221	1,152,392	1.76%	20,282	
TETCO 400185	50,430	1.76%	888	
GSS 300169	197,819	0.00%	0	
COL FSS 9630	198,876	0.00%	0	
TENN 62918	203,700	0.00%	0	
	3,388,140		21,516	**0.6350%**

WWCC - Weighted Average Commodity Cost of Storage Withdrawals

Storage	Withdrawals	Unit Cost	Cost	Average
TENN 501	505,461	$0.0087	$4,398	
GSS 300170	328,615	$0.0164	$5,389	
GSS 300168	149,429	$0.0164	$2,451	
GSS 300171	183,150	$0.0164	$3,004	
GSS-TE 600045	363,327	$0.0208	$7,557	
TETCO 400515	54,595	$0.0481	$2,626	
TETCO 400221	1,132,110	$0.0698	$79,021	
TETCO 400185	49,542	$0.0698	$3,458	
GSS 300169	197,819	$0.0164	$3,244	
COL FSS 9630	198,876	$0.0153	$3,043	
TENN 62918	203,700	$0.0087	$1,772	
	3,366,624		$115,963	**$0.0344**

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

Storage	Transported		Fuel %		Fuel Vol.	Fuel Avg.
TENN 501	505,461			1.35%	6,824	
GSS 300170	328,615		1.95%	1.35%	10,758	
GSS 300168	149,429			1.35%	2,017	
GSS 300171	183,150		1.22%	0.64%	3,392	
GSS-TE 600045	363,327		2.25%	0.64%	10,448	
TETCO 400515	54,595		1.84%	0.64%	1,346	
TETCO 400221	1,132,110			0.64%	7,246	
TETCO 400185	49,542			0.64%	317	
GSS 300169	197,819	1.95%	2.25%	0.64%	9,435	
COL FSS 9630	198,876		1.492%	0.64%	4,221	
TENN 62918	203,700			1.35%	2,750	
	3,366,624				58,754	**1.7452%**

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

Storage	Withdrawals		Unit Cost		Cost	Average
TENN 501	498,637			$0.1139	$56,795	
GSS 300170	317,857		$0.0156	$0.1139	$41,163	
GSS 300168	147,412			$0.1139	$16,790	
GSS 300171	179,758		$0.0392	$0.0615	$18,102	
GSS-TE 600045	352,879		$0.0667	$0.0615	$45,239	
TETCO 400515	53,248		$0.0557	$0.0615	$6,241	
TETCO 400221	1,124,864			$0.0615	$69,179	
TETCO 400185	49,225			$0.0615	$3,027	
GSS 300169	188,384	$0.0156	$0.0667	$0.0503	$24,980	
COL FSS 9630	194,655		$0.0175	$0.0615	$15,378	
TENN 62918	200,950			$0.1139	$22,888	
	3,307,870				$319,781	**$0.0967**

Attachment EDA/SAJ-5

Attachment EDA/SAJ-5

RFPs for PXP Phases I & II

nationalgrid

Request for Proposals ("RFP") for Asset Management Arrangements
Reissued – August 13, 2019

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for Asset Management Arrangements ("AMA") as more fully set forth below. The successful bidder ("Seller") shall have the right to optimize the assigned assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements. *Additionally, as part of this AMA, Buyer will not consider offers that include a contingent release of the downstream PNGTS asset.*

I. Provisions

Package No. 1 - AMA (PXP Phase I)

Term: November 1, 2019 through October 31, 2020.

Assets: Beginning November 1, 2019, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	10,757	11,349	Dawn	Parkway
TransCanada	FT	10,757	11,349	Parkway	East Hereford

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

Package No. 2 - AMA (PXP Phase II)

Term: November 1, 2019 through October 31, 2020.

Assets: National Grid is currently party to a precedent agreement with Portland Natural Gas Transmission System ("PNGTS") for the transportation of Gas from Dawn, Ontario to Dracut, MA via the following systems: Union Gas Limited ("Union"); TransCanada Gas Pipelines Limited ("TransCanada") and PNGTS to serve its firm gas customer requirements on Tennessee Gas Pipeline Company, L.L.C. ("Tennessee"). On May 7, 2018, PNGTS filed an application with the Federal Energy Regulatory

Commission ("FERC") to satisfy the requirements of Phase II of the Portland Xpress Project to achieve an in-service date of November 1, 2019 [CP18-479]; authorization of the necessary facilities by the FERC is a condition precedent of a transaction confirmation resulting from this RFP and necessary for the agreement between National Grid and PNGTS to become effective.

Once the agreement is effective, PNGTS will assign the corresponding upstream TransCanada capacity to National Grid and, at that time, National Grid shall also have the right to take assignment of the corresponding volume of upstream Union capacity to feed TransCanada. Following such assignments, National Grid will have transportation service agreements: with Union from Dawn to Parkway; with TransCanada from Parkway to East Hereford; and with PNGTS from East Hereford to Dracut.

Beginning November 1, 2019, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	14,948	15,771	Dawn	Parkway
TransCanada	FT	14,948	15,771	Parkway	East Hereford

<u>Asset Management Fee:</u> Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA and <u>how the Asset Management Fee will be impacted if the condition precedent related to the in-service of Phase II of the Portland Xpress Project does not occur on November 1, 2019</u>.**

<u>Provisions Applicable to Packages 1&2</u>

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

<u>Delivery Point:</u> The Delivery Point shall be the point of interconnection between TransCanada and PNGTS known as East Hereford, on the U.S. side.

<u>Gas Supply Requirements:</u> On any day during the period of **November 1, 2019 through April 30, 2020** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at East Hereford. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TransCanada. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

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

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

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

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

Form of Agreement:

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

Import/Export Reporting:

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

II. Instructions to Bidders

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

GasRFP@nationalgrid.com

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

III. Schedule (all times are Eastern Standard Time)

August 16, 2019	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 23, 2019.**

IV. Miscellaneous

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

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

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

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

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

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

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

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

John Allocca
Director of FERC Compliance and Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning
Telephone: 781-907-1639

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

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

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

Form of Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid
Package 1

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangement dated August 13, 2019, which is incorporated into and made a part hereof. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller ______ ("Seller" or "Asset Manager") and The Narragansett Electric Company d/b/a National Grid ("Buyer" or "National Grid") dated________. ***The terms of this Transaction Confirmation are binding upon execution hereof by both parties.***

Seller:

Attn: ____
Phone: ______________________________________
Fax: ____

Buyer:
The Narragansett Electric Company d/b/a National Grid
100 East Old Country Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Base Contract No.
Transporter: Union Gas Limited ("Union"); TransCanada Gas Pipelines Limited ("TransCanada").

Trader: Samara Jaffe

Contract Price: See Special Conditions below.

Term: Begin: November 1, 2019 End: October 31, 2020

Performance Obligation and Contract Quantity: See Special Conditions Below.

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

Special Conditions:

A. Definitions

"Assets" means the assigned portion of Buyer's Union and TransCanada contracts, summarized as follows:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	10,757	11,349	Dawn	Parkway
TransCanada	FT	10,757	11,349	Parkway	East Hereford

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

"Credit Support Provider" shall mean ____________.

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

"FERC" means the Federal Energy Regulatory Commission.

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

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

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

B. Gas Service and Release of Assets

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

2. **Gas Supply Requirements:**

   A. On any day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TransCanada. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

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

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

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

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

D. Nominations

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

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

E. Asset Management Fee

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

F. Credit Provisions

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

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

Exposure. shall be calculated as the sum of:

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

G. Changes in Law

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

H. Import/Export Reporting

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

Seller:	Buyer: The Narragansett Electric Company d/b/a National Grid
By: ______________________________ Name: Title: Date:	By: ______________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Form of Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid
Package 2

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangement dated August 13, 2019, which is incorporated into and made a part hereof. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller ______ ("Seller" or "Asset Manager") and The Narragansett Electric Company d/b/a National Grid ("Buyer" or "National Grid") dated________. ***The terms of this Transaction Confirmation are binding upon execution hereof by both parties.***

Seller:

Attn: ____
Phone: ____
Fax: ____

Buyer:
The Narragansett Electric Company d/b/a National Grid
100 East Old Country Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Base Contract No.
Transporter: Union Gas Limited ("Union"); TransCanada Gas Pipelines Limited ("TransCanada").
Trader: Samara Jaffe

Contract Price: See Special Conditions below.

Term: Begin: November 1, 2019 End: October 31, 2020

Performance Obligation and Contract Quantity: See Special Conditions Below.

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

Special Conditions:

A. Definitions
"Assets" means the assigned portion of Buyer's Union and TransCanada contracts, summarized as follows:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	14,948	15,771	Dawn	Parkway
TransCanada	FT	14,948	15,771	Parkway	East Hereford

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

"Credit Support Provider" shall mean _____________.

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

"FERC" means the Federal Energy Regulatory Commission.

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

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

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

B. Gas Service and Release of Assets

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

2. **Gas Supply Requirements:**

   A. On any day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TransCanada. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

      i. **Base-Load Option**: At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this delivery period.
      ii. **Daily-Call Option:** Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

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

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

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

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

D. Nominations

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

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

E. Asset Management Fee

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

F. Credit Provisions

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

Gas Daily Index.

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to National Grid, (ii) the amount of Cash held by National Grid as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of National Grid ("Letter of Credit"), and (iii) the undrawn value of each Letter of Credit ; provided, however, that the Collateral Requirement of Seller will be deemed to be zero (0) if on the relevant Valuation Date, (i) no Event of Default with respect to Seller or its Credit Support Provider has occurred and is continuing, and (ii) the guaranty provided by Seller is in full force and effect. The "Collateral Requirement" for National Grid means zero (0).

Exposure. shall be calculated as the sum of:

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

G. Changes in Law

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

H. Condition Precedent

Buyer is currently party to a precedent agreement with Portland Natural Gas Transmission System ("PNGTS") for the transportation of Gas from Dawn, Ontario to Dracut, MA via the following systems: Union; TransCanada and PNGTS to serve its firm gas customer requirements on Tennessee. On May 7, 2018, PNGTS filed an application with the FERC to satisfy the requirements of Phase II of the Portland Xpress Project to achieve an in-service date of November 1, 2019 [CP18-479]; authorization of the necessary facilities by the FERC is a condition precedent of this Transaction Confirmation to become effective.

I. Import/Export Reporting

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

Seller:	Buyer: The Narragansett Electric Company d/b/a National Grid
By: ___________________________________ Name: Title: Date:	By: ___________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Request for Proposals ("RFP") for Asset Management Arrangements
August 13, 2019

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

I. Provisions

Package No. 5 - AMA (PXP Phase I)

Term: November 1, 2019 through October 31, 2020.

Assets: Beginning November 1, 2019, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	10,757	11,349	Dawn	Parkway
TransCanada	FT	10,757	11,349	Parkway	East Hereford
PNGTS	FT	10,757	NA	Pittsburg	Dracut

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

Package No. 6 - AMA (PXP Phase II)

Term: November 1, 2019 through October 31, 2020.

Assets: National Grid is currently party to a precedent agreement with Portland Natural Gas Transmission System ("PNGTS") for the transportation of Gas from Dawn, Ontario to Dracut, MA via the following systems: Union Gas Limited ("Union"); TransCanada Gas Pipelines Limited ("TransCanada") and PNGTS to serve its firm gas customer requirements on Tennessee Gas Pipeline Company, L.L.C. ("Tennessee"). On May 7, 2018, PNGTS filed an application with the Federal Energy Regulatory

Commission ("FERC") to satisfy the requirements of Phase II of the Portland Xpress Project to achieve an in-service date of November 1, 2019 [CP18-479]; authorization of the necessary facilities by the FERC is a condition precedent of a transaction confirmation resulting from this RFP and necessary for the agreement between National Grid and PNGTS to become effective.

Once the agreement is effective, PNGTS will assign the corresponding upstream TransCanada capacity to National Grid and, at that time, National Grid shall also have the right to take assignment of the corresponding volume of upstream Union capacity to feed TransCanada. Following such assignments, National Grid will have transportation service agreements: with Union from Dawn to Parkway; with TransCanada from Parkway to East Hereford; and with PNGTS from East Hereford to Dracut.

Beginning November 1, 2019, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	14,948	15,771	Dawn	Parkway
TransCanada	FT	14,948	15,771	Parkway	East Hereford
PNGTS	FT	14,948	NA	Pittsburg	Dracut

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA and how the Asset Management Fee will be impacted if the condition precedent related to the in-service of Phase II of the Portland Xpress Project does not occur on November 1, 2019.**

Provisions Applicable to Packages 5&6

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

Delivery Point:

The Delivery Point shall be the point of interconnection between PNGTS and Tennessee Gas Pipeline Company at Dracut, MA.

Gas Supply Requirements:

On any day during the period of **November 1, 2019 through April 30, 2020** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at East Hereford. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TransCanada. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

(c) Additional Call – In addition to the Gas Supply Requirements above, on any Day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity on PNGTS that is not supplied by Union and TransCanada. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm base-load and daily call supplies.

Price:

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

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

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

Daily Call Nominations:

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

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

Form of Agreement:

National Grid will consider Proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Included in this RFP is the form of Transaction Confirmation that National Grid proposes for execution. As part of their Proposal(s), Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction

Confirmation including, but not limited to, language related to FERC, the CFTC and any other applicable regulatory body.

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

II. Instructions to Bidders

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

GasRFP@nationalgrid.com

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

III. Schedule (all times are Eastern Standard Time)

August 16, 2019	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 23, 2019.**

IV. Miscellaneous

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

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

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

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

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

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

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

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

John Allocca
Director of FERC Compliance and Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning

Telephone: 781-907-1639

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

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

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

nationalgrid

Form of Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid
Package 5

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangement dated August 13, 2019, which is incorporated into and made a part hereof. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller ______ ("Seller" or "Asset Manager") and The Narragansett Electric Company d/b/a National Grid ("Buyer" or "National Grid") dated________. ***The terms of this Transaction Confirmation are binding upon execution hereof by both parties.***

Seller:

Attn: ____
Phone: ______________________________________
Fax: ____

Buyer:
The Narragansett Electric Company d/b/a National Grid
100 East Old Country Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Base Contract No.
Transporter: Union Gas Limited ("Union"); TransCanada Gas Pipelines Limited ("TransCanada"); Portland Natural Gas Transmission System ("PNGTS").

Trader: Samara Jaffe

Contract Price: See Special Conditions below.

Term: Begin: November 1, 2019 End: October 31, 2020

Performance Obligation and Contract Quantity: See Special Conditions Below.

Delivery Point(s): The Delivery Point shall be the point of interconnection between PNGTS and Tennessee Gas Pipeline Company known as Dracut.

Special Conditions:

A. Definitions

"Assets" means the assigned portion of Buyer's Union and TransCanada contracts, summarized as follows:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	10,757	11,349	Dawn	Parkway
TransCanada	FT	10,757	11,349	Parkway	East Hereford
PNGTS	FT	10,757	NA	Pittsburg	Dracut

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

"Credit Support Provider" shall mean _____________.

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

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by

Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

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

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

B. Gas Service and Release of Assets

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

2. **Gas Supply Requirements:**

   A. On any day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TransCanada. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

   iii. **Additional Call –** In addition to the Gas Supply Requirements above, on any Day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity on PNGTS that is not supplied by Union and TransCanada. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm base-load and daily call supplies.

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

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

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

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

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

D. Nominations

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

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

E. Asset Management Fee

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

F. Credit Provisions

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

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

Exposure. shall be calculated as the sum of:

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

G. Changes in Law

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

H. Import/Export Reporting

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

Seller: By: ______________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company d/b/a National Grid By: ____________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Form of Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid
Package 6

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangement dated August 13, 2019, which is incorporated into and made a part hereof. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller ______ ("Seller" or "Asset Manager") and The Narragansett Electric Company d/b/a National Grid ("Buyer" or "National Grid") dated________. ***The terms of this Transaction Confirmation are binding upon execution hereof by both parties.***

Seller:

Attn: ____
Phone: ____
Fax: ____

Buyer:
The Narragansett Electric Company d/b/a National Grid
100 East Old Country Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Base Contract No.
Transporter: Union Gas Limited ("Union"); TransCanada Gas Pipelines Limited ("TransCanada"); Portland Natural Gas Transmission System ("PNGTS").
Trader: Samara Jaffe

Contract Price: See Special Conditions below.

Term: Begin: November 1, 2019 End: October 31, 2020

Performance Obligation and Contract Quantity: See Special Conditions Below.

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

Special Conditions:

A. Definitions

"Assets" means the assigned portion of Buyer's Union and TransCanada contracts, summarized as follows:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	14,948	15,771	Dawn	Parkway
TransCanada	FT	14,948	15,771	Parkway	East Hereford
PNGTS	FT	14,948	NA	Pittsburg	Dracut

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

"Credit Support Provider" shall mean _____________.

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

"FERC" means the Federal Energy Regulatory Commission.

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

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

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

B. Gas Service and Release of Assets

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

2. **Gas Supply Requirements:**

   A. On any day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TransCanada. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

      iii. **Additional Call –** In addition to the Gas Supply Requirements above, on any Day during the period of November 1, 2019 through April 30, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity on PNGTS that is not supplied by Union and TransCanada. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm base-load and daily call supplies.

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

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

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

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

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

D. Nominations

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

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

E. Asset Management Fee

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

F. Credit Provisions

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

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to National Grid, (ii) the amount of Cash held by National Grid as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of National Grid ("Letter of Credit"), and (iii) the undrawn value of each Letter of Credit ; provided, however, that the Collateral Requirement of Seller will be deemed to be zero (0) if on the relevant Valuation Date, (i) no Event of Default with respect to Seller or its Credit Support Provider has occurred and is continuing, and (ii) the guaranty provided by Seller is in full force and effect. The "Collateral Requirement" for National Grid means zero (0).

Exposure. shall be calculated as the sum of:

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

G. Changes in Law

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

H. Condition Precedent

Buyer is currently party to a precedent agreement with Portland Natural Gas Transmission System ("PNGTS") for the transportation of Gas from Dawn, Ontario to Dracut, MA via the following systems: Union; TransCanada and PNGTS to serve its firm gas customer requirements on Tennessee. On May 7, 2018, PNGTS filed an application with the FERC to satisfy the requirements of Phase II of the Portland Xpress Project to achieve an in-service date of November 1, 2019 [CP18-479]; authorization of the necessary facilities by the FERC is a condition precedent of this Transaction Confirmation to become effective.

I. Import/Export Reporting

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

Seller: By: ______________________________________	Buyer: The Narragansett Electric Company d/b/a National Grid By: ____________________________________

Name: Title: Date:	Name: John V. Vaughn Title: Authorized Signatory Date:

Attachment EDA/SAJ-6

Attachment EDA/SAJ-6

RFP for AMA Dracut to Citygate

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

Reissued - August 13, 2019

The Narragansett Electric Company d/b/a National Grid ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an AMA (Package No. 4) as more fully set forth below. The successful bidder(s) ("Seller") shall have the right to optimize the assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements. **Bidders may bid on all or a portion of the MDQ for the Package.**

Package No. 4 – AMA (Dracut to City Gate)

I. Provisions

Term: November 1, 2019 through October 31, 2020.

Assets: During the Term, Buyer shall release FT-A capacity with Tennessee Gas Pipeline Company L.L.C. ("TGP"), having primary receipts at Dracut, MA (pin number 412538) and primary deliveries in Zone 6 at the point(s) of interconnection between TGP and Buyer's facilities in Cranston, RI, NY (pin number 420750) and Lincoln, RI (pin number 420758). The maximum delivered quantity of the Assets is **22,300 dt/day** ("MDQ"), which is allocated as 20,000 dt/day at Cranston and 2,300 dt/day at Lincoln.

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

Delivery Point: The point of interconnection between TGP and Buyer's facilities at Cranston and Lincoln.

Gas Supply Requirements: On any day during the period of **December 1, 2019 through April 30, 2020**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account.

Price: For the first ten (10) days on which Buyer exercises the call option pursuant to Gas Supply Requirements, the Price shall be equal to the price for Tennessee, Zone 6, Delivered North - as published in *Platts Gas Daily Daily Price Survey* for the day of flow, plus the variables to transport Gas to the Delivery Point. After Buyer has exercised the first 10 days of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to Tennessee, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* $0.10, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

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

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

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

II. Instructions to Bidders

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

GasRFP@nationalgrid.com.

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals should include: **(a) Seller's proposed Asset Management Fee and/or Reservation Fee (b) any proposed**

exceptions to the Transaction Confirmation attached hereto for Package No. 1 and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.

III. Schedule (all times are Eastern Time)

August 16, 2019	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 23, 2019.**

IV. Form of Agreement

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

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

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

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

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

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

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

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

John Allocca
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Liz Arangio
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nationalgrid

Asset Management Arrangement (Package No. 4)
Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid

TRANSACTION CONFIRMATION

		Date: ____________ Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangements dated August 13, 2019, which is incorporated into and made a part hereof. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________. ***This Transaction Confirmation will not become binding until executed by both parties.***

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

Contract Price: See Special Conditions Section C Below

Term: Begin: November 1, 2019 End: October 31, 2020

Performance Obligation and Contract Quantity: See Special Conditions Below

Delivery Point(s): The point of interconnection between Tennessee and Buyer's facilities at Cranston, RI and Lincoln, RI.

Special Conditions:

A. Definitions

"Assets" means Buyer's FT-A Contracts with Tennessee having primary receipts at Dracut, MA (pin number 412538) and primary deliveries in Zone 6 the point(s) of interconnection between Tennessee and Buyer's facilities in Cranston, RI, NY (pin number 420750) and Lincoln, RI (pin number 420758). The maximum delivered quantity of the Assets is **22,300 dt/day** ("MDQ"), which is allocated as 20,000 dt/day at Cranston and 2,300 dt/day at Lincoln.

"Credit Support Provider" means__________________________.

"CFTC" means the Commodity Futures Trading Commission.

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

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

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by

Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

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

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

B. Gas Service and Capacity Release

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

- **b. Daily Call:** On any day during the period of **December 1, 2019 through April 30, 2020**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point(s).

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

C. Price: For the first ten (10) days on which Buyer exercises the call option pursuant to Gas Supply Requirements, the Price shall be equal to the price for Tennessee, Zone 6, Delivered North - as published in *Platts Gas Daily Daily Price Survey* for the day of flow, plus the variables to transport Gas to the Delivery Point. After Buyer has exercised the first 10 days of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to Tennessee, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* $0.10, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

D. Nominations

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

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

E. Asset Management Fee

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

F. Credit Provisions

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

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

Exposure. shall be calculated as the sum of:

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

G. Asset Management Arrangement

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

H. Changes in Law

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

Seller: By: ____________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company d/b/a National Grid By:___________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Attachment EDA/SAJ-7

Attachment EDA/SAJ-7

RFP for Citygate Deliveries

nationalgrid

Request for Proposals ("RFP") for Firm Gas Supply May 23, 2019

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for Firm Gas Supply as more fully set forth below. The winning bidder(s) ("Seller(s)") shall deliver the required gas supply to the Delivery Point(s) described below.

National Grid's award of the gas supply services under this RFP and execution of any resulting Transaction Confirmations are contingent upon receipt by National Grid of (1) an indication of support from the Rhode Island Division of Public Utilities Commission ("PUC"). National Grid shall use due diligence to obtain such Approvals by May 31, 2020. In the event that National Grid does not obtain such Approvals by May 31, 2020, National Grid reserves the right to rescind any award hereunder. Successful Bidders agree to take all reasonable steps, at National Grid's request, to support National Grid in obtaining the Approvals.

Buyer:	The Narragansett Electric Company d/b/a National Grid.
Term:	December 1, 2019 through March 31, 2024. * As part of this RFP, National Grid is seeking an extension option of the Term for up to 100% of the MDQ and MSQ defined in the Gas Supply Requirements section of this RFP for a period of up to three (3) years, provided that Buyer notifies Seller of such election in writing no less than twenty-four (24) months prior to the expiration of the initial Term. Bidders able to offer additional extension rights, including but not limited to a right of first refusal or optional permanent release of interstate pipeline capacity should indicate so with their offer.
Delivery Point(s):	The Delivery Point(s) shall be a point of interconnection between Buyer's Rhode Island facilities and either Tennessee or Algonquin.

As part of their bid, Bidders must demonstrate they have *primary* firm capacity to each of Buyer's Delivery Point(s) for which they are submitting an offer using Exhibit A included hereto and/or an explanation of the priority of service to be used in meeting Buyer's Gas Supply Requirements if selected.

Gas Supply Requirements: On any day during the months of December through March of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to 17,000 dth/day ("MDQ") at the Delivery Point. Such right shall be limited to a maximum seasonal quantity of 620,000 dth ("MSQ") during the Term. *Bidders able to offer pricing options and flexibility for National Grid to increase its MSQ throughout each contract season should indicate so with their bid.*

Price: The commodity price for Gas called on any day will be equal to Platts Gas Daily – Daily Price Survey ($MMBtu) Midpoint Algonquin City-Gates or Tennessee Zone 6, as applicable.

Reservation Charge: To be proposed by Bidder.

Daily Call Nominations: For Daily Calls at the Delivery Point, Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested.

As part of their offer, Bidders **must** indicate whether nominations must be ratable through weekends and holidays; during the bid evaluation period, National Grid reserves the right to give preference to nominations that need not be ratable.

Damages: On any day Buyer nominates gas pursuant to an agreement resulting from this RFP and Seller fails to deliver the nominated quantity, Seller shall reimburse Buyer for each undelivered dth an amount equal to the greater of Buyer's Cover costs or 150% of the greater of Gas Daily Midpoint for Algonquin City-Gates or Tennessee Zone 6 per dth for the applicable day.

Affidavit of Primary Firm Delivery: Bidder must demonstrate that it has primary firm capacity to each Delivery Point(s) at which they are offering firm service and must provide an affidavit in the form included hereto as Exhibit A *and/or* a written explanation of the priority of service it will utilize to serve a Buyer's rights under a Transaction Confirmation resulting from this RFP.

II. Instructions to Bidders

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

GasRFP@nationalgrid.com

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

III. Schedule (all times are Eastern Standard Time)

June 5, 2019	Proposals must be received by National Grid by 12:00 PM. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on June 7, 2019.**

June 7, 2019	National Grid will endeavor to select a Proposal and parties will confirm deal in writing by 5:00 PM.

IV. Miscellaneous

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

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

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

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

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

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

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

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

John Allocca
Director of FERC Compliance & Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning
Telephone: 781-907-1639

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist of FERC Compliance & Contracting

Telephone: 516-545-5463

Exhibit A

AFFIDAVIT OF FIRM DELIVERY
2019-2024 GAS SUPPLY

An officer of Seller providing delivered supplies to The Narragansett Electric Company d/b/a National Grid, as it pertains to the RFP issued May 23, 2019, must complete the following Affidavit in order to submit a qualifying bid.

AFFIDAVIT OF FIRM TRANSPORTATION AND/OR DELIVERY CAPACITY

STATE OF ____

CITY OF ____

NAME ____,

Being duly sworn, says:

I am ________________________________ (specify Title of Officer)

of ________________________________ (specify Name of Supplier)

And, I attest that:

As Seller of natural gas to National Grid for up to _________ dekatherms per day of Firm gas supplies during the period **December 1, 2019 through March 31, 2024**, Seller has in place one or more executed contract(s) with
____ Pipeline,

providing non-recallable firm transportation with primary delivery point capacity of
____ Dt/Day, (specify volume)
to ____________________________________ (specify delivery point location).
The Pipeline contract number(s) related to this capacity are ______________ and have a primary term end date of _________ [if the primary end date expires before the end date of the term of your offer, please explain ROFR, extension rights, etc. of the associated capacity].
*[Misc. if applicable]*____
____
____
____
____.

The above-mentioned capacity shall be dedicated specifically to supporting the sale to National Grid as it pertains to the RFP issued May 23, 2019.

By: ____________________________________

Title: ____________________________________

Dated: __________________________

Attachment EDA/SAJ-8

REDACTED

Attachment EDA/SAJ-8

Incremental Portable LNG Storage and Vaporization

Request for Proposals

For

Non-Pipeline Solutions on behalf of The Narragansett Electric Company d/b/a National Grid

May 17, 2019

REDACTED

Request for Proposals

Table of Contents

19. Transaction Confirmation
20. PS-05-01 – Safety Critical Activities Procedure Categorization Risk Ranking Tool
21. PS-05-07 – Human Factors Implementation Plan for Safety in Design
22. PS-05-08 – Safety in Design Specification for Incorporating Human Factors
23. CNG Addendum
24. Old Mill Lane Site Layout

I Introduction and Overview

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company") is requesting proposals for non-pipeline solutions utilizing either temporary liquid natural gas ('LNG") injection storage or compressed natural gas ("CNG") injection services on behalf of its customers in Rhode Island during the winters 2019/2020-2020/2021 period at the following locations:

1) The Company's property at 135 Old Mill Lane, Portsmouth, RI 02871; ***and***
2) A location to be identified by the vendor as part of their proposal that is able to assist in serving the peak day requirements of firm gas customers in the following locations:

City	Postal Code
Middletown, RI	02842
Newport, RI	02840
Newport, RI	02841
Portsmouth, RI	02871

National Grid reserves the right not to award this Request for Proposal ("RFP").

A. Objective of the Request for Proposals

The purpose of this RFP is to solicit, evaluate and select, through a competitive bidding process, agreements for LNG injection storage services and/or CNG injection services to the locations described herein. Bidders must submit the requested documentation detailed in each of the Exhibits incorporated herein in order to be considered for a definitive agreement resulting from this RFP, as well as a statement of work and description of services to be used, including materials, equipment, apparatus, tools, labor, services and facilities necessary to perform all work necessary to meet National Grid's requirements. The agreement between National Grid and the successful bidder shall be documented under a duly executed Transaction Confirmation, in the form attached hereto **(Exhibit 19)**.

B. Scope of Work

For LNG solutions on the Company's property *only*, it is National Grid's intention to contract for and provide supplies of both LNG and third-party trucking assets to facilitate the scope of work described herein. The awarded contractor shall provide all materials, equipment, apparatus, tools, labor, services and facilities necessary to perform all the work in accordance with a Transaction Confirmation resulting from this solicitation as follows:

1. The Narragansett Electric Company d/b/a National Grid – Old Mill Lane

The successful bidder shall provide either a temporary LNG or CNG injection service to National Grid at the Company's property at 135 Old Mill Lane in Portsmouth, RI. The site is currently approved and configured for LNG storage and injection services by both National Grid's process safety and the town of Portsmouth; the preferred layout from the previous year's operations is provided as **Exhibit 24.** Services to be provided include all necessary equipment, labor and related services required to meet National Grid health, safety and operational requirements by the service start date of December 1, 2019. For an LNG solution, this shall include but is not limited to the following:

- Mobilize and maintain all necessary storage units, portable pipe supports, vaporizers and truck unloading manifolds, as well as all necessary piping, connections and related ancillary items to complete fabrication and commissioning of the resulting system no later than the week of November 15, 2019 and complete construction of the same to achieve ready for operation status December 1, 2019;
- Enter remotely monitored standby operation beginning each of December 1, 2019, through and including March 31, 2020, and December 1, 2020, through and including March 31, 2021, including all equipment, and manpower required to perform;
- Upon injection service activation, the successful bidder shall meet National Grid's requirements of up to 300 dth per hour of gas injection service into the Company's 99 psig system over a duration of nine (9) hours winter peak demand –defined as the period from 6:00 am to 12:00 pm and 5:00 pm to 8:00 pm, unless otherwise specified by National Grid's Gas System Operator ("GSO"), and shall continue to provide such services until shutdown notification is issued by GSO. Ancillary items related to the mobilization and maintenance of the LNG injection service shall include the availability and presence of a subject matter expert during a process hazard analysis (PHA) and Pre-Startup Safety Review (PSSR).
- National Grid may, but is not required to, provide notice of activation shall be issued by GSO at least 72 hours before expected ambient

temperatures of 20 degrees F or below, upon which time the successful bidder will dispatch qualified trained personnel to the site for start-up, with injection service activation to occur at 10 degrees F or below, unless specified otherwise by GSO;

- Successful bidder shall provide operating procedures, including but not limited to start-up, normal operations, shut-down, emergency shut-down, and shall include the availability and presence of a subject matter expert during human factors analysis of these procedures.
- Demobilization to occur after March 31, 2021, subject to National Grid's extension option:

    - On or before each of April 30, 2021 and April 30, 2022, Narragansett shall have the right to renew a contract resulting from this RFP at the same terms and conditions for the period(s) commencing December 1, 2021, through and including March 31, 2022 and December 1, 2022, through and including March 1, 2023.

2. Vendor Secured Property

In addition to the project described in Section I.B.1 of this RFP, the Company is also seeking proposals for either a temporary LNG or CNG injection service into the Company's distribution system at a location to be identified by the vendor as part of their proposal. The proposed site and project type must be able to assist National Grid in meeting its peak day requirements in the following locations:

City	Postal Code
Middletown, RI	02842
Newport, RI	02840
Newport, RI	02841
Portsmouth, RI	02871

For all proposals submitted pursuant to this Section I.B.2, vendor shall be solely responsible for securing all necessary gas supplies, including LNG or CNG, as well as transportation assets necessary to move such supplies to the project location. In addition to the acquisition of land and natural gas supplies, services to be provided by the vendor shall include all other necessary equipment, labor and related services as required to meet National Grid's operational requirements by the service start date of December 1, 2019 through March 31, 2021, including but not limited to the following:

- Mobilize and maintain all necessary storage units and/or trailers, portable pipe supports, vaporizers (as necessary) and truck unloading manifolds, as well as all necessary piping, connections and related ancillary items to complete fabrication and commissioning of the resulting system no later than the week of November 15, 2019 and complete construction of the same to achieve ready for operation status December 1, 2019;

- Enter remotely monitored standby operation beginning each of December 1, 2019, through and including March 31, 2020, and December 1, 2020, through and including March 31, 2021, including all equipment, and manpower required to perform;
- Upon injection service activation, the successful bidder shall meet National Grid's requirements of up to 200 dth per hour of gas injection service into the Company's 50 psig system for a maximum daily volume of 2,500 dth unless otherwise specified by GSO and shall continue to provide such services until shutdown notification is issued by GSO.
- National Grid may, but is not required to, provide notice of activation shall be issued by GSO at least 72 hours before expected ambient temperatures of 20 degrees F or below, upon which time the successful bidder will dispatch qualified trained personnel to the site for start-up, with injection service activation to occur at 10 degrees F or below, unless specified otherwise by GSO;
- On or before each of April 30, 2021 and April 30, 2022, Narragansett shall have the right to renew a contract resulting from this RFP at the same terms and conditions for the period(s) commencing December 1, 2021, through and including March 31, 2022 and December 1, 2022, through and including March 1, 2023.

C. Compliance with National Grid's Procedures and Requirements

Bidders shall provide, where necessary, completed Exhibits along with their proposals; failure to provide completed exhibits and/or demonstration of compliance with National Grid's requirements may result in a bid being precluded from consideration. Additionally, the recipient of an award resulting from this RFP shall maintain compliance with National Grid's policies and procedures in accordance with each of the Exhibits incorporated hereto for the duration of an agreement resulting from this RFP.

ISNetworld Bidders shall use due diligence to subscribe to and receive an acceptable rating from ISNetworld for their health, safety and environmental oversight and review for the duration of the Agreement resulting from this RFP; acceptable shall be considered a rating by ISN of "C" or higher.
http://www.isnetworld.com/isn/asp/ISNMainFrameSet.asp

Waiver of this provision shall be granted on a non-discriminatory basis.

Emergency

Contact: Bidder shall provide National Grid with a current list of 24 hour Emergency Contacts and provide updates as necessary during the term of the Agreement.

D. Proposals – Pricing Arrangements and RFP Evaluation Criteria

National Grid requests that bidders submit pricing options in the format included as **Exhibit 18**. Bidders' demonstrating compliance with Company's Safety, Procurement and Risk policies shall be evaluated as a threshold matter. Such compliance shall be assessed by Company's Safety, Procurement and Risk Organizations, respectively. Information provided to ISNetworld and information provided pursuant to each of the **Exhibits** will be reviewed by Company's Safety, Risk and Procurement Organizations. Bidders may also include a CV or other available information regarding experience and qualifications that will enhance the success of their project through design, engineering and construction associated with the Scope of Work.

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

At National Grid we are always seeking to improve our reputation as a sustainable and responsible company. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to both safety and the protection and enhancement of the environment and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities for improvement. In furtherance of this goal, National Grid has developed the "Supplier Code of Conduct" which describes our company's values and is incorporated into this RFP as **Exhibit 17**.

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. National Grid expects all of its suppliers to execute a Supplier Ethics Certification Statement. Through this certification statement, you are confirming that you have read and understand the Global Supplier Code of Conduct and that you will communicate the same information to all of your employees and any subcontractors that you retain on behalf of National Grid. **This certification statement attached hereto as Exhibit 8 needs to be signed prior to performing any work for National Grid.**

II General Procedures

A. Submission of Proposals

Proposals must be submitted electronically. National Grid reserves the right to reject any proposal at its discretion. All proposals must be sent to the National Grid contacts listed below and must include contact information in the event that National Grid has questions related to the Proposal.

Should bidder have any questions, they must submit them to the National Grid contacts listed below via email. All questions and responses will be distributed to all potential bidders.

National Grid Contacts:

John E. Allocca
Director Gas Contracting and Compliance
100 E. Old Country Road
Hicksville, NY 11801
Telephone: (516) 545-3108
Email address: john.allocca@nationalgrid.com

Elizabeth D. Arangio
Director Gas Supply Planning
40 Sylvan Road E1
Waltham, MA 02451
Telephone: (781) 907-1639
Email address: elizabeth.arangio@nationalgrid.com

Samara Jaffe
Lead Program Manager
100 E. Old Country Road
Hicksville, NY 11801
Telephone: (516) 545-5408
Email address: samara.jaffe@nationalgrid.com

Janet A. Prag
Contract Specialist
100 E. Old Country Road
Hicksville, NY 11801
Telephone: (516) 545-5463
Email address: janet.prag@nationalgrid.com

B. Schedule

June 5, 2019	Prospective bidders must contact Samara Jaffe by this date at (516) 545-5408 to schedule site visits at the Old Mill

	Lane location. *All visits must be scheduled and completed in advance of the offer submission deadline.* ***Site visits are expected to be conducted on June 12.***
June 20, 2019	Proposals must be submitted ***electronically*** to National Grid by 5:00 PM EST.
June 27, 2019	National Grid shall endeavor to make a preliminary selection and will confirm with the selected vendor its intention to continue negotiations for services.

C. Confidentiality

A bidder may request that specific information contained in or relative to its proposal be treated by National Grid on a confidential basis. Such a request shall be clearly stated on every page of the portion of the proposal on which confidential information may appear and identify the specific information sought to be protected. National Grid and its representatives shall take reasonable steps to protect the information that is clearly identified as confidential from disclosure to third parties. Bidders should understand that National Grid might deem it necessary to disclose non-proprietary information regarding the RFP and/or to disclose confidential information in connection with any necessary submission to the appropriate regulatory authorities. Upon request by bidder, National Grid shall request that information designated as confidential by the bidder be treated as confidential and proprietary in accordance with the provisions of applicable laws and regulations and protected from disclosure to third parties. National Grid will request, but cannot ensure that such treatment will be granted by any of these regulatory authorities.

In no event shall National Grid be liable for damage resulting from an inadvertent disclosure of confidential information during the period of review and analysis of proposals, during subsequent contract negotiations or from disclosure mandated by any relevant regulatory authority.

D. Company's Rights

National Grid reserves the right to reject any and all bids or to terminate this RFP process at its sole discretion. National Grid may elect to delay all or part of the contract award schedule and to request re-bids if necessary. The issuance of this RFP in no way obligates National Grid to negotiate a contract with any bidder. National Grid reserves the right to negotiate with any bidder any provision of its bid or contract proposal.

National Grid shall be under no obligation to accept the lowest cost proposal or to return any proposals or materials submitted in response to the RFP. National Grid reserves the right to select all or portions of any completed bids. Proposals will be evaluated on the basis of quantitative and qualitative factors at National Grid's sole discretion. National Grid reserves the right to purchase services at any time from any source outside of the context of this RFP.

We look forward to receiving your proposal.

Exhibit 18
Pricing Proposal

Description	Cost
Monthly Lease for Equipment	
Mobilization/Demobilization Charge(s)	
Technician Cost	
Commodity Charges (as applicable)	

Exhibit 19
Transaction Confirmation

Date:

This Transaction Confirmation for Liquid Natural Gas service is entered into by and between The Narragansett Electric Company d/b/a National Grid and ___________ ("Contractor") for services further described herein.

Scope of Work: (from RFP and Contractor's proposal)

Pricing: (from Exhibit 18)

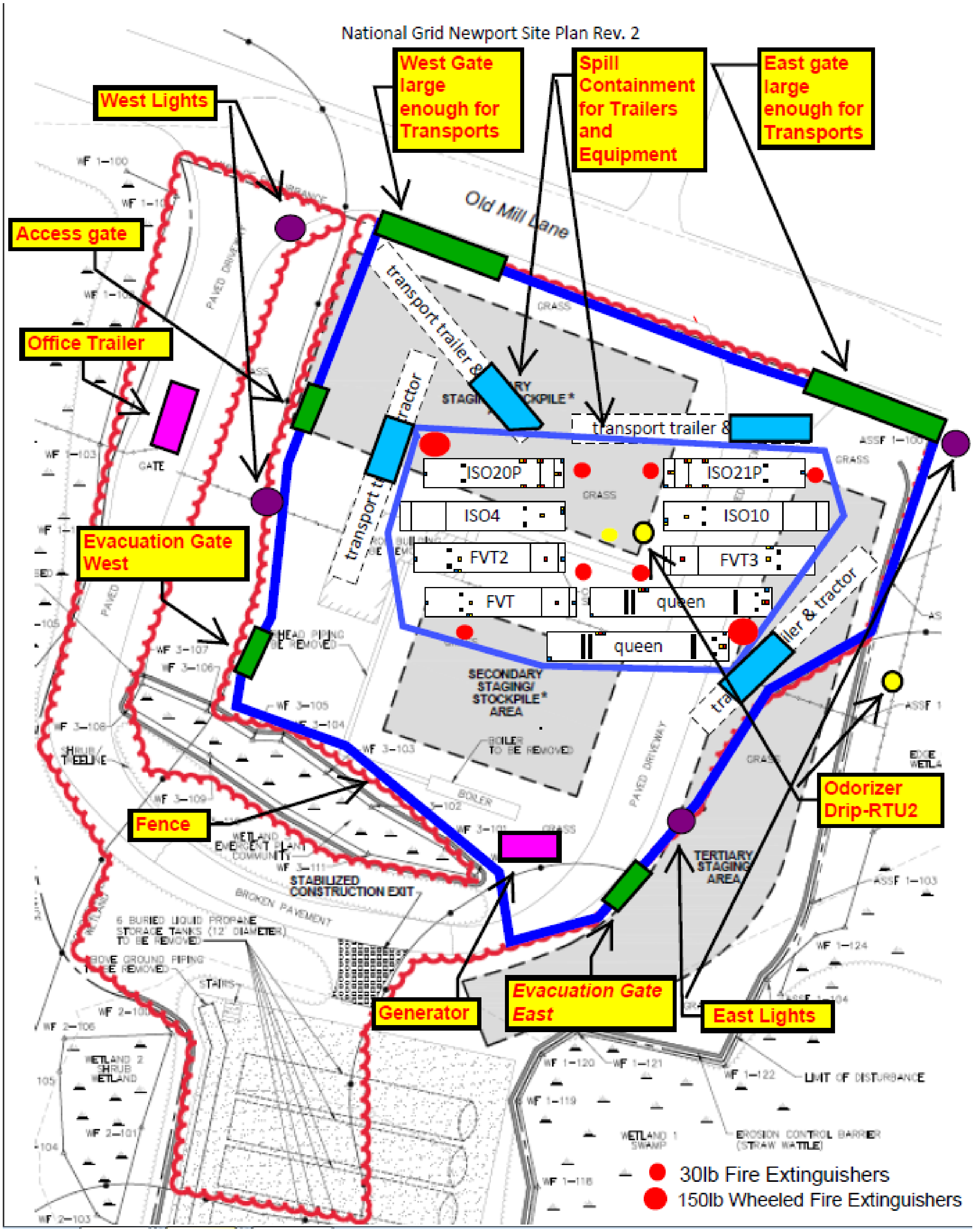
Invoicing and Payment: Contractor shall invoice National Grid monthly for services rendered within five (5) business days from the close of the month such services were provided.

Special Conditions: This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposals for Non-Pipeline Solutions on behalf of The Narragansett Electric Company d/b/a National Grid, May 17, 2019 and the Exhibits attached thereto, which are incorporated into and made a part hereof.

Agreed to as of the date first written above by:

	The Narragansett Electric Company d/b/a National Grid
By: ______________________________	**By:** ______________________________
Name: ___________________________	**Name:** ___________________________
Title: ____________________________	**Title:** ____________________________

Exhibit 24
Old Mill Lane Site Layout



REDACTED

[redacted]

Equipment Rental and Support Services Agreement

This Equipment Rental and Support Services Agreement (this "Agreement") is entered into this 14 th day of August 2019 (the "Effective Date") by and between Prometheus Energy Group Inc., a Delaware corporation ("Prometheus") and its affiliates, and The Narragansett Electric Company d/b/a National Grid ("Customer"). Prometheus and Customer are sometimes hereinafter referred to individually as "Party" and collectively as the "Parties".

Recitals

A. Prometheus is engaged in the business of providing natural gas storage and fueling solutions which include the rental of LNG equipment and operational support services.

B. Customer issued a Request for Proposals on May 17, 2019 seeking proposals for non-pipeline solutions on behalf of its customers in Rhode Island at locations including Customer's facility located at 135 Old Mill Lane in Portsmouth, RI, ("RFP") that would enable Customer to achieve its peak hour requirements during the months of December through March via gas injection services into Customer's 99 psig system.

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

[redacted]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed on the date set forth above.

The Narragansett Electric Company
d/b/a National Grid.

By: _________________________

Name: _________________________
John V. Vaughn

Title: Authorized Signatory

Prometheus Energy Group, Inc. & affiliates

By: _________________________

Name: Jim Aivalis

Title: COO

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

Attachment EDA/SAJ-9

Attachment EDA/SAJ-9

RFP for AMA Dawn to Tennessee Zone 6

nationalgrid

Request for Proposals ("RFP") for Asset Management Arrangement
Reissued -August 13, 2019

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

Package No. 3 – AMA (Dawn-Waddington-Zone 6)

I. Provisions:

Term: November 1, 2019 through October 31, 2020.

Delivery Period: November 1, 2019 through and including March 31, 2020.

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

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

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

Please see table below for contract details.

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

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

Gas Supply Requirements: On any day during the period of **November 1, 2019 through March 31, 2020** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the *Tennessee Delivery Point.* The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union, TransCanada, Iroquois and Tennessee. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

Additional Call – In addition to the Gas Supply Requirements above, on any Day during the period of November 1, 2019 through March 31, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity of each of the Iroquois and Tennessee Assets at the primary Delivery Point(s) under each such released Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm Base-Load and daily call supplies (*i.e.*, Buyer's right to request gas at the Iroquois or Tennessee Delivery Point pursuant to these Gas Supply Requirements provisions and under this Additional Call provision shall be reduced by quantities requested at any upstream Delivery Point).

Nominations:

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

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

Price:

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

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

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

Asset Management Fee:

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

Form of Agreement:

Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB

Contract or ISDA Gas Annex. Included with this RFP is the form of Transaction Confirmation that National Grid proposes for execution. **As part of their Proposal, Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation.**

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

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

II. Instructions to Bidders:

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

GasRFP@nationalgrid.com.

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

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

August 16, 2019	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 23, 2019.**

V. Form of Agreement:

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

Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the CSA.

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

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

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

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

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

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

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

John Allocca
Director of FERC Compliance and Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning
Telephone: 781-907-1639

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

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

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

nationalgrid

Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid

TRANSACTION CONFIRMATION

Date: ____________

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposals for Asset Management Arrangements dated August 13, 2019. This Transaction Confirmation is subject to the Base Contract between Seller and Buyer, dated ________. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:

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

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

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

Term: Begin: November 1, 2019 **End: October 31, 2020**

Performance Obligation and Contract Quantity: See Special Conditions below.

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

Special Conditions:

A. Definitions

"Assets" means the Agreements summarized as follows:

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

"CFTC" shall mean the Commodities Futures Trading Commission.

"Credit Support Provider" means__________________________.

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

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

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

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

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

B. Gas Service and Capacity Assignment

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

A. On any day during the period of November 1, 2019 through March 31, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Tennessee Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union, TransCanada, Iroquois and Tennessee. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

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

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

iii. Additional Call – In addition to the Gas Supply Requirements set forth in Special Condition B(2)(A) of this Transaction Confirmation, on any Day during the period of November 1, 2019 through March 31, 2020 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity of each of the Iroquois and Tennessee Assets at the primary Delivery Point(s) under each such released Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm base-load and daily call supplies (i.e., Buyer's right to request gas at the Iroquois or Tennessee Delivery Point(s) pursuant to these Gas Supply Requirements provisions and under this Additional Call provision shall be reduced by quantities requested at any upstream Delivery Point).

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

C. Nominations

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

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

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

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

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

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

E. Asset Management Fee

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

F. Credit Provisions

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

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

"Exposure" shall be calculated as the sum of:

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

G. Import/Export Reporting

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

H. Changes in Law

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

Seller:	Buyer: The Narragansett Electric Company d/b/a National Grid

By: ____________________________________ Name: Title: Date:	By:____________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Attachment EDA/SAJ-10

Attachment EDA/SAJ-10

RFP for AMA TCo Broadrun to Hanover

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

August 13, 2019

The Narragansett Electric Company d/b/a National Grid ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an AMA (Package No. 7) as more fully set forth below. The successful bidder(s) ("Seller") shall have the right to optimize the assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

Package No. 7 – AMA (TCo – Broadrun to Hanover)

I. Provisions

Term: November 1, 2019 through October 31, 2020.

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

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

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

Gas Supply Requirements: On any day during the period of **November 1, 2019 through April 15, 2020**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account.

Price: The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu)

	Midpoint for TCo Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.
Daily Call Nominations:	Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).
Asset Management Fee:	Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal, Bidders must specify the Asset Management Fee to be paid to Buyer.**

II. Instructions to Bidders

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

GasRFP@nationalgrid.com.

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

III. Schedule (all times are Eastern Time)

August 16, 2019	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 23, 2019.**

IV. Form of Agreement

National Grid will consider proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active

NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

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

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

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

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

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

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

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

John Allocca
Director of FERC Compliance and Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning
Telephone: 781-907-1639

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

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

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

nationalgrid

Asset Management Arrangement (Package No. 7)
Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid

TRANSACTION CONFIRMATION

Date: ____________
Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangements dated August 13, 2019, which is incorporated into and made a part hereof. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:
____
Attn:____
Phone:__
Fax:____
Base Contract No. _______
Transporters: ____
Transporters Contract Number: ____
Trader: _

BUYER:
The Narragansett Electric Company d/b/a National Grid
100 East Old County Road
Hicksville, New York 11801
Attn: Contract Administration
Phone: (516) 545-6068
Fax: (516) 545-5466
Base Contract No.
Transporters: Columbia Gas Transmission L.L.C. ("TCo")
Trader: Samara Jaffe

Contract Price: See Special Conditions Section C Below

Term: Begin: November 1, 2019 End: October 31, 2020

Performance Obligation and Contract Quantity: See Special Conditions Below

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

Special Conditions:

A. Definitions

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

"Credit Support Provider" means___________________________.

"CFTC" means the Commodity Futures Trading Commission.

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

"FERC" means the Federal Energy Regulatory Commission.

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

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

“S&P” means S&P Global Ratings, or its successor.

B. Gas Service and Capacity Release

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

- **b. Daily Call:** On any day during the period of **November 1, 2019 through April 15, 2020**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point.

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

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

D. Nominations

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

E. Asset Management Fee

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

F. Credit Provisions

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

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

Exposure. shall be calculated as the sum of:

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

G. Asset Management Arrangement

The Parties agree that the transactions hereunder constitute an Asset Management Arrangement, as defined by FERC in Order

No. 712 (as modified and clarified) and in accordance with FERC's rules and regulations, and that Seller is acting as Asset Manager as defined in 18 CFR 284.8(h)(3).

H. Changes in Law

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

Seller: By: ___________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company d/b/a National Grid By:_________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Attachment EDA/SAJ-11

Attachment EDA/SAJ-11

Tennessee FT-A Dracut to Cranston

Service Package No: 349449-FTATGP
Amendment No: 0.

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-A Rate Schedule)

THIS AGREEMENT is made and entered into as of the 1 day of November, 2019, by and between TENNESSEE GAS PIPELINE COMPANY, L.L.C., a Delaware limited liability company, hereinafter referred to as "Transporter" and THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID, a RHODE ISLAND CORPORATION, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

NOW THEREFORE, Transporter and Shipper agree as follows:

ARTICLE I

DEFINITIONS

1.1 TRANSPORTATION QUANTITY - shall mean the maximum daily quantity of gas which Transporter agrees to receive and Transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during the term hereof, as specified on Exhibit "A" attached hereto. Any limitations on the quantities to be received from each Point of Receipt and/or delivered to each Point of Delivery shall be as specified on Exhibit "A" attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

1.3 COMMENCEMENT DATE – shall mean November 1, 2019.

ARTICLE II

TRANSPORTATION

Commencing upon the Commencement Date, Transporter agrees to accept and receive daily on a firm basis in accordance with Rate Schedule FT-A, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III

POINT(S) OF RECEIPT AND DELIVERY

The Primary Point(s) of Receipt and Delivery shall be those points specified on Exhibit "A" attached hereto.

ARTICLE IV

FACILITIES

All facilities are in place to render the service provided for in this Agreement and Transporter shall have no obligation to build facilities to perform this service.

ARTICLE V

QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the Parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter or a downstream pipeline, then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI

RATES AND CHARGES

6.1 TRANSPORTATION RATES - Commencing upon the Commencement Date, the rates, charges, and surcharges to be paid by Shipper to Transporter for the transportation service provided herein shall be in accordance with Transporter's Rate Schedule FT-A and the General Terms and Conditions of Transporter's FERC Gas Tariff.

Except as provided to the contrary in any written or electronic agreement(s) between Transporter and Shipper in effect during the term of this Agreement, Shipper shall pay Transporter the applicable maximum rate(s) and all other applicable charges and surcharges specified in the Summary of Rates and Charges in Transporter's FERC Gas Tariff and in Rate Schedule FT-A. Transporter and Shipper may mutually agree from time to time to discounted rates or Negotiated Rates for service provided hereunder in accordance with the provisions of Rate Schedule FT-A and the General Terms and Conditions of Transporter's FERC Gas Tariff.

Transporter and Shipper may agree that a specific discounted rate will apply only to certain volumes under the agreement. Transporter and Shipper may agree that a specified discounted rate will apply only to specified volumes (MDQ, TQ, commodity volumes, Extended Receipt and Delivery Service Volumes or Authorized Overrun volumes) under the Agreement; that a specified discounted rate will apply only if specified volumes are achieved (with the maximum rates applicable to volumes above the specified volumes or to all volumes if the specified volumes are never achieved); that a specified discounted rate will apply only during specified periods of the year or over a specifically defined period of time; that a specified discounted rate will apply only to specified points, zones, markets or other defined geographical area; and/or that a specified discounted rate will apply only to production or reserves committed or dedicated to Transporter. Transporter and Shipper may agree to a specified discounted rate pursuant to the provisions of this Section 6.1 provided that the discounted rate is between the applicable maximum and minimum rates for this service.

In addition, a discount agreement may include a provision that if one rate component which was at or below the applicable Maximum Rate at the time the discount agreement was executed subsequently exceeds the applicable Maximum Rate due to a change in Transporter's Maximum Rates so that such rate component must be adjusted downward to equal the new applicable Maximum Rate, then other rate components may be adjusted upward to achieve the agreed overall rate, as long as none of the resulting rate components exceed the Maximum Rate applicable to that rate component. Such changes to rate components shall be applied prospectively, commencing with the date a Commission Order accepts revised tariff sheet rates. However, nothing contained herein shall be construed to

ARTICLE VI

RATES AND CHARGES (continued)

alter a refund obligation under applicable law for any period during which rates that had been charged under a discount agreement exceeded rates which ultimately are found to be just and reasonable.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid for by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-A or any successor rate schedule, (b) the rate schedule(s) pursuant to which service hereunder is rendered, and/or (c) any provision of the General Terms and Conditions of Transporter's FERC Gas Tariff applicable to those rate schedules or this Agreement. Transporter agrees that Shipper may protest or contest the aforementioned filings, and may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

6.4 [Not applicable.]

ARTICLE VII

BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles VII and VIII, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII

RATE SCHEDULE AND GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-A and to the General Terms and Conditions of Transporter's FERC Gas Tariff incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX

REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All Parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no Party shall be liable to any other Party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Subpart G, Part 284 of the FERC Regulations.

ARTICLE X

RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified, the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE XI

WARRANTIES

11.1 In addition to the warranties set forth in Article XI of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place by the Commencement Date, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit "A" attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) [Not applicable.]

(c) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

11.3 [Not applicable.]

ARTICLE XII

TERM

12.1 This Agreement shall be effective as of the date hereof. Service hereunder shall commence on the Commencement Date, and shall continue in effect until 31 October, 2020 ("Primary Term"), unless modified as per Exhibit "B". Any rights to Shipper's extension of this Agreement after the Primary Term shall be set forth in Exhibit "A" hereto; provided, however, if Exhibit "A" does not specify Shipper's extension rights under the Agreement, and if the Primary Term is one year or more, then any rights to Shipper's extension of this Agreement after the Primary Term shall be governed by Article V, Section 4 of the General Terms and Conditions of Transporter's FERC Gas Tariff; and provided further, that if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to resolve or cash out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff shall survive the other parts of this Agreement until such time as such balancing has been accomplished; provided, however, that Transporter notifies Shipper of such imbalance not later than twelve months after the termination of this Agreement.

12.3 This Agreement will terminate automatically upon written notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VIII of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE XIII

NOTICE

Except as otherwise provided in the General Terms and Conditions of Transporter's FERC Gas Tariff applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the address of the Party intended to receive the same, as follows:

TRANSPORTER: Tennessee Gas Pipeline Company, L.L.C.
1001 Louisiana Street, Suite 1000
Houston, Texas 77002

Attention: Director, Transportation Services

SHIPPER:

NOTICES: THE NARRAGANSETT ELECTRIC COMPANY D/B/A
NATIONAL GRID

100 EAST OLD COUNTRY ROAD
HICKSVILLE NY USA
11801

Attention: JOHN ALLOCCA

BILLING: THE NARRAGANSETT ELECTRIC COMPANY D/B/A
NATIONAL GRID

100 EAST OLD COUNTRY ROAD
HICKSVILLE NY USA
11801

Attention: JOHN ALLOCCA

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE XIV

ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Either Party may, without relieving itself of its obligation under this Agreement, assign any of its rights hereunder to a company with which it is affiliated. Otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article VI, Section 1 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

ARTICLE XV

MISCELLANEOUS

15.1 THE INTERPRETATION AND PERFORMANCE OF THIS CONTRACT SHALL BE IN ACCORDANCE WITH AND CONTROLLED BY THE LAWS OF THE STATE OF TEXAS, WITHOUT REGARD TO THE DOCTRINES GOVERNING CHOICE OF LAW.

15.2 If any provision of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either Party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's FERC Gas Tariff, no modification of or supplement to the terms and provisions stated in this Agreement shall be or become effective until Shipper has submitted a request for change through Transporter's Interactive Website and Shipper has been notified through Transporter's Interactive Website of Transporter's agreement to such change.

15.4 Exhibit "A" and, when applicable, Exhibit "B" attached hereto are incorporated herein by reference and made a part hereof for all purposes.

15.6 [Not applicable.]

15.7 [Not applicable.]

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed as of the date first hereinabove written.

Service Package No: 349449-FTATGP
Amendment No: 0.

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-A Rate Schedule)

TENNESSEE GAS PIPELINE COMPANY, L.L.C.

BY: ______________________
Agent and Attorney-in-Fact

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

BY: ______________________
Agent and Attorney-in-Fact

TITLE: ______________________

DATE: ______________________

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-A Rate Schedule)

EXHIBIT A
AMENDMENT NO. 0
TO GAS TRANSPORTATION AGREEMENT
DATED November 1, 2019
BETWEEN
TENNESSEE GAS PIPELINE COMPANY, L.L.C.
AND
THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

Amendment Effective Date: November 1, 2019

Service Package: 349449-FTATGP

Service Package TQ: 20000 Dth

BEGINNING DATE	ENDING DATE	TQ
11/01/2019	10/31/2020	20000

BEGINNING DATE	ENDING DATE	METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ
11/01/2019	10/31/2020	412538	MARITIME/TGP DRACUT MIDDLESEX	MARITIMES & N.E. P/L	MIDDLESEX	MA	6	R	200	20000
11/01/2019	10/31/2020	420750	NARNGST/TGP CRANSTON SALES PROVIDEN	NARRAGANSETT ELECTRIC	PROVIDENCE	RI	6	D	200	20000

Total Receipt TQ 20000

Total Delivery TQ 20000

Number of Receipt Points: 1

Number of Delivery Points: 1

Note: Exhibit A is a reflection of the contract and all amendments as of the amendment effective date.

DIRECT TESTIMONY

OF

MICHAEL J. PINI

AND

ANN E. LEARY

Table of Contents

I. Introduction

Michael J. Pini

Q. Please state your name and business address.

A. My name is Michael J. Pini and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am a Lead Program Manager in the New England Pricing department for National Grid USA Service Company, Inc. (Service Company). My responsibilities include the design, implementation, and administration of rates and tariffs for the gas division of The Narragansett Electric Company d/b/a National Grid (the Company) and its Massachusetts affiliates, Boston Gas Company (Boston Gas) and Colonial Gas Company (Colonial Gas), each d/b/a National Grid.

Q. Please provide your educational background.

A. I earned a Bachelor of Science in Economics and Finance from Bentley University in 2010.

Q. Please provide your professional background.

A. In 2009, I joined National Grid as an intern in the Support Services function within the Gas Operations department. In 2010, I became an Associate Analyst in the Regulatory

Compliance department. In 2011, I joined the New England Electric Pricing group and was promoted to Analyst in 2012. In 2013, my responsibilities changed to supporting Boston Gas and Colonial Gas and, in 2014, I was promoted to Senior Analyst in the same capacity. In 2017, I was promoted to Lead Program Manager, supporting the New England electric and gas operating companies.

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

A. I have testified before the PUC in support of the Company's FY 2020 Infrastructure, Safety and Reliability Plan filing in Docket No. 4916 and the Company's Excess Accumulated Deferred Income Tax True-Up filing in Docket No. 4770. Additionally, I have testified before the Massachusetts Department of Public Utilities (DPU) on several occasions related to the Gas System Enhancement Plans for Boston Gas and Colonial Gas, namely, to present the calculation of proposed Gas System Enhancement Plan Factors and associated bill impacts.

<u>Ann E. Leary</u>

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. By whom are you employed and in what capacity?

A. I am the Manager of New England Gas Pricing for the Service Company. In this position, I am responsible for preparing and submitting various regulatory filings with the PUC on behalf of the Company and with the DPU on behalf of Boston Gas and Colonial Gas.

Q. Please provide your educational background.

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

Q. Please provide your professional background.

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

A. Yes, I have testified before the PUC on numerous occasions, most recently in the Company's 2017 rate case in Docket No. 4770. I also submitted written testimony in the

Company's 2018 Distribution Adjustment Charge (DAC) filing in Docket No. 4846 and 2018 GCR filing in Docket No. 4872. In addition, I have testified extensively in several ratemaking and regulatory proceedings before the DPU and the New Hampshire Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to propose the Gas Cost Recovery (GCR) factors to become effective on November 1, 2019 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. Our testimony is comprised of the following three general sections: I. Introduction; II. GCR Factor Development; and III. Bill Impacts.

Q. Are you including any attachments with your testimony?

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

Attachment MJP/AEL-1	Gas Cost Recovery Factors **CONFIDENTIAL Information**

Attachment MJP/AEL-2	Annual GCR Reconciliation Filing **CONFIDENTIAL Information**
Attachment MJP/AEL-3	Projected Gas Cost Balances
Attachment MJP/AEL-4	Bill Impact Analysis
Attachment MJP/AEL-5	FT-2 Demand Rate **CONFIDENTIAL Information**
Attachment MJP/AEL-6	FT-2 Capacity Allocator Percentages
Attachment MJP/AEL-7	Marketer Reconciliation

II. GCR Factor 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, 2019 through October 31, 2020. As shown in the joint pre-filed direct testimony of Company witnesses Elizabeth D. Arangio and Samara A. Jaffe on Attachment EDA/SAJ-1, firm sales customers' gross gas costs for the 12 months ending October 31, 2020 are projected to be approximately $137.5 million. In addition to these projected costs, the GCR factors also include recovery of working capital costs, inventory financing costs, prior period reconciliations, impacts of hedging activities, and liquefied natural gas (LNG) operation and maintenance (O&M) costs, as well as credits for FT-2 Market Storage Demand and costs allocated to the DAC factors. The table below summarizes the costs and credits included in the proposed 2019-20 GCR factors:

GCR Component	Amount (millions)	Reference
Firm Gas Costs	$137.5	EDA/SAJ-1
Hedging Impact	$7.6	JMP-5
Working Capital Costs	$1.1	MJP/AEL-1, Page 2, Line (9) and Page 3, Line (6)
Inventory Financing Costs	$0.6	MJP/AEL-1, Page 3, Lines (9) and (10)
Prior Period Deferred Balance (Includes the Marketer Fixed Costs Reconciliation)	($1.5)	MJP/AEL-1, Page 2, Lines (10) and (11) and Page 3, Line (7)
LNG O&M Costs	$1.1	MJP/AEL-1, Page 2, Line (8) and Page 3, Line (8)
FT-2 Marketer Storage Demand Costs	($3.4)	MJP/AEL-1, Page 2, Line (4)
Commodity Costs Recovered via the DAC Factors Associated with System Pressure	($0.2)	MJP/AEL-1, Page 3, Line (2)
Total	$142.8	MJP/AEL-1, Page 2, Line (13) and MJP/AEL-1, Page 3, Line (12)

Thus, the proposed GCR factors are intended to recover approximately $142.8 million in net costs over the period November 1, 2019 through October 31, 2020.

Q. Briefly, 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 MJP/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. How was the fixed cost component of the proposed GCR factors developed?

A. The fixed cost component includes all fixed costs related to the purchase, storage, and delivery of firm gas for both High Load Factor and Low Load Factor customers. As shown in Attachment MJP/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 customers' share of credits earned through the operation of the Natural Gas Portfolio Management Plan (NGPMP), demand costs allocated to the DAC mechanism, if any, and storage demand costs billed to FT-2 Marketers. The FT-2 storage demand costs are calculated by multiplying the FT-2 Demand Charge rate by the forecast of storage and peaking maximum daily quantity (MDQ) to be billed to FT-2 Marketers. Adjustments are also made for supply-related LNG costs, working capital costs, and prior period deferred fixed gas costs under/over-recovery balances, 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 $61.1 million to be recovered over the period November 2019 through October 2020.

Finally, because the Company's gas supply resources are planned so that there is sufficient capacity to meet the needs of firm customers (excluding firm customers with capacity exempt status) under design winter conditions, the total fixed gas cost to be recovered from customers is allocated between High Load Factor and Low Load Factor customers. The allocation is based on the proportion of design winter use of these two groups of customers. The High Load and Low Load Factors for each group are derived using the allocated fixed gas cost to each group and dividing each amount by each group's projected throughput for the upcoming year. Accordingly, the proposed GCR fixed Low Load Factor is $2.2338 per dekatherm, while the proposed GCR fixed High Load Factor is $1.6788 per dekatherm, excluding the adjustment for uncollectible expense.

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

A. No. Like in last year's GCR filing in Docket No. 4872, the Company is not proposing to allocate any demand costs to the DAC for the DAC factors effective November 1, 2019. However as described later in the testimony, the Company is proposing to allocate LNG commodity costs associated with maintaining system pressure from the GCR to the DAC.

Q. How did the Company derive the 2019-20 throughput forecast used to calculate the High Load and Low Load GCR Factors?

A. The pre-filed direct testimony of Company witness Theodore E. Poe, Jr. supports the 2019-20 throughput forecast used to derive the proposed GCR factors.

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

A. In accordance with the Settlement Agreement approved in Docket No. 4199, the Company has included an annual reconciliation of Marketer fixed costs. The Company calculated the Marketer reconciliation by updating the 2018-19 pipeline surcharge/credit for each path that the Company filed last year and based the update on actual, instead of projected, pipeline capacity costs. The Company then compared the pipeline surcharge/credit approved in Docket No. 4872 for each path with the updated actual pipeline surcharge/credit. The Company then multiplied the difference by the Marketer's actual monthly capacity for the months of November 2018 through July 2019 and forecasted monthly capacity for the months of August 2019 through October 2019. This results in a surcharge to the Marketers of $4,444, as shown in Attachment MJP/AEL-7, Page 1, Line (22).

The Company also finalized the 2017-18 Marketer reconciliation that it filed last year in Docket No. 4872 to replace the Marketers' forecasted monthly capacity for the months of August 2018 through October 2018 with their actual monthly capacity. This update results in a Marketer credit of $19,158 associated with the latter portion of the 2017-18 period. In addition, the Company reconciled the actual revenue of $25,892 credited to Marketers during the period November 2018 through October 2019 with the actual 2017-18 Marketer credit of $19,158 and the prior period 2017-18 Marketer reconciliation credit balance of $6,537. This results in a net Marketer reconciliation surcharge of $197 for the 2017-18 period, as shown in Attachment MJP/AEL-7, Page 2, Line (48). The sum of the reconciliation amounts shown in Attachment MJP/AEL-7 for 2018-19 (Page 1, Line (22)) and 2017-18 (Page 2, Line (48)) is the total Marketer reconciliation amount of ($4,641), as shown on Page 2, Line (50) and reflected in Attachment MJP/AEL-1, Page 2, Line (12).

Attachment MJP/AEL-7 shows the calculation of the Marketer reconciliation adjustment for both the 2017-18 and 2018-19 periods. In addition to surcharging firm sales customers' fixed costs for this amount, the Company included the reconciliation in its calculation of the 2018-19 pipeline surcharge/credits, as detailed in the joint testimony of Ms. Arangio and Ms. Jaffe as shown in Attachment EDA/SAJ-1. The Company has provided additional detail for monthly capacity release information for each pipeline path in an Excel file contained in the USB flash drive provided to the Division with this filing.

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

A. As done last year in Docket No. 4872, the Company calculated the monthly design sales forecast by applying a monthly heat factor to the monthly design degree days. The monthly heat factor was computed by dividing the heating component of the normal sales (normal sales less monthly base use) by normal degree days for each month during the period November 2019 through March 2020. 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 MJP/AEL-1, Pages 14 through 16, the Company has provided detailed calculations showing the derivation of the monthly design sales.

Q. How was the variable cost component of the proposed GCR factors 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, and excludes variable costs allocated to the DAC mechanism, if any. As shown in Attachment MJP/AEL-1, Page 3, Line (12), the total estimated variable cost for the period November 2019 through October 2020 is $81.7 million. The variable costs are divided by the projected throughput to obtain a variable cost factor of $2.9671 per dekatherm.

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

A. Yes. For the factors effective November 1, 2019, the Company is proposing to allocate variable costs of $163,175 to the DAC. The Company has determined that it requires injection of 32,505 dekatherms per year from its Exeter LNG facility into the Company’s distribution system to maintain distribution system pressure in a normal winter. The

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Company multiplied these volumes by its average inventory price of $5.02 per dekatherm to determine the amount to be recovered through the DAC. The Company has therefore deducted $163,175 from the variable costs to be recovered through the GCR, as shown on Attachment MJP/AEL-1, Page 3, Line (2).

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 2019 and forecasted data for the months of August through October 2019, the total estimated deferred balance at October 31, 2019 is an over-recovery of approximately $1.5 million, as shown in Attachment MJP/AEL-1, Page 7. This deferred balance is incorporated into the development of the proposed GCR factors effective for the period November 1, 2019 to October 31, 2020. In addition, the Company shows the projected monthly deferred gas cost balances for November 2019 through October 2020 in Attachment MJP/AEL-3.

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

A. Yes. The Company is including in its GCR an estimate of third-party portable LNG equipment and services at the former Cumberland LNG tank location and at Old Mill

Lane on Aquidneck Island. These cost estimates are reflected the pre-filed testimony and Attachments of Company witnesses Elizabeth D. Arangio and Samara Jaffe.

Q. Attachment MJP/AEL-2 provides the fiscal year 2019 Annual GCR Reconciliation balances. Does the monthly information shown in Attachment MJP/AEL-2 correspond with the monthly deferred balance reports filed in Docket Nos. 4719 and 4872?

A. Yes. The March 31, 2019 reconciliation balance of $5,432,025 shown in Attachment MJP/AEL-2 reflects the balance that was submitted on June 28, 2019 in the annual GCR reconciliation report and is the same balance reflected in the July 2019 monthly deferred balance report filed in Docket No. 4872 on August 20, 2019.

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

A. Yes. Consistent with the modifications in Docket No. 4270, the Company is submitting for approval its FT-2 Marketer Demand rate of $12.4637 per MDQ in dekatherms per month, as shown in Attachment MJP/AEL-5, as well as the storage and peaking charge of $0.1076 per therm for FT-1 firm transportation customers returning to Transitional Sale Service (TSS). 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 MJP/AEL-6. The Company has also provided the detail calculations of the capacity assignment percentages in an Excel file contained in the USB flash drive provided to the Division with this filing.

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

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

The FT-2 Demand rate is derived by first totaling the fixed storage costs, associated inventory finance, working capital charges, and supply-related LNG O&M costs, less any demand credits assigned to the DAC factors and any refunds, if applicable. That total is then divided by the total storage and peaking MDQ for the year to derive a monthly per dekatherm rate to be charged to Marketers. As shown in Attachment MJP/AEL-5, the proposed FT-2 Marketer Demand rate is $12.4637 per dekatherm and will be applied to the Marketers’ storage and peaking MDQ.

III. Bill Impacts

Q. Is the Company presenting the impacts of its proposed rates for November 1, 2019 on customer bills in this filing?

A. Yes it is. The Company is presenting the bill impacts associated with its proposed GCR factors in this filing as well as its proposed DAC factors submitted in Docket No. 4955. The bill impacts are presented in Attachment MJP/AEL-4 and reflect current annual bills in Column (c) assuming that the rates in effect during September 2019 are effective for 12 months.

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

A. An average Residential Heating customer using 845 therms per year will experience a total annual bill of $1,202.81 based on the proposed GCR and DAC factors, which is a decrease of $147.58, or 10.9 percent, from last year's bills. This overall decrease is comprised of a decrease of $146.95 as a result of the proposed GCR factors; an increase of $3.80 as a result of the proposed DAC factors as revised in a supplemental filing on September 3, 2019 in Docket No. 4955; and a decrease of $4.43 in Gross Earnings Tax.

Q. Does this conclude your testimony?

A. Yes.

Attachments of Michael J. Pini and Ann E. Leary

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

Attachment MJP/AEL-1
Gas Cost Recovery Factors

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2019

	Source				FT-2
Description (a)	Reference (b)	Line # (c)	High Load[1] (d)	Low Load[2] (e)	Mkter[3] (f)
(1) Fixed Cost Factor - $/dktherm	MJP/AEL-1, pg 2	Line (17)	$1.6788	$2.2338	
(2) Variable Cost Factor -$/dktherm	MJP/AEL-1, pg 3	Line (14)	$2.9671	$2.9671	
(3) Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$4.6459	$5.2009	
(4) Uncollectible %	Docket 4770		1.91%	1.91%	
(5) Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) ÷ [1 - (4)]		$4.7363	$5.3021	
(6) GCR Charge on a per therm basis	(5) ÷ 10		**$0.4736**	**$0.5302**	
(7) Current rate effective 09/01/19 - $/therm	Docket 4872		$0.6100	$0.7041	
(8) Increase / (Decrease) - $/therm	(6) - (7)		($0.1364)	($0.1739)	
(9) Percent Decrease	(8) ÷ (7)		-22.4%	-24.7%	

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

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

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

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

		Source			High Load	Low Load
	Description (a)	Reference (b)	Line # (c)	Amount (d)	Factor Total (e)	Factor Total (f)
(1)	Fixed Costs (net of Cap Rel to marketers)	MJP/AEL-1, pg 5	Line (42)	$75,510,312		
	Less:					
(2)	NGPMP Customer Benefit	EDA/SAJ-1		($5,700,000)		
(3)	Interruptible Costs			$0		
(4)	FT-2 Storage Demand Costs	MJP/AEL-5, pg 2	Line (25)	($3,390,750)		
(5)	System Pressure to DAC			$0		
(6)	Refunds			$0		
(7)	Total Credits	Sum[(2):(6)]		($9,090,750)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Dkt 4770	Compliance Attachment 2 Schedule 32 Pg 5	$829,823	$829,823	$69,152
(9)	Working Capital Requirement	MJP/AEL-1, pg 9	Line (16)	$572,574		
(10)	Deferred Fixed Cost Over-recovered	MJP/AEL-1, pg 7	Line (17)	($6,712,469)		
(11)	Reconciliation Amount from Fixed costs- Marketers	MJP/AEL-7, pg 2	Line (50)	($4,641)		
(12)	Total Additions	Sum[(8):(11)]		($5,314,713)		
(13)	Total Fixed Costs	(1) + (7) + (12)		$61,104,849		
(14)	Design Winter Sales Percentage	MJP/AEL-1, pg 13	Lines (10) & (11)		2.25%	97.75%
(15)	Allocated Supply Fixed Costs	(13) x (14)			$1,374,859	$59,729,990
(16)	Sales (Dth) Nov 2019 - Oct 2020	MJP/AEL-1, pg 12	Line (9)	27,557,060	818,916	26,738,144
(17)	Fixed Factor	(15) ÷ (16)			**$1.6788**	**$2.2338**

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

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

		Source		
	Description	Reference	Line #	Amount
	(a)	(b)	(c)	(d)
(1)	Variable Costs, excluding Refunds	MJP/AEL-1, pg 6	Line (74) - Line (71)	$75,230,022
	Less:			
(2)	System Pressure to DAC			($163,175)
(3)	Non-Firm Sales			$0
(4)	Refunds	MJP/AEL-1, pg 6	Line (71)	$0
(5)	Total Credits	Sum [(2):(4)]		($163,175)
	Plus:			
(6)	Working Capital	MJP/AEL-1, pg 9	Line (32)	$569,212
(7)	Deferred Variable Cost Under-recovered	MJP/AEL-1, pg 7	Line (35)	$5,231,873
(8)	Supply Related LNG O&M	Docket 4770	Compliance Attachment 2 Schedule 32 Pg 5 Ln 15 - Ln 12	$302,244
(9)	Inventory Financing - LNG	MJP/AEL-1, pg 11	Line (22)	$159,192
(10)	Inventory Financing - Storage	MJP/AEL-1, pg 11	Line (12)	$436,278
(11)	Total Additions	Sum [(6):(10)]		$6,698,799
(12)	Total Variable Supply Costs	(1) + (5) + (11)		$81,765,646
(13)	Sales (Dth) Nov 2019 - Oct 2020	MJP/AEL-1, pg 12	Line (9)	27,557,060
(14)	Variable Cost Factor	(12) ÷ (13)		**$2.9671**

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

	Description (a)	Reference (b)	Nov-19 (c)	Dec-19 (d)	Jan-20 (e)	Feb-20 (f)	Mar-20 (g)	Apr-20 (h)	May-20 (i)	Jun-20 (j)	Jul-20 (k)	Aug-20 (l)	Sep-20 (m)	Oct-20 (n)	Nov-Oct (o)
	Supply Fixed Costs - Pipeline Delivery														
(1)	Dawn to E.Here	EDA/SAJ-1	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$1,159,055	$13,908,656
(2)	Dawn to WADDY	EDA/SAJ-1	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$23,870	$286,443
(3)	Dominion SP	EDA/SAJ-1	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$8,274	$99,293
(4)	Dracut	EDA/SAJ-1	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$92,862	$1,114,344
(5)	Everett	EDA/SAJ-1	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$116,077	$1,392,930
(6)	Manchester Lateral	EDA/SAJ-1	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$3,153,600
(7)	Millennium/AIM	EDA/SAJ-1	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$924,176	$11,090,109
(8)	Niagara	EDA/SAJ-1	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$7,474	$89,692
(9)	TCO App	EDA/SAJ-1	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$253,950	$3,047,400
(10)	TCO App/M3/Storage	EDA/SAJ-1	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$355,215	$4,262,583
(11)	TCO M3	EDA/SAJ-1	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$47,099	$565,191
(12)	Tetco M2	EDA/SAJ-1	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$774,571	$9,294,852
(13)	TetcoM2/M3	EDA/SAJ-1	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$368,340	$4,420,086
(14)	Transco Leidy	EDA/SAJ-1	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$9,681	$116,173
(15)	Yankee Interconnect	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(16)	Zone 4	EDA/SAJ-1	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$616,305	$7,395,658
(17)	Zone 4 CXN	EDA/SAJ-1	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$3,167,259
(18)	AMA Credits	EDA/SAJ-1	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($156,828)	($1,881,937)
(19)	Less Credits from Mkter Releases	EDA/SAJ-1	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($961,210)	($11,534,524)
(20)	Total Supply Fixed Costs - Pipeline	Sum[(1):(19)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Supply Fixed - Supplier														
(21)	Distrigas FCS	EDA/SAJ-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Total	(21)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23)	Total Supply Fixed (Pipeline & Supplier)	(20) + (22)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Storaged Fixed Costs - Facilities														
(24)	Columbia FSS	EDA/SAJ-1	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$116,328
(25)	Dominion GSS	EDA/SAJ-1	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$35,242	$422,906
(26)	Dominion GSSTE	EDA/SAJ-1	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$43,811	$525,733
(27)	Providence LNG	EDA/SAJ-1	$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
(28)	Tennessee FSMA	EDA/SAJ-1	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$567,325
(29)	Tetco FSS1	EDA/SAJ-1	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$1,456	$17,473
(30)	Tetco SS1	EDA/SAJ-1	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$94,328	$1,131,938
(31)	Total Fixed Storage Costs	Sum[(24):(30)]	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$4,746,584

REDACTED

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

Description (a)	Reference (b)	Nov-19 (c)	Dec-19 (d)	Jan-20 (e)	Feb-20 (f)	Mar-20 (g)	Apr-20 (h)	May-20 (i)	Jun-20 (j)	Jul-20 (k)	Aug-20 (l)	Sep-20 (m)	Oct-20 (n)	Nov-Oct (o)
Storage Fixed Costs - Delivery														
(32) Storage Delivery	EDA/SAJ-1	$403,440	$403,440	$403,440	$403,440	$403,440	$377,990	$377,990	$377,990	$377,990	$377,990	$377,990	$377,990	$4,663,124
(33) LNG	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(34) Proposed CNG/LNG	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(35) Everett Supply Deal	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(36) Algonquin Citygate Peaking	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(37) Proposed Everett Supply Deal	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(38) Proposed Summer Trucking	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(39) Proposed Winter Trucking	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(40) Storage Delivery Fixed Cost	Sum[(32):(39)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(41) Total Storage Fixed	(31) + (40)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(42) Total Fixed Costs	(23)+(31)+(40)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$75,510,312

REDACTED

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

Description	Reference	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Variable Commodity Costs														
(43) AGT Citygate	EDA/SAJ-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(44) AIM at Ramapo	EDA/SAJ-1	$31,955	$18,233	$0	$0	$0	$9,188	$0	$0	$0	$0	$0	$29,405	$88,780
(45) Const Summer Refill	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(46) Const Winter Refill	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(47) Dawn via IGTS	EDA/SAJ-1	$0	$10,729	$28,550	$8,401	$687	$0	$0	$0	$0	$0	$0	$0	$48,367
(48) Dawn via PNGTS	EDA/SAJ-1	$104,525	$772,173	$1,511,834	$1,457,062	$672,205	$19,401	$0	$197,855	$161,991	$0	$0	$0	$4,897,045
(49) Dominion SP	EDA/SAJ-1	$30,177	$35,539	$39,168	$36,308	$37,555	$7,867	$0	$0	$0	$0	$0	$0	$186,615
(50) Everett Long-Term	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(51) Everett Swing	EDA/SAJ-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(52) Millennium	EDA/SAJ-1	$516,939	$574,908	$648,595	$601,227	$621,887	$558,294	$388,630	$117,038	$0	$7,371	$2,099	$532,484	$4,569,472
(53) Niagara	EDA/SAJ-1	$62,954	$77,942	$81,716	$76,225	$79,311	$0	$0	$0	$0	$0	$0	$0	$378,148
(54) TCO Appalachia	EDA/SAJ-1	$1,557,710	$2,631,144	$2,787,413	$2,585,501	$2,657,601	$1,132,856	$106,414	$100,685	$0	$106,722	$65,705	$57,494	$13,789,245
(55) TCO M3	EDA/SAJ-1	$61,086	$67,694	$0	$0	$95,980	$28,837	$5,313	$0	$0	$0	$0	$79,656	$338,566
(56) Tetco M2	EDA/SAJ-1	$1,549,614	$1,930,536	$2,064,795	$1,938,365	$1,844,773	$1,664,973	$1,629,536	$1,574,723	$1,568,893	$1,586,527	$1,493,281	$837,809	$19,683,823
(57) Tetco M3	EDA/SAJ-1	$523,828	$25,029	$0	$0	$146,898	$244,091	$340,052	$0	$0	$0	$507,119	$1,828,631	$3,615,648
(58) TGP Z4	EDA/SAJ-1	$972,490	$1,561,570	$2,138,571	$1,935,895	$1,332,684	$707,463	$921,904	$558,736	$52,951	$431,266	$728,904	$1,017,313	$12,359,747
(59) Transco Leidy	EDA/SAJ-1	$70,376	$82,933	$89,550	$82,868	$83,939	$72,029	$57,990	$42,780	$37,602	$38,813	$42,441	$63,105	$764,426
(60) Waddington	EDA/SAJ-1	$0	$0	$0	$0	$0	$66,906	$0	$0	$0	$0	$0	$0	$66,906
(61) Total Variable Commodity Costs	Sum[(43):(60)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Storage Costs														
(62) Underground Storage	EDA/SAJ-1	$72,475	$1,642,603	$2,069,524	$1,893,567	$1,321,544	$114,441	$0	$0	$0	$0	$0	$0	$7,114,153
(63) LNG Withdrawals and Trucking	EDA/SAJ-1	$74,370	$83,678	$1,022,223	$587,490	$76,849	$68,602	$68,859	$66,539	$68,328	$68,310	$65,622	$67,304	$2,318,174
(64) Total Variable Storage Costs	(62) + (63)	$146,846	$1,726,281	$3,091,747	$2,481,057	$1,398,393	$183,042	$68,859	$66,539	$68,328	$68,310	$65,622	$67,304	$9,432,328
Variable Transportation Costs														
(65) Variable Costs for Purchases to City Gate	EDA/SAJ-1	$269,509	$342,792	$376,207	$354,589	$316,844	$213,949	$125,174	$82,639	$72,394	$81,191	$77,922	$118,009	$2,431,220
(66) Variable Cost for Storage Withdrawal	EDA/SAJ-1	$5,052	$99,359	$125,702	$113,998	$77,800	$7,883	$0	$0	$0	$0	$0	$0	$429,795
(67) Variable Cost for Storage Injection	EDA/SAJ-1	$0	$0	$0	$0	$0	$135,483	$157,117	$151,765	$21,866	$17,382	$171,989	$44,411	$700,013
(68) Total Variable Transportation Costs	Sum[(65):(67)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injections														
(69) Cost of Injections	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(70) Variable Cost for Storage Injection	EDA/SAJ-1	$0	$0	$0	$0	$0	($135,483)	($157,117)	($151,765)	($21,866)	($17,382)	($171,989)	($44,411)	($700,013)
(71) Refunds	EDA/SAJ-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(72) Total Injections	Sum[(69):(71)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted])
Hedging Impact														
(73) Hedging Impact	JMP-5	$1,108,957	$1,450,454	$1,476,544	$1,371,303	$978,734	$362,787	$256,280	$151,978	$109,978	$85,025	$98,606	$138,954	$7,589,602
(74) Total Variable Costs	(61)+(64)+(68)+(72) +(73)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$75,230,022
(75) Total Supply Costs	(42) + (74)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$150,740,334
Storage Costs for FT-2 Calculation														
(76) Storage Fixed Costs - Facilities	(31)	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$395,549	$4,746,584
(77) Storage Fixed Costs - Deliveries	(40)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(78) Total Storage Costs	(76) + (77)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4963
Attachment MJP/AEL-1
Redacted
Page 7 of 16

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

	Description	Nov-18 actual	Dec-18 actual	Jan-19 actual	Feb-19 actual	Mar-19 actual	Apr-19 actual	May-19 actual	Jun-19 actual	Jul-19 actual	Aug-19 forecast	Sep-19 forecast	Oct-19 forecast	Nov-Oct
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	I. Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	$6,650,788	$5,634,774	$3,714,630	($124,172)	($5,720,511)	($10,178,562)	($15,354,534)	($16,918,561)	($15,686,922)	($13,431,804)	($10,941,730)	($8,662,455)	$6,650,788
(4)	Supply Fixed Costs (net of cap rel)	$4,923,133	$10,047,853	$10,511,600	$10,521,157	$10,514,015	$4,743,933	$4,553,884	$4,848,986	$4,764,467	$4,853,778	$4,833,429	$4,853,778	$79,970,014
(5)	Reservation Charge _ Crary Street	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6)	Supply Related LNG O&M	$69,152	$69,152	$69,152	$69,152	$223,335	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$984,006
(7)	NGPMP Credits	($333,333)	($333,333)	($273,380)	($333,333)	($1,094,057)	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($4,700,770)
(8)	Working Capital	$37,331	$76,190	$79,707	$79,779	$79,725	$35,972	$34,531	$36,769	$36,128	$36,805	$36,651	$36,805	$606,391
(9)	Total Supply Fixed Costs	$4,696,283	$9,859,862	$10,387,079	$10,336,755	$9,723,018	$4,515,723	$4,324,233	$4,621,573	$4,536,414	$4,626,402	$4,605,898	$4,626,402	$76,859,641
(10)	Supply Fixed - Revenue	$5,753,304	$11,793,274	$14,231,210	$15,925,259	$14,157,473	$9,655,022	$5,840,364	$3,343,103	$2,238,081	$2,100,155	$2,298,466	$2,653,598	$89,989,309
(11)	Monthly Under/(Over) Recovery	($1,057,022)	($1,933,412)	($3,844,131)	($5,588,504)	($4,434,455)	($5,139,299)	($1,516,131)	$1,278,470	$2,298,333	$2,526,247	$2,307,432	$1,972,804	($13,129,667)
(12)	Prelim. Ending Under/(Over) Recovery	$5,593,766	$3,701,361	($129,500)	($5,712,676)	($10,154,966)	($15,317,861)	($16,870,665)	($15,640,091)	($13,388,589)	($10,905,557)	($8,634,298)	($6,689,651)	($6,478,880)
(13)	Month's Average Balance	$6,122,277	$4,668,068	$1,792,565	($2,918,424)	($7,937,739)	($12,748,211)	($16,112,599)	($16,279,326)	($14,537,756)	($12,168,681)	($9,788,014)	($7,676,053)	
(14)	Interest Rate (BOA Prime minus 200 bps)	3.25%	3.35%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
(15)	Interest Applied	$16,354	$13,269	$5,329	($7,836)	($23,596)	($36,673)	($47,896)	($46,831)	($43,215)	($36,173)	($28,157)	($22,818)	($258,243)
(16)	Marketer Reconcilation	$24,654	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,654
(17)	Fixed Ending Under/(Over) Recovery	$5,634,774	$3,714,630	($124,172)	($5,720,511)	($10,178,562)	($15,354,534)	($16,918,561)	($15,686,922)	($13,431,804)	($10,941,730)	($8,662,455)	($6,712,469)	($6,712,469)
(18)	II. Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$20,784,017	$24,523,145	$23,595,737	$25,064,563	$20,582,902	$15,610,587	$9,875,091	$6,657,384	$5,364,603	$5,145,112	$4,577,421	$4,192,628	$20,784,017
(20)														
(21)	Variable Supply Costs	$12,431,758	$13,230,810	$18,730,672	$14,225,717	$11,778,191	$5,203,973	$3,500,697	$2,291,416	$1,964,297	$1,509,839	$1,928,546	$3,772,209	$90,568,124
(22)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23)	Supply Related LNG O&M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(24)	Inventory Financing - LNG	$26,024	$27,743	$23,261	$24,764	$26,386	$25,905	$26,524	$26,234	$25,872	$17,765	$22,488	$22,492	$295,458
(25)	Inventory Financing - UG	$75,812	$71,250	$56,594	$44,527	$38,959	$41,121	$46,491	$51,042	$58,392	$53,365	$63,001	$72,733	$673,286
(26)	Working Capital	$94,267	$100,326	$142,030	$107,870	$89,311	$39,460	$26,545	$17,375	$14,895	$11,449	$14,624	$28,604	$686,754
(27)	Total Supply Variable Costs	$12,653,047	$13,455,316	$18,977,744	$14,428,064	$11,958,034	$5,335,646	$3,625,444	$2,411,253	$2,088,642	$1,617,606	$2,053,845	$3,921,225	$92,525,866
(28)	Supply Variable - Revenue	$8,992,116	$14,451,015	$17,581,135	$18,970,922	$16,984,064	$11,107,747	$6,867,686	$3,721,301	$2,323,731	$2,199,726	$2,451,234	$2,895,967	$108,546,645
(29)	Monthly Under/(Over) Recovery	$3,660,930	($995,699)	$1,396,609	($4,542,858)	($5,026,030)	($5,772,102)	($3,242,242)	($1,310,048)	($235,089)	($582,120)	($397,389)	$1,025,258	($16,020,779)
(30)	Prelim. Ending Under/(Over) Recovery	$24,444,948	$23,527,446	$24,992,346	$20,521,704	$15,556,873	$9,838,486	$6,632,848	$5,347,336	$5,129,515	$4,562,992	$4,180,032	$5,217,886	$4,763,238
(31)	Month's Average Balance	$22,614,483	$24,025,296	$24,294,042	$22,793,133	$18,069,888	$12,724,537	$8,253,969	$6,002,360	$5,247,059	$4,854,052	$4,378,727	$4,705,257	
(32)	Interest Rate (BOA Prime minus 200 bps)	3.25%	3.35%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
(33)	Interest Applied	$60,409	$68,291	$72,217	$61,198	$53,715	$36,605	$24,536	$17,267	$15,597	$14,429	$12,596	$13,987	$450,846
(34)	Gas Procurement Incentive/(penalty)	$17,789	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,789
(35)	Variable Ending Under/(Over) Recovery	$24,523,145	$23,595,737	$25,064,563	$20,582,902	$15,610,587	$9,875,091	$6,657,384	$5,364,603	$5,145,112	$4,577,421	$4,192,628	$5,231,873	$5,231,873
(36)	GCR Deferred Summary													
(37)	Beginning Under/(Over) Recovery	$27,434,805	$30,157,919	$27,310,368	$24,940,391	$14,862,391	$5,432,025	($5,479,443)	($10,261,177)	($10,322,319)	($8,286,692)	($6,364,309)	($4,469,827)	$27,434,805
(38)	Gas Costs	$17,473,884	$23,373,002	$29,336,612	$24,841,213	$22,540,728	$10,042,244	$8,148,919	$7,234,741	$6,823,103	$6,457,957	$6,856,313	$8,720,327	$171,849,041
(39)	Inventory Finance	$101,836	$98,993	$79,855	$69,290	$65,345	$67,026	$73,016	$77,276	$84,264	$71,131	$85,489	$95,225	$968,744
(40)	Working Capital	$131,597	$176,516	$221,736	$187,649	$169,036	$75,432	$61,076	$54,144	$51,022	$48,254	$51,274	$65,409	$1,293,145
(41)	NGPMP Credits	($333,333)	($333,333)	($273,380)	($333,333)	($1,094,057)	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($4,700,770)
(42)	Total Costs	$17,373,984	$23,315,177	$29,364,823	$24,764,818	$21,681,052	$9,851,369	$7,949,677	$7,032,827	$6,625,056	$6,244,008	$6,659,743	$8,547,627	$169,410,161
(43)	Revenue	$14,745,421	$26,244,289	$31,812,345	$34,896,180	$31,141,537	$20,762,769	$12,708,051	$7,064,404	$4,561,811	$4,299,881	$4,749,700	$5,549,565	$198,535,954
(44)	Monthly Under/(Over) Recovery	$2,628,563	($2,929,111)	($2,447,522)	($10,131,362)	($9,460,484)	($10,911,400)	($4,758,373)	($31,578)	$2,063,244	$1,944,127	$1,910,043	$2,998,062	($29,125,793)
(45)	Prelim. Ending Under/(Over) Recovery	$30,063,368	$27,228,808	$24,862,846	$14,809,029	$5,401,907	($5,479,375)	($10,237,816)	($10,292,755)	($8,259,074)	($6,342,565)	($4,454,266)	($1,471,765)	($1,690,988)
(46)	Month's Average Balance	$28,749,086	$28,693,364	$26,086,607	$19,874,710	$10,132,149	($23,675)	($7,858,630)	($10,276,966)	($9,290,696)	($7,314,629)	($5,409,287)	($2,970,796)	
(47)	Interest Rate (BOA Prime minus 200 bps)	3.25%	3.35%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
(48)	Interest Applied	$76,763	$81,560	$77,545	$53,362	$30,119	($68)	($23,361)	($29,564)	($27,618)	($21,743)	($15,561)	($8,831)	$192,603
(49)	Gas Purchase Plan Incentives/(Penalties)	$17,789	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,789
(50)		$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0	
(51)	Ending Under/(Over) Recovery W/ Interest	$30,157,919	$27,310,368	$24,940,391	$14,862,391	$5,432,025	($5,479,443)	($10,261,177)	($10,322,319)	($8,286,692)	($6,364,309)	($4,469,827)	**($1,480,596)**	($1,480,596)

Source: Docket No.4872 filed on August 20, 2019.

REDACTED

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

	Description (a)	Nov-19 fcst (b)	Dec-19 fcst (c)	Jan-20 fcst (d)	Feb-20 fcst (e)	Mar-20 fcst (f)	Apr-20 fcst (g)	May-20 fcst (h)	Jun-20 fcst (i)	Jul-20 fcst (j)	Aug-20 fcst (k)	Sep-20 fcst (l)	Oct-20 fcst (m)	Total Nov-Oct (n)
(1)	I. Fixed Cost Revenue													
(2)	(a) Low Load dth	1,879,191	3,371,151	4,528,392	5,157,998	3,949,896	3,102,160	1,268,369	831,696	635,775	607,000	624,963	781,553	26,738,144
(3)	Fixed Cost Factor	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	$2.2338	
(4)	Low Load Revenue	$4,197,737	$7,530,476	$10,115,523	$11,521,936	$8,823,277	$6,929,605	$2,833,283	$1,857,842	$1,420,195	$1,355,917	$1,396,043	$1,745,833	$59,727,667
(5)	(b) High Load dth	70,093	92,959	98,014	110,372	82,063	76,809	55,016	47,654	37,339	51,918	48,351	48,329	818,916
(6)	Fixed Cost Factor	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	$1.6788	
(7)	High Load Revenue	$117,673	$156,059	$164,546	$185,292	$137,768	$128,947	$92,361	$80,001	$62,685	$87,159	$81,171	$81,135	$1,374,797
(8)	sub-total Dth	1,949,284	3,464,109	4,626,406	5,268,370	4,031,959	3,178,969	1,323,385	879,349	673,115	658,918	673,314	829,882	27,557,060
(9)	FT-2 Storage Revenue from marketers	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$282,563	$3,390,750
(10)	Total Fixed Revenue	$4,597,973	$7,969,098	$10,562,632	$11,989,791	$9,243,608	$7,341,115	$3,208,207	$2,220,406	$1,765,443	$1,725,639	$1,759,777	$2,109,531	$64,493,214
(11)	II. Variable Cost Revenue													
(12)	(a) Firm Sales dth	1,949,284	3,464,109	4,626,406	5,268,370	4,031,959	3,178,969	1,323,385	879,349	673,115	658,918	673,314	829,882	27,557,060
(13)	Variable Cost Factor	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	$2.9671	
(14)	Variable Revenue	$5,783,722	$10,278,359	$13,727,010	$15,631,780	$11,963,225	$9,432,319	$3,926,615	$2,609,118	$1,997,199	$1,955,074	$1,997,790	$2,462,342	$81,764,553
(15)	Total Variable Revenue	$5,783,722	$10,278,359	$13,727,010	$15,631,780	$11,963,225	$9,432,319	$3,926,615	$2,609,118	$1,997,199	$1,955,074	$1,997,790	$2,462,342	$81,764,553
(16)	Total Gas Cost Revenue	$10,381,695	$18,247,457	$24,289,642	$27,621,571	$21,206,833	$16,773,434	$7,134,822	$4,829,524	$3,762,642	$3,680,713	$3,757,567	$4,571,873	$146,257,767

(2) MJP/AEL-1, pg 12, Sum [Lines (2)-(5), (7)]
(3) MJP/AEL-1, pg 1, Line 1, col (e)
(4) Line (2) x Line (3)
(5) MJP/AEL-1, pg 12, Sum [Lines (1), (6), (8)]
(6) MJP/AEL-1, pg 1, Line 1, col (d)
(7) Line (5) x Line (6)
(8) Line (2) + Line (5)
(9) [MJP/AEL-5, pg 2, Line (25)] ÷ 12
(10) Sum[Lines (4), (7), (9)]
(12) Line (8)
(13) MJP/AEL-1, pg 1, Line (2)
(14) Line (12) x Line (13)
(15) Line (14)
(16) Line (10) + Line (15)

REDACTED

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

Description (a)	Nov-19 (b)	Dec-19 (c)	Jan-20 (d)	Feb-20 (e)	Mar-20 (f)	Apr-20 (g)	May-20 (h)	Jun-20 (i)	Jul-20 (j)	Aug-20 (k)	Sep-20 (l)	Oct-20 (m)	Total (n)
(1) Fixed Costs	$5,314,218	$7,777,234	$7,775,900	$7,775,900	$7,775,900	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$75,510,312
(2) Capacity Release Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(3) Less System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4) Less: Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6) Allowable Working Capital Costs	$5,314,218	$7,777,234	$7,775,900	$7,775,900	$7,775,900	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$75,510,312
(7) Number of Days Lag	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
(8) Working Capital Requirement	$479,299	$701,443	$701,322	$701,322	$701,322	$503,672	$503,672	$503,672	$503,672	$503,672	$503,672	$503,672	
(9) Weighted Average Cost of Capital	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(10) Return on Working Capital Requirement	$34,270	$50,153	$50,145	$50,145	$50,145	$36,013	$36,013	$36,013	$36,013	$36,013	$36,013	$36,013	
(11) Cost of Debt (Long Term Debt + Short Term Debt)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(12) Interest Expense	$11,599	$16,975	$16,972	$16,972	$16,972	$12,189	$12,189	$12,189	$12,189	$12,189	$12,189	$12,189	
(13) Taxable Income	$22,671	$33,178	$33,173	$33,173	$33,173	$23,824	$23,824	$23,824	$23,824	$23,824	$23,824	$23,824	
(14) 1 - Combined Tax Rate	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
(15) Return and Tax Requirement	$28,697	$41,998	$41,991	$41,991	$41,991	$30,157	$30,157	$30,157	$30,157	$30,157	$30,157	$30,157	
(16) Fixed Working Capital Requirement	$40,296	$58,973	$58,963	$58,963	$58,963	$42,345	$42,345	$42,345	$42,345	$42,345	$42,345	$42,345	$572,574
(17) Variable Costs	$7,012,019	$11,625,621	$15,146,894	$13,510,947	$10,405,363	$5,117,929	$2,673,970	$1,713,896	$1,476,655	$1,502,496	$1,669,857	$3,374,375	$75,230,022
(18) Less: Non-firm Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19) Less: Supply Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20) Less: Bal. Related Syst. Pressure Commodity to DAC	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($163,175)
(21) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22) Allowable Working Capital Costs	$6,998,421	$11,612,023	$15,133,296	$13,497,349	$10,391,765	$5,104,331	$2,660,373	$1,700,298	$1,463,057	$1,488,899	$1,656,259	$3,360,777	$75,066,847
(23) Number of Days Lag	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
(24) Working Capital Requirement	$631,200	$1,047,309	$1,364,899	$1,217,350	$937,252	$460,369	$239,944	$153,353	$131,956	$134,286	$149,381	$303,114	
(25) Weighted Average Cost of Capital	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(26) Return on Working Capital Requirement	$45,131	$74,883	$97,590	$87,041	$67,014	$32,916	$17,156	$10,965	$9,435	$9,601	$10,681	$21,673	
(27) Cost of Debt (Long Term Debt + Short Term Debt)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(28) Interest Expense	$15,275	$25,345	$33,031	$29,460	$22,681	$11,141	$5,807	$3,711	$3,193	$3,250	$3,615	$7,335	
(29) Taxable Income	$29,856	$49,538	$64,560	$57,581	$44,332	$21,775	$11,349	$7,254	$6,242	$6,352	$7,066	$14,337	
(30) 1 - Combined Tax Rate	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
(31) Return and Tax Requirement	$37,792	$62,706	$81,721	$72,887	$56,116	$27,564	$14,366	$9,182	$7,901	$8,040	$8,944	$18,148	
(32) Variable Working Capital Requirement	$53,067	$88,051	$114,752	$102,347	$78,798	$38,705	$20,173	$12,893	$11,094	$11,290	$12,559	$25,484	$569,212

(1) MJP/AEL-1, Pg 2, Line (1)

(6) Sum[Lines (1)-(5)]
(7) Dkt 4770
(8) [Line (6) x Line (7)] ÷ 365
(9) Dkt 4770
(10 Line (8) x Line (9)
(11) Dkt 4770
(12) Line (8) x Line (11)

(13) Line (10) - Line (12)
(14) Tax Law effective Jan. 1, 2018
(15) Line (13) ÷ Line (14)
(16) Line (12) + Line (17)
(17) MJP/AEL-1, Pg 6, Line (74)
(20) MJP/AEL-1, Pg 3, Line (2) ÷ 12
(22) Sum[Lines (17):(21)]
(23) Dkt 4770
(24) [Line (22) x Line (23)] ÷ 365

(25) Dkt 4770
(26) Line (24) x Line (25)
(27) Dkt 4770
(28) Line (24) x Line (27)
(29) Line (26) - Line (28)
(30) Tax Law effective Jan. 1, 2018
(31) Line (29) ÷ Line (30)
(32) Line (28) + Line (31)

REDACTED

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

Description (a)	Nov-19 (b)	Dec-19 (c)	Jan-20 (d)	Feb-20 (e)	Mar-20 (f)	Apr-20 (g)	May-20 (h)	Jun-20 (i)	Jul-20 (j)	Aug-20 (k)	Sep-20 (l)	Oct-20 (m)	Total (n)
(33) Storage Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(34) Less: System Pressure to DAC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(35) Less: Credits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(36) Plus: Supply Related LNG O&M Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(37) Allowable Working Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(38) Number of Days Lag	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
(39) Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(40) Weighted Average Cost of Capital	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(41) Return on Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(42) Cost of Debt (Long Term Debt + Short Term Debt)	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(43) Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(44) Taxable Income	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(45) 1 - Combined Tax Rate	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
(46) Return and Tax Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(47) Storage Fixed Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$189,358

(33) MJP/AEL-1, pg 6, Line (78)
(34) MJP/AEL-1, Pg 9, Line (3)
(37) Sum[Lines (33) - (36)]
(38) Dkt 4770
(39) [Line (37) x Line (38)] ÷ 365
(40) Dkt 4770
(41) Line (39) x Line (40)
(42) Dkt 4770
(43) Line (39) x Line (42)
(44) Line (41) - Line (43)
(45) Tax Law effective Jan. 1, 2018
(46) Line (44) ÷ Line (45)
(47) Line (43) + Line (46)

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

Description (a)	Source (b)	Nov-19 (c)	Dec-19 (d)	Jan-20 (e)	Feb-20 (f)	Mar-20 (g)	Apr-20 (h)	May-20 (i)	Jun-20 (j)	Jul-20 (k)	Aug-20 (l)	Sep-20 (m)	Oct-20 (n)	Total (o)
(1) **Storage Inventory Balance**	EDA/SAJ-1	$8,780,200	$7,137,597	$5,068,073	$3,174,506	$1,852,963	$1,903,642	$3,150,540	$4,349,381	$4,958,656	$5,878,767	$7,297,414	$8,719,288	
(2) Hedging		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(3) Subtotal	(1) + (2)	$8,780,200	$7,137,597	$5,068,073	$3,174,506	$1,852,963	$1,903,642	$3,150,540	$4,349,381	$4,958,656	$5,878,767	$7,297,414	$8,719,288	
(4) Weighted Average Cost of Capital	Dkt 4770	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(5) Return on Working Capital Requirement	(3) x (4)	$627,784	$510,338	$362,367	$226,977	$132,487	$136,110	$225,264	$310,981	$354,544	$420,332	$521,765	$623,429	$4,452,378
(6) Cost of Debt (LTD + STD)*	Dkt 4770	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(7) Interest Charges Financed	(3) x (6)	$212,481	$172,730	$122,647	$76,823	$44,842	$46,068	$76,243	$105,255	$119,999	$142,266	$176,597	$211,007	$1,506,959
(8) Taxable Income	(5) - (7)	$415,303	$337,608	$239,720	$150,154	$87,645	$90,042	$149,021	$205,726	$234,544	$278,066	$345,168	$412,422	
(9) 1 - Combined Tax Rate		0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
(10) Return and Tax Requirement	(8) ÷ (9)	$525,701	$427,352	$303,443	$190,069	$110,943	$113,978	$188,634	$260,412	$296,892	$351,982	$436,921	$522,054	$3,728,379
(11) Working Capital Requirement	(7) + (10)	$738,181	$600,082	$426,090	$266,892	$155,785	$160,046	$264,877	$365,667	$416,891	$494,248	$613,519	$733,060	$5,235,338
(12) Storage-Related Inventory Costs	(11) ÷ 12	$61,515	$50,007	$35,508	$22,241	$12,982	$13,337	$22,073	$30,472	$34,741	$41,187	$51,127	$61,088	$436,278
(13) **LNG Inventory Balance**	EDA/SAJ-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(14) Weighted Average Cost of Capital	Dkt 4770	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(15) Return on Working Capital Requirement	(13) x (14)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,624,615
(16) Cost of Debt (LTD + STD)*	Dkt 4770	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(17) Interest Charges Financed	(13) x (16)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$549,870
(18) Taxable Income	(15) - (17)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(19) 1 - Combined Tax Rate		0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
(20) Return and Tax Requirement	(18) ÷ (19)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,360,437
(21) Working Capital Requirement	(17) + (20)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,910,307
(22) LNG-Related Inventory Costs	(21) ÷ 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$159,192
(23) Total Inventory Financing Costs	(12) + (22)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$595,470

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

REDACTED

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

	Rate Class (a)	Nov-19 (b)	Dec-19 (c)	Jan-20 (d)	Feb-20 (e)	Mar-20 (f)	Apr-20 (g)	May-20 (h)	Jun-20 (i)	Jul-20 (j)	Aug-20 (k)	Sep-20 (l)	Oct-20 (m)	Nov-Oct (n)
	SALES													
(1)	Residential Non-Heating	29,709	41,870	51,275	55,492	46,290	38,776	23,141	16,991	13,192	12,870	12,955	17,210	359,772
(2)	Residential Heating	1,429,498	2,555,419	3,445,650	3,857,433	2,980,582	2,286,040	846,216	583,887	459,638	438,537	451,733	606,383	19,941,015
(3)	Small C&I	150,515	303,783	415,091	508,832	363,216	301,269	136,398	64,071	48,264	48,825	56,322	37,859	2,434,444
(4)	Medium C&I	246,678	414,830	536,992	637,527	488,599	413,450	228,915	162,229	115,537	110,138	107,676	120,301	3,582,873
(5)	Large LLF	45,288	83,252	113,721	135,353	104,200	89,884	49,429	18,536	11,625	9,142	8,578	13,780	682,788
(6)	Large HLF	26,846	37,834	37,885	46,700	32,419	34,344	26,344	24,435	18,533	18,154	20,698	21,670	345,863
(7)	Extra Large LLF	7,212	13,867	16,938	18,854	13,299	11,516	7,411	2,973	713	358	654	3,230	97,024
(8)	Extra Large HLF	13,539	13,255	8,853	8,180	3,354	3,690	5,531	6,227	5,614	20,893	14,698	9,449	113,282
(9)	**Total Sales**	1,949,284	3,464,109	4,626,406	5,268,370	4,031,959	3,178,969	1,323,385	879,349	673,115	658,918	673,314	829,882	27,557,060
	TRANSPORTATION													
(10)	FT- Small	11,165	20,435	27,341	33,421	24,996	21,463	10,183	5,699	3,703	2,894	(1,887)	8,462	167,876
(11)	FT- Medium	200,389	293,770	386,304	425,292	347,711	281,992	158,024	112,249	84,404	78,280	78,019	100,794	2,547,227
(12)	FT- Large LLF	198,250	291,248	384,294	388,167	345,816	268,076	123,480	61,740	41,262	34,289	36,648	81,812	2,255,082
(13)	FT- Large HLF	94,541	118,006	134,808	143,660	112,838	106,846	85,446	81,785	73,341	72,848	83,287	84,953	1,192,358
(14)	FT- Extra Large LLF	144,245	160,610	221,386	195,217	205,841	136,737	46,871	32,317	28,022	24,730	29,225	79,971	1,305,173
(15)	FT- Extra Large HLF	570,817	614,146	673,344	649,969	574,792	529,217	488,245	494,970	485,524	480,646	520,637	545,953	6,628,261
(16)	**Total FT Transportation**	1,219,406	1,498,215	1,827,477	1,835,726	1,611,995	1,344,331	912,249	788,760	716,257	693,688	745,928	901,945	14,095,977
	Total THROUGHPUT													
(17)	Residential Non-Heating	29,709	41,870	51,275	55,492	46,290	38,776	23,141	16,991	13,192	12,870	12,955	17,210	359,772
(18)	Residential Heating	1,429,498	2,555,419	3,445,650	3,857,433	2,980,582	2,286,040	846,216	583,887	459,638	438,537	451,733	606,383	19,941,015
(19)	Small C&I	161,680	324,218	442,432	542,252	388,212	322,732	146,582	69,771	51,967	51,719	54,435	46,321	2,602,320
(20)	Medium C&I	447,068	708,601	923,296	1,062,819	836,310	695,442	386,939	274,477	199,940	188,417	185,696	221,094	6,130,100
(21)	Large LLF	243,537	374,500	498,015	523,520	450,016	357,960	172,909	80,276	52,887	43,431	45,226	95,592	2,937,870
(22)	Large HLF	121,386	155,840	172,693	190,360	145,258	141,189	111,789	106,220	91,875	91,003	103,985	106,623	1,538,221
(23)	Extra Large LLF	151,456	174,476	238,324	214,071	219,140	148,254	54,282	35,290	28,734	25,089	29,879	83,202	1,402,197
(24)	Extra Large HLF	584,356	627,401	682,198	658,149	578,146	532,906	493,776	501,198	491,138	501,539	535,334	555,401	6,741,543
(25)	**Total Throughput**	3,168,691	4,962,324	6,453,883	7,104,096	5,643,954	4,523,300	2,235,634	1,668,110	1,389,371	1,352,605	1,419,243	1,731,827	41,653,037

Source: Attachement TEP-1

REDACTED

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

	Rate Class (a)	Reference	Line #	Nov-19 (b)	Dec-19 (c)	Jan-20 (d)	Feb-20 (e)	Mar-20 (f)	Total (g)	% (h)
	SALES (dth)									
(1)	Residential Non-Heating	MJP/AEL-1, pg 16	Line (70)	31,951	46,425	57,420	62,264	51,417	249,478	1.14%
(2)	Residential Heating	MJP/AEL-1, pg 16	Line (71)	1,560,116	2,888,535	3,927,661	4,395,515	3,371,301	16,143,128	73.92%
(3)	Small C&I	MJP/AEL-1, pg 16	Line (72)	163,783	343,760	473,659	581,028	411,407	1,973,637	9.04%
(4)	Medium C&I	MJP/AEL-1, pg 16	Line (74)	264,896	462,803	605,434	721,009	546,808	2,600,949	11.91%
(5)	Large LLF	MJP/AEL-1, pg 16	Line (76)	50,004	94,887	130,455	155,124	118,790	549,260	2.51%
(6)	Large HLF	MJP/AEL-1, pg 16	Line (78)	27,920	40,767	40,875	51,186	34,443	195,191	0.89%
(7)	Extra Large LLF	MJP/AEL-1, pg 16	Line (80)	8,090	15,973	19,574	21,725	15,266	80,628	0.37%
(8)	Extra Large HLF	MJP/AEL-1, pg 16	Line (82)	13,552	13,255	8,853	8,180	3,354	47,194	0.22%
(9)	Total Sales	Sum[(1):(8)]		2,120,311	3,906,405	5,263,931	5,996,031	4,552,786	21,839,464	100.00%
(24)	Total Throughput			3,395,461	5,503,589	7,237,365	7,974,601	6,273,156	30,384,172	100.00%
(10)	Low Load Factor	Sum[(2)-(5),(7)]		2,046,888	3,805,958	5,156,782	5,874,401	4,463,572	21,347,601	97.75%
(11)	High Load Factor	Sum[(1),(6),(8)]		73,423	100,447	107,148	121,630	89,214	491,863	2.25%

2019/2020 Design Day Send Out

(12)	Pipeline	190,434	Dktherm
(13)	Underground Storage	42,814	Dktherm
(14)	LNG	155,498	Dktherm
(15)	Total Projected 2019/2020 Design Day	388,746	Dktherm

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

REDACTED

Derivation of Monthly Design Sales

Normal Volumes (Dth)

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	29,709	41,870	51,275	55,492	46,290	38,776	23,141	16,991	13,192	12,870	12,955	17,210	359,772
(2)	Residential Heating	1,429,498	2,555,419	3,445,650	3,857,433	2,980,582	2,286,040	846,216	583,887	459,638	438,537	451,733	606,383	19,941,015
(3)	Small C&I	150,515	303,783	415,091	508,832	363,216	301,269	136,398	64,071	48,264	48,825	56,322	37,859	2,434,444
(4)	Small Transport	11,165	20,435	27,341	33,421	24,996	21,463	10,183	5,699	3,703	2,894	(1,887)	8,462	167,876
(5)	Medium C&I	246,678	414,830	536,992	637,527	488,599	413,450	228,915	162,229	115,537	110,138	107,676	120,301	3,582,873
(6)	Med Transport	200,389	293,770	386,304	425,292	347,711	281,992	158,024	112,249	84,404	78,280	78,019	100,794	2,547,227
(7)	Large Low Load	45,288	83,252	113,721	135,353	104,200	89,884	49,429	18,536	11,625	9,142	8,578	13,780	682,788
(8)	Large Low Load- Transport	198,250	291,248	384,294	388,167	345,816	268,076	123,480	61,740	41,262	34,289	36,648	81,812	2,255,082
(9)	Large High Load	26,846	37,834	37,885	46,700	32,419	34,344	26,344	24,435	18,533	18,154	20,698	21,670	345,863
(10)	Large High Load- Transport	94,541	118,006	134,808	143,660	112,838	106,846	85,446	81,785	73,341	72,848	83,287	84,953	1,192,358
(11)	XL Low Load	7,212	13,867	16,938	18,854	13,299	11,516	7,411	2,973	713	358	654	3,230	97,024
(12)	XL Low Load-Transport	144,245	160,610	221,386	195,217	205,841	136,737	46,871	32,317	28,022	24,730	29,225	79,971	1,305,173
(13)	XL High Load	13,539	13,255	8,853	8,180	3,354	3,690	5,531	6,227	5,614	20,893	14,698	9,449	113,282
(14)	XL High Load-Transport	570,817	614,146	673,344	649,969	574,792	529,217	488,245	494,970	485,524	480,646	520,637	545,953	6,628,261
(15)	**Total**	3,168,691	4,962,324	6,453,883	7,104,096	5,643,954	4,523,300	2,235,634	1,668,110	1,389,371	1,352,605	1,419,243	1,731,827	41,653,037
(16)	HLF	735,451	825,111	906,166	904,002	769,694	712,871	628,706	624,409	596,205	605,412	652,274	679,235	8,639,535
(17)	LLF	2,433,239	4,137,214	5,547,717	6,200,095	4,874,260	3,810,428	1,606,927	1,043,701	793,167	747,193	766,969	1,052,592	33,013,502

Baseload

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-Oct
		30	31	31	29	31	30	31	30	31	31	30	31	
(18)	Residential Non-Heating	12,723	13,147	13,147	12,299	13,147	12,723	13,147	12,723	13,147	12,870	12,723	13,147	154,943
(19)	Residential Heating	440,187	454,860	454,860	425,515	454,860	440,187	454,860	440,187	454,860	438,537	440,187	454,860	5,353,964
(20)	Small C&I	50,025	51,693	51,693	48,358	51,693	50,025	51,693	50,025	48,264	48,825	50,025	37,859	590,175
(21)	Small Transport	1,536	1,587	1,587	1,485	1,587	1,536	1,587	1,536	1,587	1,587	(1,887)	1,587	15,317
(22)	Medium C&I	108,701	112,325	112,325	105,078	112,325	108,701	112,325	108,701	112,325	110,138	107,676	112,325	1,322,943
(23)	Med Transport	78,490	81,106	81,106	75,874	81,106	78,490	81,106	78,490	81,106	78,280	78,019	81,106	954,281
(24)	Large Low Load	9,569	9,888	9,888	9,250	9,888	9,569	9,888	9,569	9,888	9,142	8,578	9,888	115,006
(25)	Large Low Load- Transport	36,587	37,806	37,806	35,367	37,806	36,587	37,806	36,587	37,806	34,289	36,587	37,806	442,842
(26)	Large High Load	18,713	19,337	19,337	18,089	19,337	18,713	19,337	18,713	18,533	18,154	18,713	19,337	226,311
(27)	Large High Load- Transport	74,829	77,323	77,323	72,335	77,323	74,829	77,323	74,829	73,341	72,848	74,829	77,323	904,458
(28)	XL Low Load	562	581	581	544	581	562	581	562	581	358	562	581	6,639
(29)	XL Low Load-Transport	26,732	27,623	27,623	25,841	27,623	26,732	27,623	26,732	27,623	24,730	26,732	27,623	323,234
(30)	XL High Load	13,436	13,255	8,853	8,180	3,354	3,690	5,531	6,227	5,614	13,884	13,436	9,449	104,909
(31)	XL High Load-Transport	484,828	500,989	500,989	468,667	500,989	484,828	488,245	484,828	485,524	480,646	484,828	500,989	5,866,353
(32)	Total	1,356,919	1,401,521	1,397,119	1,306,880	1,391,620	1,347,173	1,381,053	1,349,710	1,370,201	1,344,290	1,351,010	1,383,881	16,381,376
(33)	HLF	604,529	624,051	619,650	579,570	614,150	594,783	603,583	597,321	596,160	598,403	604,529	620,245	7,256,974
(34)	LLF	752,390	777,470	777,470	727,310	777,470	752,390	777,470	752,390	774,041	745,886	746,480	763,636	9,124,402

REDACTED

Derivation of Monthly Design Sales

Heat Volumes

	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(35) Residential Non-Heating	16,986	28,723	38,128	43,193	33,143	26,053	9,994	4,269	45	0	232	4,063	204,829
(36) Residential Heating	989,311	2,100,558	2,990,790	3,431,918	2,525,721	1,845,852	391,355	143,699	4,777	0	11,546	151,522	14,587,050
(37) Small C&I	100,490	252,090	363,399	460,474	311,523	251,244	84,706	14,046	0	0	6,297	0	1,844,269
(38) Small Transport	9,629	18,848	25,753	31,936	23,409	19,927	8,596	4,163	2,116	1,307	0	6,875	152,559
(39) Medium C&I	137,977	302,506	424,668	532,449	376,275	304,749	116,591	53,527	3,212	0	0	7,976	2,259,930
(40) Med Transport	121,899	212,664	305,197	349,418	266,605	203,502	76,917	33,759	3,297	0	0	19,687	1,592,946
(41) Large Low Load	35,719	73,364	103,833	126,103	94,312	80,315	39,541	8,967	1,737	0	0	3,892	567,782
(42) Large Low Load- Transport	161,663	253,442	346,488	352,800	308,009	231,489	85,674	25,153	3,456	0	61	44,006	1,812,240
(43) Large High Load	8,133	18,497	18,549	28,611	13,083	15,631	7,007	5,722	0	0	1,985	2,333	119,551
(44) Large High Load- Transport	19,711	40,682	57,484	71,325	35,515	32,016	8,122	6,956	0	0	8,457	7,630	287,900
(45) XL Low Load	6,649	13,285	16,357	18,310	12,717	10,954	6,830	2,411	131	0	91	2,649	90,385
(46) XL Low Load-Transport	117,513	132,987	193,763	169,376	178,219	110,006	19,248	5,586	399	0	2,493	52,349	981,939
(47) XL High Load	103	0	0	0	0	0	0	0	0	7,009	1,261	0	8,373
(48) XL High Load-Transport	85,989	113,157	172,355	181,302	73,803	44,388	0	10,142	0	0	35,808	44,963	761,908
(49) Total	1,811,771	3,560,804	5,056,764	5,797,216	4,252,334	3,176,127	854,581	318,399	19,171	8,316	68,233	347,946	25,271,661
(50) HLF	130,922	201,060	286,516	324,432	155,544	118,089	25,123	27,088	45	7,009	47,744	58,990	1,382,561
(51) LLF	1,680,849	3,359,744	4,770,247	5,472,784	4,096,791	3,058,038	829,458	291,311	19,126	1,307	20,488	288,956	23,889,100
(52) **Normal Billing DD**	**409**	**763**	**1030**	**1046**	**905**	**652**	**309**	**132**	**17**	**1**	**17**	**154**	**5435**

Heat Factors

	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(53) Residential Non-Heating	42	38	37	41	37	40	32	32	3	0	14	26	38
(54) Residential Heating	2,419	2,753	2,904	3,281	2,791	2,831	1,267	1,089	281	0	679	984	2,684
(55) Small C&I	246	330	353	440	344	385	274	106	0	0	370	0	339
(56) Small Transport	24	25	25	31	26	31	28	32	124	1,307	0	45	28
(57) Medium C&I	337	396	412	509	416	467	377	406	189	0	0	52	416
(58) Med Transport	298	279	296	334	295	312	249	256	194	0	0	128	293
(59) Large Low Load	87	96	101	121	104	123	128	68	102	0	0	25	104
(60) Large Low Load- Transport	395	332	336	337	340	355	277	191	203	0	4	286	333
(61) Large High Load	20	24	18	27	14	24	23	43	0	0	117	15	22
(62) Large High Load- Transport	48	53	56	68	39	49	26	53	0	0	497	50	53
(63) XL Low Load	16	17	16	18	14	17	22	18	8	0	5	17	17
(64) XL Low Load-Transport	287	174	188	162	197	169	62	42	23	0	147	340	181
(65) XL High Load	0	0	0	0	0	0	0	0	0	7,009	74	0	2
(66) XL High Load-Transport	210	148	167	173	82	68	0	77	0	0	2,106	292	140
(67) Total	4,430	4,667	4,909	5,542	4,699	4,871	2,766	2,412	1,128	8,316	4,014	2,259	4,650
(68) **NormalBilling DD**	**409**	**763**	**1030**	**1046**	**905**	**652**	**309**	**132**	**17**	**1**	**17**	**154**	**5435**
(69) **DesignBilling DD**	**463**	**884**	**1196**	**1210**	**1045**	**746**	**349**	**155**	**23**	**2**	**15**	**175**	**6263**

REDACTED

Derivation of Monthly Design Sales

Design Sales

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(70) Residential Non-Heating	31,951	46,425	57,420	62,264	51,417	42,532	24,434	17,735	13,147	12,870	12,927	17,764	390,889
(71) Residential Heating	1,560,116	2,888,535	3,927,661	4,395,515	3,371,301	2,552,159	896,877	608,925	454,860	438,537	450,375	627,045	22,171,907
(72) Small C&I	163,783	343,760	473,659	581,028	411,407	337,492	147,363	66,519	48,264	48,825	55,581	37,859	2,715,539
(73) Small Transport	12,436	23,424	31,491	38,428	28,618	24,336	11,296	6,425	1,587	1,587	(1,887)	9,400	187,141
(74) Medium C&I	264,896	462,803	605,434	721,009	546,808	457,387	244,008	171,555	112,325	110,138	107,676	121,388	3,925,425
(75) Med Transport	216,483	327,496	435,491	480,076	388,954	311,331	167,981	118,131	81,106	78,280	78,019	103,478	2,786,827
(76) Large Low Load	50,004	94,887	130,455	155,124	118,790	101,463	54,547	20,098	9,888	9,142	8,578	14,311	767,288
(77) Large Low Load- Transport	219,594	331,440	440,136	443,482	393,464	301,450	134,571	66,123	37,806	34,289	36,641	87,813	2,526,807
(78) Large High Load	27,920	40,767	40,875	51,186	34,443	36,597	27,251	25,432	18,533	18,154	20,465	21,988	363,611
(79) Large High Load- Transport	97,143	124,458	144,072	154,843	118,332	111,462	86,497	82,997	73,341	72,848	82,292	85,994	1,234,279
(80) XL Low Load	8,090	15,973	19,574	21,725	15,266	13,096	8,295	3,393	581	358	643	3,591	110,586
(81) XL Low Load-Transport	159,760	181,699	252,614	221,773	233,411	152,597	49,363	33,290	27,623	24,730	28,932	87,110	1,452,902
(82) XL High Load	13,552	13,255	8,853	8,180	3,354	3,690	5,531	6,227	5,614	13,884	14,549	9,449	106,138
(83) XL High Load-Transport	582,170	632,091	701,122	678,395	586,209	535,616	488,245	496,737	485,524	480,646	516,424	552,084	6,735,265
(84) Total	3,407,898	5,527,013	7,268,857	8,013,029	6,301,774	4,981,207	2,346,259	1,723,588	1,370,201	1,344,290	1,411,215	1,779,274	45,474,604
(85) HLF	752,737	856,996	952,343	954,868	793,756	729,896	631,959	629,129	596,160	598,403	646,657	687,279	8,830,182
(86) LLF	2,655,161	4,670,017	6,316,514	7,058,160	5,508,018	4,251,311	1,714,301	1,094,460	774,041	745,886	764,558	1,091,995	36,644,422

Source: Attachement TEP-1

Attachment MJP/AEL-2

REDACTED

Attachment MJP/AEL-2
Annual GCR Reconciliation Filing

REDACTED

Deferred Gas Cost Balances

	Description	Apr-18 Actual	May-18 Actual	Jun-18 Actual	Jul-18 Actual	Aug-18 Actual	Sep-18 Actual	Oct-18 Actual	Nov-18 Actual	Dec-18 Actual	Jan-19 Actual	Feb-19 Actual	Mar-19 Actual	Apr-Mar
(1)	# of Days in Month	30	31	30	31	31	30	31	30	31	31	28	31	365
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(2)	I. Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	($2,415,056)	($4,673,556)	($4,609,247)	($1,228,566)	$434,405	$2,177,160	$5,017,420	$6,650,788	$5,634,774	$3,714,630	($124,172)	($5,720,511)	($2,415,056)
(4)	Supply Fixed Costs (net of cap rel)	$4,640,632	$4,541,674	$3,851,320	$3,926,133	$3,848,623	$3,884,767	$4,069,636	$4,923,133	$10,047,853	$10,511,600	$10,521,157	$10,514,015	$75,280,544
(5)	System Pressure to DAC (Res. Chge - Crary St.)[1]	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	$0	$0	$0	$0	$0	($1,839,600)
(6)	Supply Related LNG O&M	$47,965	$47,965	$47,965	$47,965	$47,965	$71,771	$71,771	$69,152	$69,152	$69,152	$69,152	$223,335	$883,310
(7)	NGPMP Credits	($908,333)	($908,333)	$1,110,429	($908,333)	($908,333)	$102,206	($908,333)	($333,333)	($333,333)	($273,380)	($333,333)	($1,094,057)	($5,696,468)
(8)	Working Capital	$21,940	$21,444	$17,984	$18,359	$17,971	$27,464	$28,866	$37,331	$76,190	$79,707	$79,779	$79,725	$506,760
(9)	Total Supply Fixed Costs	$3,539,403	$3,439,950	$4,764,898	$2,821,323	$2,743,426	$3,823,408	$2,999,140	$4,696,283	$9,859,862	$10,387,079	$10,336,755	$9,723,018	$69,134,545
(10)	Supply Fixed - Revenue	$5,789,902	$3,364,813	$1,377,328	$1,157,343	$1,003,994	$992,096	$1,381,854	$5,753,304	$11,793,274	$14,231,210	$15,925,259	$14,157,473	$76,927,848
(11)	Monthly Under/(Over) Recovery	($2,250,498)	$75,137	$3,387,570	$1,663,981	$1,739,432	$2,831,313	$1,617,286	($1,057,022)	($1,933,412)	($3,844,131)	($5,588,504)	($4,434,455)	($7,793,302)
(12)	Prelim. Ending Under/(Over) Recovery	($4,665,554)	($4,598,419)	($1,221,676)	$435,415	$2,173,837	$5,008,472	$6,634,706	$5,593,766	$3,701,361	($129,500)	($5,712,676)	($10,154,966)	($10,208,358)
(13)	Month's Average Balance	($3,540,305)	($4,635,987)	($2,915,462)	($396,575)	$1,304,121	$3,592,816	$5,826,063	$6,122,277	$4,668,068	$1,792,565	($2,918,424)	($7,937,739)	
(14)	Interest Rate (BOA Prime minus 200 bps)	2.75%	2.75%	2.88%	3.00%	3.00%	3.03%	3.25%	3.25%	3.35%	3.50%	3.50%	3.50%	
(15)	Interest Applied	($8,002)	($10,828)	($6,889)	($1,010)	$3,323	$8,948	$16,082	$16,354	$13,269	$5,329	($7,836)	($23,596)	$5,142
(16)	Marketer Reconcilation	$0	$0	$0	$0	$0	$0	$0	$24,654	$0	$0	$0	$0	$24,654
(17)	Fixed Ending Under/(Over) Recovery	($4,673,556)	($4,609,247)	($1,228,566)	$434,405	$2,177,160	$5,017,420	$6,650,788	$5,634,774	$3,714,630	($124,172)	($5,720,511)	($10,178,562)	($10,178,562)
(18)	II. Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$45,495,738	$33,235,112	$24,690,633	$22,511,998	$21,005,899	$20,250,094	$19,729,199	$20,784,017	$24,523,145	$23,595,737	$25,064,563	$20,582,902	$45,495,738
(20)	Variable Supply Costs	$8,209,810	$2,665,186	$2,239,378	$2,106,295	$2,244,622	$2,533,927	$5,500,076	$12,431,758	$13,230,810	$18,730,672	$14,225,717	$11,778,191	$95,896,441
(21)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Supply Related LNG O & M	$47,725	$47,725	$47,725	$47,725	$47,725	$22,568	$22,568	$25,187	$25,187	$25,187	$25,187	$25,187	$409,694
(23)	Inventory Financing - LNG	$13,836	$19,669	$20,895	$22,650	$24,170	$24,969	$26,180	$26,024	$27,743	$23,261	$24,764	$26,386	$280,548
(24)	Inventory Financing - UG	$40,056	$47,856	$56,364	$61,568	$64,814	$71,299	$77,287	$75,812	$71,250	$56,594	$44,527	$38,959	$706,385
(25)	Working Capital	$41,144	$13,357	$11,223	$10,556	$11,249	$19,214	$41,706	$94,267	$100,326	$142,030	$107,870	$89,311	$682,251
(26)	Total Supply Variable Costs	$8,352,570	$2,793,793	$2,375,584	$2,248,793	$2,392,581	$2,671,977	$5,667,817	$12,653,047	$13,455,316	$18,977,744	$14,428,064	$11,958,034	$97,975,319
(27)	Supply Variable - Revenue	$20,702,072	$11,405,840	$4,609,923	$3,810,262	$3,200,878	$3,242,592	$4,668,835	$8,992,116	$14,451,015	$17,581,135	$18,970,922	$16,984,064	$128,619,655
(28)	Monthly Under/(Over) Recovery	($12,349,502)	($8,612,047)	($2,234,339)	($1,561,469)	($808,298)	($570,615)	$998,982	$3,660,930	($995,699)	$1,396,609	($4,542,858)	($5,026,030)	($30,644,336)
(29)	Prelim. Ending Under/(Over) Recovery	$33,146,236	$24,623,065	$22,456,294	$20,950,529	$20,197,602	$19,679,478	$20,728,181	$24,444,948	$23,527,446	$24,992,346	$20,521,704	$15,556,873	$14,851,402
(30)	Month's Average Balance	$39,320,987	$28,929,089	$23,573,463	$21,731,264	$20,601,751	$19,964,786	$20,228,690	$22,614,483	$24,025,296	$24,294,042	$22,793,133	$18,069,888	
(31)	Interest Rate (BOA Prime minus 200 bps)	2.75%	2.75%	2.88%	3.00%	3.00%	3.03%	3.25%	3.25%	3.35%	3.50%	3.50%	3.50%	
(32)	Interest Applied	$88,876	$67,567	$55,704	$55,370	$52,492	$49,721	$55,837	$60,409	$68,291	$72,217	$61,198	$53,715	$741,396
(33)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$17,789	$0	$0	$0	$0	$17,789
(34)	Variable Ending Under/(Over) Recovery	$33,235,112	$24,690,633	$22,511,998	$21,005,899	$20,250,094	$19,729,199	$20,784,017	$24,523,145	$23,595,737	$25,064,563	$20,582,902	$15,610,587	$15,610,587
(35)	**GCR Deferred Summary**													
(36)	Beginning Under/(Over) Recovery	$43,080,683	$28,561,556	$20,081,386	$21,283,433	$21,440,304	$22,427,254	$24,746,619	$27,434,805	$30,157,919	$27,310,368	$24,940,391	$14,862,391	$43,080,683
(37)	Gas Costs	$12,683,331	$7,039,750	$5,923,587	$5,865,317	$5,926,135	$6,250,233	$9,401,251	$17,473,884	$23,373,002	$29,336,612	$24,841,213	$22,540,728	$170,655,042
(38)	Inventory Finance	$53,892	$67,526	$77,259	$84,218	$88,985	$96,268	$103,467	$101,836	$98,993	$79,855	$69,290	$65,345	$986,934
(39)	Working Capital	$63,084	$34,801	$29,207	$28,915	$29,220	$46,678	$70,572	$131,597	$176,516	$221,736	$187,649	$169,036	$1,189,010
(40)	NGPMP Credits	($908,333)	($908,333)	$1,110,429	($908,333)	($908,333)	$102,206	($908,333)	($333,333)	($333,333)	($273,380)	($333,333)	($1,094,057)	($5,696,468)
(41)	Total Costs	$11,891,973	$6,233,743	$7,140,482	$5,070,117	$5,136,006	$6,495,385	$8,666,957	$17,373,984	$23,315,177	$29,364,823	$24,764,818	$21,681,052	$167,134,518
(42)	Revenue	$26,491,974	$14,770,652	$5,987,251	$4,967,605	$4,204,872	$4,234,688	$6,050,689	$14,745,421	$26,244,289	$31,812,345	$34,896,180	$31,141,537	$205,547,502
(43)	Monthly Under/(Over) Recovery	($14,600,000)	($8,536,910)	$1,153,232	$102,512	$931,134	$2,260,697	$2,616,268	$2,628,563	($2,929,111)	($2,447,522)	($10,131,362)	($9,460,484)	($38,412,985)
(44)	Prelim. Ending Under/(Over) Recovery	$28,480,682	$20,024,647	$21,234,618	$21,385,944	$22,371,439	$24,687,951	$27,362,887	$30,063,368	$27,228,808	$24,862,846	$14,809,029	$5,401,906	
(45)	Month's Average Balance	$35,780,682	$24,293,101	$20,658,002	$21,334,689	$21,905,871	$23,557,602	$26,054,753	$28,749,086	$28,693,363	$26,086,607	$19,874,710	$10,132,149	
(46)	Interest Rate (BOA Prime minus 200 bps)	2.75%	2.75%	2.88%	3.00%	3.00%	3.03%	3.25%	3.25%	3.35%	3.50%	3.50%	3.50%	
(47)	Interest Applied	$80,874	$56,739	$48,815	$54,360	$55,815	$58,668	$71,918	$76,763	$81,560	$77,545	$53,362	$30,119	$746,538
(48)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$17,789	$0	$0	$0	$0	$17,789
(49)	**Ending Under/(Over) Recovery W/ Interest**	$28,561,556	$20,081,386	$21,283,433	$21,440,304	$22,427,254	$24,746,619	$27,434,805	$30,157,919	$27,310,368	$24,940,391	$14,862,391	$5,432,025	$5,432,025

[1] For the period Apr. 2018 through Oct. 2018, Dkt 4719; and for the period Nov. 2018 through Mar. 2019, Dkt 4872.
Line (6): In March 2018 the Company included the actual O&M costs associated with the LNG Storage Units at Cumberland LNG facility.

(3) Dkt 4872, Sch. AEL-2, pg 1, line (17), col. (m)
(4) Sch. 2, line (42)
(5) Dkt 4719; Dkt 4872
(6) Dkt 4323; Dkt 4770
(8) Sch. 4, line (15)
(9) Sum[Lines (4) : (8)]
(10) Sch. 3, line (13)
(11) Line (9) - Line (10)
(12) Line (3) + Line (11)
(13) [Line (3) + Line (12)] ÷ 2
(15) ([Line (13) x Line (14)] ÷ 365) x Line (1)
(16) Dkt 4872
(17) Line (12) + Line (15) + Line (16)
(19) Dkt 4872, Sch. AEL-2, pg 1, line (34), col. (m)
(20) Sch. 2, line (94)
(21) Dkt 4719; Dkt 4846
(22) Dkt 4323; Dkt 4770
(23) Sch. 5, line (22)
(24) Sch. 5, line (12)
(25) Sch. 4, line (30)
(26) Sum[Lines (20) : (25)]
(27) Sch. 3, line (30)
(28) Line (26) - Line (27)
(29) Line (19) + Line (28)
(30) [Line (19) + Line (29)] ÷ 2
(32) ([Line (30) x Line (31)] ÷ 365) x Line (1)
(34) Line (29) + Line (32) + Line (33)
(36) Line (3) + Line (19)
(37) Sum[Lines (4):(6), (16), (20):(22)]
(38) Line (23) + Line (24)
(39) Line (8) + Line (25)
(40) Line (7)
(41) Sum[Lines (37) : (40)]
(42) Line (10) + Line (27)
(43) Line (41) - Line (42)
(44) Line (36) + Line (43)
(45) [[Line (36) + Line (44)] ÷
(47) Line (15) + Line (32)
(48) Line (33)
(49) Line (44) + Line (47) + Lin

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Supply Estimates Actuals for Filing

	Description	Apr-18 Actual (a)	May-18 Actual (b)	Jun-18 Actual (c)	Jul-18 Actual (d)	Aug-18 Actual (e)	Sep-18 Actual (f)	Oct-18 Actual (g)	Nov-18 Actual (h)	Dec-18 Actual (i)	Jan-19 Actual (j)	Feb-19 Actual (k)	Mar-19 Actual (l)	Apr-Mar (m)
(1)	**SUPPLY FIXED COSTS - Pipeline Delivery**													
(2)	Algonquin (East to West, Hubline, AMA credits, Crary Street)	$1,686,724	$1,686,476	$1,597,162	$1,675,059	$1,684,411	$1,686,310	$1,681,291	$1,696,807	$1,674,252	$1,690,450	$1,641,927	$1,635,945	$20,036,815
(3)	TETCO/Texas Eastern	$714,507	$714,507	$714,507	$714,507	$717,189	$717,189	$717,189	$717,174	$717,275	$717,276	$724,008	$724,007	$8,609,336
(4)	Tennessee	$1,093,271	$1,136,569	$1,093,271	$1,093,271	$1,093,271	$1,093,271	$1,093,277	$894,722	$896,722	$894,722	$894,723	$894,723	$12,171,812
(5)	Tennessee Dracut / Demand Everett	$0	$0	$0	$0	$0	$0	$0	$250,728	$250,727	$250,727	$250,728	$250,085	$1,252,995
(6)	Portland Natural Gas Demand	$0	$0	$0	$0	$0	$0	$0	$279,513	$214,107	$250,100	$225,897	$251,804	$1,221,421
(7)	Iroquois	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$5,264	$5,667	$5,667	$5,667	$5,667	$5,667	$70,019
(8)	Union	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(9)	Transcanada to East Hereford Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(10)	Transcanada to Waddington Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(11)	Dominion	($28,532)	($28,532)	($28,532)	($34,537)	($28,532)	($28,532)	($28,532)	$2,241	$2,242	$2,242	$2,242	$2,241	($194,523)
(12)	Transco	$4,848	$5,010	$13,331	($3,473)	$5,010	$4,848	$5,010	$3,918	$5,010	$5,010	$4,525	$5,010	$58,054
(13)	Millenium Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$158,357	$158,357	$175,323	$492,037
(14)	National Fuel	$68	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$68
(15)	Columbia	$288,511	$288,551	$241,817	$290,061	$290,061	$290,061	$297,861	$549,829	$46,869	$302,929	$321,219	$320,907	$3,528,675
(16)	Alberta Northeast	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17)	Algonquin AFT (Crary Street)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	Westerly Lateral	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(19)	Less Credits from Mkter Releases	($749,190)	($1,021,216)	($1,021,700)	($1,076,285)	($1,192,115)	($1,178,415)	($989,932)	($747,435)	($754,500)	($753,985)	($697,080)	($740,845)	($10,922,699)
(20)	**Supply Fixed - Supplier**													
(21)	Distrigas FCS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	**Total**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23)	**STORAGE FIXED COSTS - Facilities**													
(24)	Texas Eastern	$84,942	$84,968	$84,864	$84,846	$85,046	$85,046	$85,074	$85,062	$84,887	$84,844	$85,685	$85,887	$1,021,152
(25)	Dominion	$83,088	$83,088	$83,088	$83,088	$83,088	$83,088	$83,088	$83,089	$83,089	$83,089	$83,091	$83,091	$997,068
(26)	Tennessee	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$47,277	$47,277	$47,277	$47,277	$47,277	$574,743
(27)	Columbia	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$116,328
(28)	National Grid LNG Tank Lease Payments	$0	$0	$0	$0	$0	$0	$0	$163,740	$163,740	$163,740	$163,740	$163,740	$818,700
(29)	**STORAGE FIXED COSTS - Delivery**													
(30)	Algonquin	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$2,585,230
(31)	TETCO	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,618	$87,618	$87,618	$87,618	$87,618	$1,051,323
(32)	Tennessee	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$86,425	$86,425	$86,425	$86,425	$86,425	$1,050,128
(33)	Dominion	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,827	$30,827	$30,827	$30,827	$30,827	$369,554
(34)	Columbia	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$15,593	$15,593	$15,593	$15,593	$15,593	$190,539
(35)	NG LNG Tank Lease Payments	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$0	$0	$0	$0	$0	$1,146,180
(36)	GAZ METRO LNG, LP/BCB LNG Fees: Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(37)	Distrigas FLS Call Payment/Engie Gas payment Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(38)	ENGIE Gas Demand Payment Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(39)	Texla	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(40)	Exelon	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(41)	Repsol Peaking Supply at Dracut	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(42)	**TOTAL FIXED COSTS**	$4,640,632	$4,541,674	$3,851,320	$3,926,133	$3,848,623	$3,884,767	$4,069,636	$4,923,133	$10,047,853	$10,511,600	$10,521,157	$10,514,015	$75,280,544

(42) Sum[Lines (2) : (41)]

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Supply Estimates Actuals for Filing

	Description	Apr-18 Actual (a)	May-18 Actual (b)	Jun-18 Actual (c)	Jul-18 Actual (d)	Aug-18 Actual (e)	Sep-18 Actual (f)	Oct-18 Actual (g)	Nov-18 Actual (h)	Dec-18 Actual (i)	Jan-19 Actual (j)	Feb-19 Actual (k)	Mar-19 Actual (l)	Apr-Mar (m)
(43)	**VARIABLE SUPPLY COSTS (Includes Injections)**													
(44)	Tennessee (Includes ANE and Niagara)													
(45)	TETCO (Includes B&W)													
(46)	TETCO Leidy													
(47)	M3 Delivered													
(48)	Maumee													
(49)	Columbia Broadrun													
(50)	Columbia Eagle and Downingtown													
(51)	TETCO M2													
(52)	Dominion to TETCO FTS													
(53)	Transco Leidy													
(54)	Dawn to Waddington													
(55)	Dawn to East Hereford													
(56)	Algonquin - AIM													
(57)	Millenium													
(58)	DistriGas FCS													
(59)	Hubline													
(60)	Total Pipeline Commodity Charges	$6,727,768	$2,152,097	$2,004,067	$1,829,893	$1,780,004	$2,097,933	$4,810,879	$11,562,101	$15,603,099	$16,352,169	$10,555,794	$10,006,138	$85,481,942
(61)	Hedging Settlements and Amortization	$114,300	$5,471	$15,120	($88,908)	($90,855)	($134,605)	($98,590)	($493,934)	($4,226,993)	($1,472,125)	$374,586	$241,118	($5,855,414)
(62)	Hedging Contracts - Commission & Other Fees	($3,187)	($1,443)	($5,631)	$30,911	$39,550	$72,003	$33,625	($4,886)	($39,459)	($45,742)	($40,867)	($32,962)	$1,912
(63)	Hedging Contracts - Net Carry of Collateral	$255	$405	$208	$323	$429	$371	$506	$74	($54)	$153	$350	$472	$3,493
(64)	Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(65)	Less: Costs of Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(66)	**TOTAL VARIABLE SUPPLY COSTS**	$6,839,136	$2,156,530	$2,013,763	$1,772,220	$1,729,129	$2,035,702	$4,746,420	$11,063,355	$11,336,593	$14,834,456	$10,889,863	$10,214,766	$79,631,933
(67)	Underground Storage	$469,387	$141,440	$19,511	$30,455	$142,381	$70,451	$309,281	$777,835	$1,570,638	$2,645,978	$2,217,253	$1,401,131	$9,795,742
(68)	LNG Withdrawals and Trucking	$489,938	$109,152	$74,782	$84,172	$92,087	$72,823	$82,578	$360,703	$131,722	$862,953	$249,826	$186,423	$2,797,159
(69)	Storage Delivery Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(70)	**TOTAL VARIABLE STORAGE COSTS**	$959,326	$250,592	$94,294	$114,627	$234,468	$143,274	$391,859	$1,138,537	$1,702,360	$3,508,932	$2,467,079	$1,587,555	$12,592,901
(71)	**TOTAL VARIABLE COSTS**	$7,798,461	$2,407,122	$2,108,057	$1,886,847	$1,963,597	$2,178,976	$5,138,279	$12,201,893	$13,038,953	$18,343,387	$13,356,942	$11,802,321	$92,224,834
(72)	**TOTAL SUPPLY COSTS**	$12,439,093	$6,948,796	$5,959,377	$5,812,979	$5,812,220	$6,063,743	$9,207,915	$17,125,026	$23,086,806	$28,854,987	$23,878,099	$22,316,336	$167,505,378

(60) Sum[Lines (44) : (59)]
(66) Sum[Lines (60) : (65)]
(70) Sum[Lines (67) : (69)]
(71) Line (66) + Line (70)
(72) Line (42) + Line (71)

REDACTED

Supply Estimates Actuals for Filing

	Description	Apr-18 Actual (a)	May-18 Actual (b)	Jun-18 Actual (c)	Jul-18 Actual (d)	Aug-18 Actual (e)	Sep-18 Actual (f)	Oct-18 Actual (g)	Nov-18 Actual (h)	Dec-18 Actual (i)	Jan-19 Actual (j)	Feb-19 Actual (k)	Mar-19 Actual (l)	Apr-Mar (m)
(73)	**Storage Costs for FT-2 Calculation**													
(74)	**Storage Fixed Costs - Facilities**	$389,801	$389,827	$389,724	$389,705	$389,905	$389,905	$389,933	$388,862	$388,688	$388,645	$389,486	$389,689	$4,674,171
(75)	**Storage Fixed Costs - Deliveries**	$957,522	$957,522	$957,522	$957,522	$957,522	$957,522	$957,522	$832,774	$6,552,498	$6,552,498	$6,552,498	$6,552,498	$33,745,420
(76)	**Sub-Total Storage Costs**	$1,347,323	$1,347,349	$1,347,246	$1,347,228	$1,347,427	$1,347,427	$1,347,455	$1,221,636	$6,941,186	$6,941,143	$6,941,984	$6,942,187	$38,419,591
(77)	**Tennessee Dracut for Peaking.**	$0	$0	$0	$0	$0	$0	$0	$250,728	$250,727	$250,727	$250,728	$250,085	$1,252,995
(78)	**LNG Demand to DAC**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(79)	**Inventory Financing**	$53,892	$67,526	$77,259	$84,218	$88,985	$96,268	$103,467	$101,836	$98,993	$79,855	$69,290	$65,345	$986,934
(80)	**Supply related LNG O&M Costs**	$47,965	$47,965	$47,965	$47,965	$47,965	$71,771	$71,771	$69,152	$69,152	$69,152	$69,152	$223,335	$883,310
(81)	**Working Capital Requirement**	$3,019	$3,020	$3,019	$3,019	$3,020	$4,583	$4,583	$5,958	$49,328	$49,328	$49,334	$49,335	$227,545
(82)	**Total FT-2 Storage Fixed Costs**	$1,452,199	$1,465,860	$1,475,489	$1,482,429	$1,487,397	$1,520,048	$1,527,276	$1,649,309	$7,409,386	$7,390,205	$7,380,488	$7,530,288	$41,770,374
(83)	**System Storage MDQ (Dth)**	205,567	205,579	206,137	207,296	209,541	209,800	208,142	208,270	239,660	244,556	244,754	244,515	2,633,816
(84)	**FT-2 Storage Cost per MDQ (Dth)**	$7.0644	$7.1304	$7.1578	$7.1513	$7.0984	$7.2452	$7.3377	$7.9191	$30.9163	$30.2189	$30.1547	$30.7968	$15.8593
(85)	Pipeline Variable	$7,798,461	$2,407,122	$2,108,057	$1,886,847	$1,963,597	$2,178,976	$5,138,279	$12,201,893	$13,038,953	$18,343,387	$13,356,942	$11,802,321	$92,224,834
(86)	Less Non-firm Gas Costs	($95,167)	($97,271)	($42,064)	($31,998)	($21,238)	($21,683)	$63,972	($68,259)	($337,805)	($500,059)	($39,023)	($121,613)	($1,312,209)
(87)	Less Company Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(88)	Less Manchester St Balancing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(89)	Plus Cashout	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(90)	Less Mkter W/drawals/Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(91)	Mkter Over-takes/Undertakes	$167,785	$182,778	($61,186)	$21,945	$64,581	$136,403	$81,723	$102,149	$433,324	$692,983	$841,872	$6,299	$2,670,658
(92)	Plus Pipeline Srchg/Credit	$242,528	$234,727	$241,971	$233,523	$239,492	$240,231	$234,434	$241,824	$97,250	$106,714	$102,850	$93,777	$2,309,319
(93)	Less Mkter FT-2 Daily weather true-up	$96,202	($62,170)	($7,401)	($4,021)	($1,810)	$0	($18,332)	($45,849)	($912)	$87,647	($36,924)	($2,593)	$3,839
(94)	**TOTAL FIRM COMMODITY COSTS**	$8,209,810	$2,665,186	$2,239,378	$2,106,295	$2,244,622	$2,533,927	$5,500,076	$12,431,758	$13,230,810	$18,730,672	$14,225,717	$11,778,191	$95,896,441

(76) Line (74) + Line (75)
(82) Sum[Lines (76) : (81)]
(84) Line (82) ÷ Line (83)
(85) Line (71)
(94) Sum[Lines (85) : (93)]

REDACTED

GCR Revenue

	Description	Apr-18 Actual (a)	May-18 Actual (b)	Jun-18 Actual (c)	Jul-18 Actual (d)	Aug-18 Actual (e)	Sep-18 Actual (f)	Oct-18 Actual (g)	Nov-18 Actual (h)	Dec-18 Actual (i)	Jan-19 Actual (j)	Feb-19 Actual (k)	Mar-19 Actual (l)	Apr-Mar (m)
(1)	**I. Fixed Cost Revenue**													
(2)	(a) Low Load dth	3,506,098	1,884,106	735,512	598,017	495,692	462,195	733,926	1,967,849	3,623,285	4,395,055	4,838,129	4,321,115	27,560,979
(3)	Fixed Cost Factor	$1.5395	$1.5517	$1.5573	$1.5619	$1.5609	$1.6257	$1.5584	$2.7598	$3.0769	$3.0864	$3.0730	$3.0729	
(4)	Low Load Revenue	$5,397,759	$2,923,557	$1,145,389	$934,061	$773,704	$751,381	$1,143,766	$5,430,942	$11,148,626	$13,565,005	$14,867,411	$13,278,328	$71,359,928
(5)	(b) High Load dth	73,508	60,427	47,238	38,449	43,286	49,952	49,143	68,252	94,250	97,195	103,754	95,622	821,076
(6)	Fixed Cost Factor	$1.1401	$1.1256	$1.1326	$1.1366	$1.1333	$1.1425	$1.1338	$2.0215	$2.1557	$2.1528	$2.1496	$2.1991	
(7)	High Load Revenue	$83,810	$68,020	$53,504	$43,701	$49,057	$57,068	$55,718	$137,969	$203,177	$209,243	$223,034	$210,285	$1,394,584
(8)	Sub-total throughput Dth	3,579,606	1,944,533	782,750	636,465	538,978	512,147	783,069	2,036,101	3,717,535	4,492,250	4,941,883	4,416,737	28,382,055
(9)	FT-2 Storage Revenue from marketers	$306,325	$370,929	$176,817	$177,698	$179,587	$182,168	$180,904	$181,030	$438,529	$456,099	$834,523	$667,640	$4,152,248
(10)	Manchester Steet Volumes (dth)	1,253	1,440	1,010	1,175	1,027	935	927	1,074	939	276	93	390	
(11)	Fixed cost factor (dth)	1.6027	1.6027	1.6027	1.6027	1.6027	1.5819	1.5819	3.1326	3.1326	3.1326	3.1326	3.1326	
(12)	Manchester Street Revenue	$2,008	$2,307	$1,618	$1,882	$1,645	$1,479	$1,466	$3,365	$2,942	$863	$291	$1,220	$21,088
(13)	**TOTAL Fixed Revenue**	$5,789,902	$3,364,813	$1,377,328	$1,157,343	$1,003,994	$992,096	$1,381,854	$5,753,304	$11,793,274	$14,231,210	$15,925,259	$14,157,473	$76,927,848
(14)	**II. Variable Cost Revenue**													
(15)	(a) Firm Sales dth	3,579,606	1,944,533	782,750	636,465	538,978	512,147	783,069	2,036,101	3,717,535	4,492,250	4,941,883	4,416,737	28,382,055
(16)	Variable Supply Cost Factor	$5.7770	$5.8197	$5.8402	$5.8579	$5.8523	$6.0757	$5.8446	$4.4243	$3.8394	$3.8514	$3.8348	$3.8366	
(17)	Variable Supply Revenue	$20,679,478	$11,316,629	$4,571,452	$3,728,359	$3,154,276	$3,111,649	$4,576,724	$9,008,290	$14,272,982	$17,301,264	$18,951,160	$16,945,374	$127,617,635
(18)	(b) TSS Sales dth	20,288	14,962	31	234	527	11	3,264	4,645	7,989	12,544	18,021	22,110	104,626
(19)	TSS Surcharge Factor	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.2530	$0.0000	$0.0000	$0.0000	
(20)	TSS Surcharge Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$2,021	$0	$0	$0	$2,021
(21)	(c) Default Sales dth	10,571	8,376	1,824	1,291	1,141	5,842	4,501	4,141	13,049	12,180	9,490	4,628	77,033
(22)	Variable Supply Cost Factor	($1.03)	$5.44	($19.11)	$4.33	$6.40	$13.48	$5.05	$6.73	$11.68	$23.50	$10.64	$7.62	
(23)	Variable Supply Revenue	($10,899)	$45,559	($34,852)	$5,587	$7,307	$78,745	$22,734	$27,868	$152,391	$286,217	$101,016	$35,265	$716,938
(24)	(d) Peaking Gas Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(25)	(e) Deferred Responsibility	$25,960	$34,997	$67,253	$69,254	$33,122	$46,650	$63,877	($48,241)	$19,950	($7,423)	($81,618)	$1,903	$225,685
(26)	(e) FT-1 Storage and Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(27)	Manchester Steet Volumes (dth)	1,253	1,440	1,010	1,175	1,027	935	927	1,074	939	276	93	390	
(28)	Variable Supply Cost Factor (dth)	$6.0123	$6.0123	$6.0123	$6.0123	$6.0123	$5.9344	$5.9344	$3.9093	$3.9093	$3.9093	$3.9093	$3.9093	
(29)	Manchester Street Revenue	$7,533	$8,656	$6,071	$7,061	$6,173	$5,548	$5,501	$4,199	$3,671	$1,077	$364	$1,523	$57,376
(30)	**TOTAL Variable Revenue**	$20,702,072	$11,405,840	$4,609,923	$3,810,262	$3,200,878	$3,242,592	$4,668,835	$8,992,116	$14,451,015	$17,581,135	$18,970,922	$16,984,064	$128,619,655
(31)	**Total Gas Cost Revenue (w/o FT-2)**	$26,491,974	$14,770,652	$5,987,251	$4,967,605	$4,204,872	$4,234,688	$6,050,689	$14,745,421	$26,244,289	$31,812,345	$34,896,180	$31,141,537	$205,547,502

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 costs associated with heater gas used at Manchester St. Station

(2) Sch. 6, Sum[lines (24) : (28), (30)]
(3) Line (4) ÷ Line (2)
(5) Sch. 6, Sum[lines (22), (23), (29), (31)]
(6) Line (7) ÷ Line (5)
(8) Line (2) + Line (5)
(10) Monthly Meter Use
(11) Inherent in approved GCR
(12) Line (10) x Line (11)
(13) Line (4) + Line (7) + Line (9) + Line (12)

(15) Line (8)
(16) Line (17) ÷ Line (15)
(18) Sch. 6, line (20)
(19) Company's website
(20) Line (18) x Line (19)
(21) Sch. 6, line (61)
(22) Line (23) ÷ Line (21)
(25) Company Data
(27) Monthly Meter Use

(28) Inherent in approved GCR
(29) Line (27) x Line (28)
(30) Sum[Lines (17), (20), (23):(26), (29)]
(31) Line (13) + Line (30)

REDACTED

WORKING CAPITAL

	Description	Apr-18 Actual (a)	May-18 Actual (b)	Jun-18 Actual (c)	Jul-18 Actual (d)	Aug-18 Actual (e)	Sep-18 Actual (f)	Oct-18 Actual (g)	Nov-18 Actual (h)	Dec-18 Actual (i)	Jan-19 Actual (j)	Feb-19 Actual (k)	Mar-19 Actual (l)	Apr-Mar (m)
(1)	**Supply Fixed Costs**	$4,640,632	$4,541,674	$3,851,320	$3,926,133	$3,848,623	$3,884,767	$4,069,636	$4,923,133	$10,047,853	$10,511,600	$10,521,157	$10,514,015	$75,280,544
(2)	Less: System Pressure to DAC	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	$0	$0	$0	$0	$0	($1,839,600)
(3)	Plus: Supply Related LNG O&M Costs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Total Adjustments	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	$0	$0	$0	$0	$0	($1,839,600)
(5)	Allowable Working Capital Costs	$4,377,832	$4,278,874	$3,588,520	$3,663,333	$3,585,823	$3,621,967	$3,806,836	$4,923,133	$10,047,853	$10,511,600	$10,521,157	$10,514,015	$73,440,944
(6)	Number of Days Lag	21.51	21.51	21.51	21.51	21.51	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
(7)	Working Capital Requirement	$257,992	$252,161	$211,477	$215,886	$211,318	$326,672	$343,345	$444,026	$906,234	$948,060	$948,922	$948,278	
(8)	Cost of Capital	7.26%	7.26%	7.26%	7.26%	7.26%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(9)	Return on Working Capital Requirement	$18,730	$18,307	$15,353	$15,673	$15,342	$23,357	$24,549	$31,748	$64,796	$67,786	$67,848	$67,802	
(10)	Weighted Cost of Debt	2.58%	2.58%	2.58%	2.58%	2.58%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(11)	Interest Expense	$6,656	$6,506	$5,456	$5,570	$5,452	$7,905	$8,309	$10,745	$21,931	$22,943	$22,964	$22,948	
(12)	Taxable Income	$12,074	$11,801	$9,897	$10,103	$9,890	$15,452	$16,240	$21,002	$42,865	$44,843	$44,884	$44,854	
(13)	1 - Combined Tax Rate[2]	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(14)	Return and Tax Requirement	$15,284	$14,938	$12,528	$12,789	$12,519	$19,559	$20,557	$26,585	$54,259	$56,764	$56,815	$56,777	
(15)	**Supply Fixed Working Capital Requirement**	$21,940	$21,444	$17,984	$18,359	$17,971	$27,464	$28,866	$37,331	$76,190	$79,707	$79,779	$79,725	$506,760
(16)	**Supply Variable Costs**	$8,209,810	$2,665,186	$2,239,378	$2,106,295	$2,244,622	$2,533,927	$5,500,076	$12,431,758	$13,230,810	$18,730,672	$14,225,717	$11,778,191	$95,896,441
(17)	Less: Bal. Related Syst. Pressure Commodity to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20)	Allowable Working Capital Costs	$8,209,810	$2,665,186	$2,239,378	$2,106,295	$2,244,622	$2,533,927	$5,500,076	$12,431,758	$13,230,810	$18,730,672	$14,225,717	$11,778,191	$95,896,441
(21)	Number of Days Lag	21.51	21.51	21.51	21.51	21.51	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
(22)	Working Capital Requirement	$483,816	$157,063	$131,970	$124,127	$132,279	$228,539	$496,062	$1,121,242	$1,193,310	$1,689,353	$1,283,043	$1,062,296	
(23)	Cost of Capital	7.26%	7.26%	7.26%	7.26%	7.26%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(24)	Return on Working Capital Requirement	$35,125	$11,403	$9,581	$9,012	$9,603	$16,341	$35,468	$80,169	$85,322	$120,789	$91,738	$75,954	
(25)	Weighted Cost of Debt	2.58%	2.58%	2.58%	2.58%	2.58%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(26)	Interest Expense	$12,482	$4,052	$3,405	$3,202	$3,413	$5,531	$12,005	$27,134	$28,878	$40,882	$31,050	$25,708	
(27)	Taxable Income	$22,643	$7,351	$6,176	$5,809	$6,191	$10,810	$23,464	$53,035	$56,444	$79,906	$60,688	$50,247	
(28)	1 - Combined Tax Rate[2]	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(29)	Return and Tax Requirement	$28,662	$9,305	$7,818	$7,353	$7,836	$13,683	$29,701	$67,133	$71,448	$101,147	$76,820	$63,603	
(30)	**Supply Variable Working Capital Requirement**	$41,144	$13,357	$11,223	$10,556	$11,249	$19,214	$41,706	$94,267	$100,326	$142,030	$107,870	$89,311	$682,251

[1] For the period Apr. 2018 through Oct. 2018, Dkt 4323; and for the period Nov. 2018 through Mar. 2019, Dkt 4770.

[2] For the period Apr. 2018 through Dec. 2018, Dkt 4323; and for the period Jan. 2019 through Mar. 2019, Dkt 4770

(1) Sch.1, line (4)
(2) Sch.1, line (5)
(3) Dkt 4323; Dkt 4770
(4) Line (2) + Line (3)
(5) Line (1) + Line (4)
(6) Dkt 4323; Dkt 4770
(7) [Line (5) x Line (6)] ÷ 365
(8) Dkt 4339; Dkt 4770
(9) Line (7) x Line (8)
(10) Dkt 4339; Dkt 4770
(11) Line (7) x Line (10)
(12) Line (9) - Line (11)
(13) Dkt 4323; Dkt 4770
(14) Line (12) ÷ Line (13)
(15) Line (11) + Line (14)
(16) Sch.1, line (20)
(17) Sch.1, line (21)
(18) Dkt 4323; Dkt 4770
(19) Line (17) + Line (18)
(20) Line (16) + Line (19)
(21) Dkt 4323; Dkt 4770
(22) [Line (20) x Line (21)] ÷ 365
(23) Dkt 4339; Dkt 4770
(24) Line (22) x Line (23)
(25) Dkt 4339; Dkt 4770
(26) Line (22) x Line (25)
(27) Line (24) - Line (26)
(28) Dkt 4323; Dkt 4770
(29) Line (27) ÷ Line (28)
(30) Line (26) + Line (29)

REDACTED

INVENTORY FINANCE

	Description	Apr-18 Actual (a)	May-18 Actual (b)	Jun-18 Actual (c)	Jul-18 Actual (d)	Aug-18 Actual (e)	Sep-18 Actual (f)	Oct-18 Actual (g)	Nov-18 Actual (h)	Dec-18 Actual (i)	Jan-19 Actual (j)	Feb-19 Actual (k)	Mar-19 Actual (l)	Apr-Mar (m)
(1)	**Storage Inventory Balance**	$5,648,954	$6,748,103	$7,942,915	$8,707,995	$9,205,400	$10,308,042	$11,196,336	$10,980,779	$10,290,067	$8,152,003	$6,388,367	$5,560,743	
(2)	Monthly Storage Deferral/Amortization	$3,293	$4,862	$10,626	($20,236)	($59,495)	($131,407)	($164,962)	($160,013)	($120,422)	($74,233)	($32,992)	$1	
(3)	**Subtotal**	$5,652,247	$6,752,965	$7,953,541	$8,687,760	$9,145,905	$10,176,636	$11,031,374	$10,820,767	$10,169,645	$8,077,770	$6,355,375	$5,560,744	
(4)	Cost of Capital	7.26%	7.26%	7.26%	7.26%	7.26%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(5)	Return on Working Capital Requirement	$410,353	$490,265	$577,427	$630,731	$663,993	$727,629	$788,743	$773,685	$727,130	$577,561	$454,409	$397,593	$7,219,520
(6)	Weighted Cost of Debt	2.58%	2.58%	2.58%	2.58%	2.58%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(7)	Interest Charges Financed	$145,828	$174,226	$205,201	$224,144	$235,964	$246,275	$266,959	$261,863	$246,105	$195,482	$153,800	$134,570	$2,490,418
(8)	Taxable Income	$264,525	$316,039	$372,226	$406,587	$428,028	$481,355	$521,784	$511,822	$481,024	$382,079	$300,609	$263,023	
(9)	1 - Combined Tax Rate[1]	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(10)	Return and Tax Requirement	$334,842	$400,049	$471,172	$514,667	$541,808	$609,310	$660,486	$647,876	$608,891	$483,644	$380,518	$332,941	$5,986,204
(11)	Working Capital Requirement	$480,670	$574,276	$676,373	$738,811	$777,772	$855,585	$927,445	$909,739	$854,997	$679,126	$534,318	$467,511	$8,476,623
(12)	Monthly Average	$40,056	$47,856	$56,364	$61,568	$64,814	$71,299	$77,287	$75,812	$71,250	$56,594	$44,527	$38,959	$706,385
(13)	**LNG Inventory Balance**	$1,952,417	$2,775,547	$2,948,436	$3,196,141	$3,410,636	$3,563,891	$3,736,746	$3,714,465	$3,959,875	$3,320,144	$3,534,582	$3,766,155	
(14)	Cost of Capital	7.26%	7.26%	7.26%	7.26%	7.26%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
(15)	Return on Working Capital Requirement	$141,745	$201,505	$214,056	$232,040	$247,612	$254,818	$267,177	$265,584	$283,131	$237,390	$252,723	$269,280	$2,867,062
(16)	Weighted Cost of Debt	2.58%	2.58%	2.58%	2.58%	2.58%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	
(17)	Interest Charges Financed	$50,372	$71,609	$76,070	$82,460	$87,994	$86,246	$90,429	$89,890	$95,829	$80,347	$85,537	$91,141	$987,926
(18)	Taxable Income	$91,373	$129,896	$137,987	$149,579	$159,618	$168,572	$176,748	$175,694	$187,302	$157,043	$167,186	$178,139	
(19)	1 - Combined Tax Rate[1]	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(20)	Return and Tax Requirement	$115,662	$164,425	$174,667	$189,341	$202,048	$213,382	$223,732	$222,398	$237,091	$198,788	$211,628	$225,493	$2,378,654
(21)	Working Capital Requirement	$166,034	$236,034	$250,736	$271,801	$290,042	$299,628	$314,161	$312,288	$332,920	$279,136	$297,164	$316,634	$3,366,580
(22)	Monthly Average	$13,836	$19,669	$20,895	$22,650	$24,170	$24,969	$26,180	$26,024	$27,743	$23,261	$24,764	$26,386	$280,548
(23)	TOTAL GCR Inventory Financing Costs	$53,892	$67,526	$77,259	$84,218	$88,985	$96,268	$103,467	$101,836	$98,993	$79,855	$69,290	$65,345	$986,934

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[1] For the period Apr 2018 through Dec 2018, Dkt 4323; and for the period Jan. 2019 through Mar. 2019, Dkt 4770

(3) Line (1) + Line (2)
(4) Dkt 4323; Dkt 4770
(5) Line (3) x Line (4)
(6) Dkt 4323; Dkt 4770
(7) Line (3) x Line (6)
(8) Line (5) - Line (7)
(9) Dkt 4323; Dkt 4770
(10) Line (8) ÷ Line (9)
(11) Line (7) + Line (10)
(12) Line (11) ÷ 12
(14) Dkt 4323; Dkt 4770
(15) Line (13) x Line (14)
(16) Dkt 4323; Dkt 4770
(17) Line (13) x Line (16)
(18) Line (15) - Line (17)
(19) Dkt 4323; Dkt 4770
(20) Line (18) ÷ Line (19)
(21) Line (17) + Line (20)
(22) Line (21) ÷ 12
(23) Line (12) + Line (22)

REDACTED

Actual Dth Usage for Filing

		Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-Mar
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	THROUGHPUT (Dth)													
	Rate Class													
(1)	**SALES**													
(2)	Residential Non-Heating	41,610	30,778	20,876	17,267	14,401	16,043	17,997	28,624	44,208	51,962	56,127	48,978	388,871
(3)	Residential Non-Heating Low Income	1,176	992	550	458	358	406	497	914	1,605	2,013	2,342	2,560	13,869
(4)	Residential Heating	2,449,113	1,306,376	501,624	399,062	327,622	275,453	496,524	1,400,863	2,525,446	3,077,706	3,353,125	2,973,585	19,086,499
(5)	Residential Heating Low Income	191,545	117,403	50,413	40,182	33,300	38,800	48,836	122,425	224,680	259,884	295,562	274,215	1,697,243
(6)	Small C&I	319,554	154,805	52,206	43,437	41,661	38,485	46,372	155,155	324,135	401,172	469,574	406,681	2,453,236
(7)	Medium C&I	414,692	234,444	118,691	99,018	84,532	101,217	125,311	238,873	446,128	523,894	568,178	521,885	3,476,863
(8)	Large LLF	99,605	52,679	10,910	15,118	7,487	9,085	13,217	42,808	85,435	109,786	123,101	112,566	681,798
(9)	Large HLF	27,181	21,738	20,612	15,327	15,442	18,551	21,143	24,988	35,430	32,075	36,915	35,527	304,930
(10)	Extra Large LLF	11,137	5,738	1,636	966	564	(856)	628	3,443	10,432	11,894	12,332	11,857	69,772
(11)	Extra Large HLF	3,705	4,618	5,200	5,396	13,084	14,952	9,280	13,364	12,047	9,321	6,607	6,774	104,348
(12)	Total Sales	3,559,318	1,929,572	782,719	636,232	538,451	512,136	779,805	2,031,456	3,709,546	4,479,706	4,923,862	4,394,626	28,277,429
(13)	**TSS**													
(14)	Small	895	409	5	0	31	0	63	87	653	1,467	2,927	2,826	9,363
(15)	Medium	11,034	8,187	27	234	496	11	2,975	3,405	5,698	7,429	12,211	16,374	68,079
(16)	Large LLF	8,523	4,065	0	0	0	0	0	792	678	1,824	1,120	1,126	18,127
(17)	Large HLF	(164)	2,302	0	0	0	0	226	362	960	1,825	1,763	1,784	9,057
(18)	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20)	Total TSS	20,288	14,962	31	234	527	11	3,264	4,645	7,989	12,544	18,021	22,110	104,626
(21)	**Sales & TSS THROUGHPUT**													
(22)	Residential Non-Heating	41,610	30,778	20,876	17,267	14,401	16,043	17,997	28,624	44,208	51,962	56,127	48,978	388,871
(23)	Residential Non-Heating Low Income	1,176	992	550	458	358	406	497	914	1,605	2,013	2,342	2,560	13,869
(24)	Residential Heating	2,449,113	1,306,376	501,624	399,062	327,622	275,453	496,524	1,400,863	2,525,446	3,077,706	3,353,125	2,973,585	19,086,499
(25)	Residential Heating Low Income	191,545	117,403	50,413	40,182	33,300	38,800	48,836	122,425	224,680	259,884	295,562	274,215	1,697,243
(26)	Small C&I	320,449	155,214	52,211	43,437	41,692	38,485	46,435	155,242	324,788	402,639	472,501	409,507	2,462,599
(27)	Medium C&I	425,727	242,631	118,718	99,252	85,028	101,228	128,286	242,277	451,826	531,323	580,388	538,259	3,544,942
(28)	Large LLF	108,127	56,744	10,910	15,118	7,487	9,085	13,217	43,600	86,113	111,610	124,222	113,693	699,924
(29)	Large HLF	27,017	24,039	20,612	15,327	15,442	18,551	21,369	25,350	36,391	33,899	38,678	37,311	313,988
(30)	Extra Large LLF	11,137	5,738	1,636	966	564	(856)	628	3,443	10,432	11,894	12,332	11,857	69,772
(31)	Extra Large HLF	3,705	4,618	5,200	5,396	13,084	14,952	9,280	13,364	12,047	9,321	6,607	6,774	104,348
(32)	Total Sales & TSS Throughput	3,579,606	1,944,533	782,750	636,465	538,978	512,147	783,069	2,036,101	3,717,535	4,492,250	4,941,883	4,416,737	28,382,055
(33)	**FT-1 TRANSPORTATION**													
(34)	FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	0
(35)	FT-1 Medium	79,406	56,114	28,324	22,817	20,955	20,870	22,623	42,554	65,561	94,793	108,699	79,637	642,352
(36)	FT-1 Large LLF	131,498	92,626	28,406	18,764	32,310	(2,444)	16,294	54,058	98,982	138,472	175,314	125,222	909,502
(37)	FT-1 Large HLF	46,793	38,856	32,470	28,689	28,219	31,424	33,671	39,348	42,147	50,025	63,686	49,247	484,573
(38)	FT-1 Extra Large LLF	171,030	126,757	46,116	25,013	21,466	22,009	26,872	85,429	156,894	206,744	260,878	198,172	1,347,380
(39)	FT-1 Extra Large HLF	544,355	492,894	435,486	425,787	433,065	404,357	432,611	476,792	495,313	572,912	626,515	482,449	5,822,536
(40)	Default	10,571	8,376	1,824	1,291	1,141	5,842	4,501	4,141	13,049	12,180	9,490	4,628	77,033
(41)	Total FT-1 Transportation	983,653	815,622	572,624	522,361	537,155	482,057	536,572	702,322	871,946	1,075,127	1,244,582	939,355	9,283,376
(42)	**FT-2 TRANSPORTATION**													
(43)	FT-2 Small	17,792	9,661	3,132	1,963	2,288	1,681	3,337	10,714	22,111	27,462	30,579	27,409	158,129
(44)	FT-2 Medium	225,062	142,061	67,418	55,558	46,178	49,653	65,449	145,470	250,911	293,954	318,123	287,000	1,946,836
(45)	FT-2 Large LLF	174,043	107,417	33,875	20,295	10,994	19,235	33,853	110,634	202,760	227,877	254,917	230,433	1,426,332
(46)	FT-2 Large HLF	53,196	39,633	30,068	27,451	25,349	28,130	32,987	45,823	61,380	67,288	72,351	67,250	550,905
(47)	FT-2 Extra Large LLF	2,597	1,203	0	0	0	97	416	2,108	4,630	4,957	5,413	5,780	27,201
(48)	FT-2 Extra Large HLF	46,933	39,757	42,217	31,497	27,478	30,745	36,826	43,568	48,106	49,008	46,506	50,739	493,381
(49)	Total FT-2 Transportation	519,623	339,732	176,710	136,764	112,286	129,541	172,867	358,317	589,897	670,545	727,890	668,612	4,602,783
(50)	**Total THROUGHPUT**													
(51)	Residential Non-Heating	41,610	30,778	20,876	17,267	14,401	16,043	17,997	28,624	44,208	51,962	56,127	48,978	388,871
(52)	Residential Non-Heating Low Income	1,176	992	550	458	358	406	497	914	1,605	2,013	2,342	2,560	13,869
(53)	Residential Heating	2,449,113	1,306,376	501,624	399,062	327,622	275,453	496,524	1,400,863	2,525,446	3,077,706	3,353,125	2,973,585	19,086,499
(54)	Residential Heating Low Income	191,545	117,403	50,413	40,182	33,300	38,800	48,836	122,425	224,680	259,884	295,562	274,215	1,697,243
(55)	Small C&I	338,241	164,875	55,343	45,400	43,980	40,166	49,772	165,956	346,898	430,101	503,080	436,916	2,620,727
(56)	Medium C&I	730,194	440,806	214,459	177,627	152,161	171,751	216,357	430,301	768,298	920,070	1,007,210	904,897	6,134,131
(57)	Large LLF	413,668	256,787	73,190	54,177	50,790	25,876	63,364	208,291	387,855	477,959	554,453	469,348	3,035,758
(58)	Large HLF	127,007	102,528	83,150	71,467	69,010	78,105	88,026	110,521	139,917	151,212	174,715	153,807	1,349,465
(59)	Extra Large LLF	184,765	133,699	47,753	25,980	22,030	21,249	27,916	90,980	171,955	223,594	278,624	215,809	1,444,353
(60)	Extra Large HLF	594,993	537,269	482,903	462,680	473,627	450,053	478,717	533,724	555,466	631,242	679,629	539,961	6,420,265
(61)	Default	10,571	8,376	1,824	1,291	1,141	5,842	4,501	4,141	13,049	12,180	9,490	4,628	77,033
(62)	Total Throughput	5,082,882	3,099,887	1,532,085	1,295,590	1,188,420	1,123,745	1,492,508	3,096,740	5,179,377	6,237,922	6,914,355	6,024,703	42,268,214

Attachment MJP/AEL-3

Attachment MJP/AEL-3
Projected Gas Cost Balances

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4963
Attachment MJP/AEL-3
Page 1 of 1

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

	Description	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov - Oct
		forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	**I. Fixed Cost Deferred**													
(3)	Beginning Under/(Over) Recovery	($6,712,469)	($6,383,879)	($6,940,982)	($10,098,082)	($14,689,719)	($16,547,364)	($18,714,564)	($16,750,701)	($13,790,895)	($10,368,687)	($6,897,173)	($3,449,802)	($6,712,469)
(4)	Fixed Costs (net of capacity release)	$5,314,218	$7,777,234	$7,775,900	$7,775,900	$7,775,900	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$5,584,451	$75,510,312
(5)	NGPMP Credits	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($5,700,000)
(6)	Working Capital	$40,296	$58,973	$58,963	$58,963	$58,963	$42,345	$42,345	$42,345	$42,345	$42,345	$42,345	$42,345	$572,574
(7)	Supply Related LNG O & M	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$829,823
(8)	Total Supply Fixed Costs	$4,948,666	$7,430,359	$7,429,015	$7,429,015	$7,429,015	$5,220,949	$5,220,949	$5,220,949	$5,220,949	$5,220,949	$5,220,949	$5,220,949	$71,212,710
(9)	Fixed - Revenue	($4,597,973)	($7,969,098)	($10,562,632)	($11,989,791)	($9,243,608)	($7,341,115)	($3,208,207)	($2,220,406)	($1,765,443)	($1,725,639)	($1,759,777)	($2,109,531)	($64,493,214)
(10)	Prelim. Ending Under/(Over) Recovery	($6,361,776)	($6,922,617)	($10,074,599)	($14,658,858)	($16,504,312)	($18,667,530)	($16,701,822)	($13,750,158)	($10,335,389)	($6,873,377)	($3,436,001)	($338,384)	
(11)	Month's Average Balance	($6,537,122)	($6,653,248)	($8,507,790)	($12,378,470)	($15,597,016)	($17,607,447)	($17,708,193)	($15,250,429)	($12,063,142)	($8,621,032)	($5,166,587)	($1,894,093)	
(12)	Interest Rate (BOA Prime minus 200 bps)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
(13)	Interest Applied	($17,462)	($18,365)	($23,484)	($30,861)	($43,052)	($47,034)	($48,879)	($40,737)	($33,298)	($23,796)	($13,801)	($5,228)	($345,998)
(14)	Marketer Reconciliation	($4,641)												($4,641)
(15)	Fixed Ending Under/(Over) Recovery	($6,383,879)	($6,940,982)	($10,098,082)	($14,689,719)	($16,547,364)	($18,714,564)	($16,750,701)	($13,790,895)	($10,368,687)	($6,897,173)	($3,449,802)	($343,613)	($343,613)
(16)	**II. Variable Cost Deferred**													
(17)	Beginning Under/(Over) Recovery	$5,231,873	$6,620,939	$8,156,417	$9,773,901	$7,818,072	$6,389,546	$2,159,290	$976,710	$152,615	($296,316)	($672,253)	($910,074)	$5,231,873
(18)	Variable Costs	$7,012,019	$11,625,621	$15,146,894	$13,510,947	$10,405,363	$5,117,929	$2,673,970	$1,713,896	$1,476,655	$1,502,496	$1,669,857	$3,374,375	$75,230,022
(19)	Supply Related System Pressure to DAC	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($13,598)	($163,175)
(20)	Supply Related LNG O & M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(21)	Inventory Financing - LNG	$18,788	$18,202	$11,040	$6,924	$6,386	$9,101	$11,907	$14,666	$14,388	$13,909	$16,948	$16,934	$159,192
(22)	Inventory Financing - UG	$61,515	$50,007	$35,508	$22,241	$12,982	$13,337	$22,073	$30,472	$34,741	$41,187	$51,127	$61,088	$436,278
(23)	Working Capital	$53,067	$88,051	$114,752	$102,347	$78,798	$38,705	$20,173	$12,893	$11,094	$11,290	$12,559	$25,484	$569,212
(24)	Total Variable Costs	$7,156,979	$11,793,470	$15,319,782	$13,654,048	$10,515,118	$5,190,661	$2,739,712	$1,783,517	$1,548,466	$1,580,472	$1,762,079	$3,489,470	$76,533,773
(25)	Variable - Revenue	($5,783,722)	($10,278,359)	($13,727,010)	($15,631,780)	($11,963,225)	($9,432,319)	($3,926,615)	($2,609,118)	($1,997,199)	($1,955,074)	($1,997,790)	($2,462,342)	($81,764,553)
(26)	Prelim. Ending Under/(Over) Recovery	$6,605,130	$8,136,050	$9,749,189	$7,796,169	$6,369,965	$2,147,888	$972,387	$151,108	($296,118)	($670,918)	($907,964)	$117,053	
(27)	Month's Average Balance	$5,918,501	$7,378,495	$8,952,803	$8,785,035	$7,094,018	$4,268,717	$1,565,839	$563,909	($71,752)	($483,617)	($790,109)	($396,511)	
(28)	Interest Rate (BOA Prime minus 200 bps)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
(29)	Interest Applied	$15,810	$20,367	$24,712	$21,902	$19,581	$11,403	$4,322	$1,506	($198)	($1,335)	($2,111)	($1,094)	$114,866
(30)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(31)	Variable Ending Under/(Over) Recovery	$6,620,939	$8,156,417	$9,773,901	$7,818,072	$6,389,546	$2,159,290	$976,710	$152,615	($296,316)	($672,253)	($910,074)	$115,959	$115,959
(32)	**GCR Deferred Summary**													
(33)	Beginning Under/(Over) Recovery	($1,480,596)	$237,061	$1,215,435	($324,181)	($6,871,647)	($10,157,818)	($16,555,273)	($15,773,991)	($13,638,281)	($10,665,003)	($7,569,426)	($4,359,877)	($1,480,596)
(34)	Gas Costs	$12,402,337	$19,483,597	$23,003,535	$21,367,589	$18,262,004	$10,783,121	$8,339,163	$7,379,089	$7,141,847	$7,167,689	$7,335,049	$9,039,567	$151,704,585
(35)	Inventory Finance	$80,303	$68,209	$46,548	$29,165	$19,368	$22,438	$33,980	$45,139	$49,129	$55,096	$68,075	$78,022	$595,470
(36)	Working Capital	$93,363	$147,024	$173,714	$161,309	$137,761	$81,050	$62,518	$55,238	$53,439	$53,635	$54,904	$67,829	$1,141,786
(37)	NGPMP Credits	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($5,700,000)
(38)	Total Costs	$12,101,004	$19,223,829	$22,748,797	$21,083,063	$17,944,133	$10,411,609	$7,960,661	$7,004,465	$6,769,415	$6,801,420	$6,983,028	$8,710,418	$147,741,842
(39)	Revenue	($10,381,695)	($18,247,457)	($24,289,642)	($27,621,571)	($21,206,833)	($16,773,434)	($7,134,822)	($4,829,524)	($3,762,642)	($3,680,713)	($3,757,567)	($4,571,873)	($146,257,767)
(40)	Prelim. Ending Under/(Over) Recovery	$238,713	$1,213,433	($325,409)	($6,862,688)	($10,134,347)	($16,519,642)	($15,729,434)	($13,599,050)	($10,631,507)	($7,544,295)	($4,343,965)	($221,331)	$3,479
(41)	Month's Average Balance	($620,941)	$725,247	$445,013	($3,593,435)	($8,502,997)	($13,338,730)	($16,142,354)	($14,686,520)	($12,134,894)	($9,104,649)	($5,956,696)	($2,290,604)	
(42)	Interest Rate (BOA Prime minus 200 bps)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
(43)	Interest Applied	($1,652)	$2,002	$1,228	($8,959)	($23,471)	($35,631)	($44,557)	($39,231)	($33,496)	($25,131)	($15,912)	($6,323)	($231,132)
(44)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(45)	Ending Under/(Over) Recovery W/ Interest	$237,061	$1,215,435	($324,181)	($6,871,647)	($10,157,818)	($16,555,273)	($15,773,991)	($13,638,281)	($10,665,003)	($7,569,426)	($4,359,877)	**($227,654)**	($227,654)

(3) MJP/AEL-7, Line (17)(m)
(4) MJP/AEL-1, pg 2, Line (1)
(5) EDA/SAJ-1
(6) MJP/AEL-1, pg 9, Line (17)
(7) MJP/AEL-1, pg 2, Line (8) ÷ 12
(8) Sum[(4)-(7)]
(9) MJP/AEL-1, pg 8, Line (10)
(10) Sum[Lines (3), (8), (9)]
(11) [Lines (3) + Line (10)] ÷ 2
(13) [Line (11) x Line (12)] ÷ 365 x Line (1)
(14) MJP/AEL-7, Pg 2, Line (50)
(15) Sum[Lines (10), (13), (14)]
(17) Nov-18: MJP/AEL-1, pg 7, Line (35)(m)
(18) MJP/AEL-1, pg 6, Line (74)
(20) MJP/AEL-1, pg 3, Line (8) ÷ 12
(21) MJP/AEL-1, pg 11, Line (22)
(22) MJP/AEL-1, pg 11, Line (12)
(23) MJP/AEL-1, pg 9, Line (32)
(24) Sum[Lines (18)-(23)]
(25) MJP/AEL-1, pg 8, Line (15)
(26) Sum[Lines (17), (24), (25)]
(27) [Line (17) + Line (26)] ÷ 2
(29) [Line (27) x Line (28)] ÷ 365 x Line (1)
(31) Sum[Lines (26), (29), (30)]
(33) Line (3) + Line (17)
(34) Sum[Lines (4),(7),(14),(18)-(20)]
(35) Line (21) + Line (22)
(36) Line (5) + Line (23)
(37) Line (5)
(38) Sum[Lines (34)-(37)]
(39) Line (9) + Line (25)
(40) Sum[Lines (33), (38), (39)]
(41) [Lines (33) + Line (40)] ÷ 2
(43) Line (13) + Line (29)
(44) Line (30)
(45) Sum[Lines (40), (43), (44)]

Attachment MJP/AEL-4

Attachment MJP/AEL-4
Bill Impact Analysis
Includes the proposed GCR And DAC Factors

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Heating:

(1)									Difference due to:			
(2)	Annual	Proposed	Current				DAC				
(3)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(4)											
(5)	548	$844.37	$940.09	($95.72)	-10.2%	($95.31)	$2.46	$0.00	$0.00	$0.00	($2.87)
(6)	608	$916.82	$1,022.99	($106.18)	-10.4%	($105.74)	$2.75	$0.00	$0.00	$0.00	($3.19)
(7)	667	$988.00	$1,104.51	($116.51)	-10.5%	($116.02)	$3.01	$0.00	$0.00	$0.00	($3.50)
(8)	726	$1,059.22	$1,186.02	($126.79)	-10.7%	($126.27)	$3.28	$0.00	$0.00	$0.00	($3.80)
(9)	785	$1,130.37	$1,267.48	($137.11)	-10.8%	($136.52)	$3.52	$0.00	$0.00	$0.00	($4.11)
(10)	845	$1,202.81	$1,350.39	($147.58)	-10.9%	($146.95)	$3.80	$0.00	$0.00	$0.00	($4.43)
(11)	905	$1,275.24	$1,433.31	($158.07)	-11.0%	($157.41)	$4.08	$0.00	$0.00	$0.00	($4.74)
(12)	964	$1,346.37	$1,514.72	($168.35)	-11.1%	($167.65)	$4.35	$0.00	$0.00	$0.00	($5.05)
(13)	1,023	$1,417.57	$1,596.23	($178.66)	-11.2%	($177.92)	$4.62	$0.00	$0.00	$0.00	($5.36)
(14)	1,082	$1,488.80	$1,677.76	($188.96)	-11.3%	($188.17)	$4.88	$0.00	$0.00	$0.00	($5.67)
(15)	1,142	$1,561.25	$1,760.72	($199.46)	-11.3%	($198.59)	$5.11	$0.00	$0.00	$0.00	($5.98)

Residential Heating Low Income:

(16)								Difference due to:				
(17)	Annual	Proposed	Current				Total Bill	DAC				
(18)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(19)												
(20)	548	$627.36	$699.13	($71.78)	-10.3%	($95.31)	$23.21	$2.48	$0.00	$0.00	$0.00	($2.15)
(21)	608	$681.03	$760.67	($79.64)	-10.5%	($105.74)	$25.75	$2.74	$0.00	$0.00	$0.00	($2.39)
(22)	667	$733.78	$821.16	($87.38)	-10.6%	($116.02)	$28.25	$3.01	$0.00	$0.00	$0.00	($2.62)
(23)	726	$786.55	$881.66	($95.10)	-10.8%	($126.27)	$30.75	$3.27	$0.00	$0.00	$0.00	($2.85)
(24)	785	$839.28	$942.11	($102.84)	-10.9%	($136.52)	$33.25	$3.52	$0.00	$0.00	$0.00	($3.09)
(25)	845	$892.95	$1,003.65	($110.69)	-11.0%	($146.95)	$35.79	$3.79	$0.00	$0.00	$0.00	($3.32)
(26)	905	$946.63	$1,065.19	($118.56)	-11.1%	($157.41)	$38.34	$4.07	$0.00	$0.00	$0.00	($3.56)
(27)	964	$999.33	$1,125.61	($126.28)	-11.2%	($167.65)	$40.83	$4.33	$0.00	$0.00	$0.00	($3.79)
(28)	1,023	$1,052.08	$1,186.11	($134.03)	-11.3%	($177.92)	$43.34	$4.58	$0.00	$0.00	$0.00	($4.02)
(29)	1,082	$1,104.88	$1,246.60	($141.73)	-11.4%	($188.17)	$45.83	$4.87	$0.00	$0.00	$0.00	($4.25)
(30)	1,142	$1,158.58	$1,308.14	($149.57)	-11.4%	($198.59)	$48.36	$5.15	$0.00	$0.00	$0.00	($4.49)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Non-Heating:

(31)						Difference due to:					
(32)	Annual	Proposed	Current				DAC				
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$362.07	$374.68	($12.61)	-3.4%	($19.65)	$7.42	$0.00	$0.00	$0.00	($0.38)
(36)	158	$379.46	$393.27	($13.81)	-3.5%	($21.55)	$8.15	$0.00	$0.00	$0.00	($0.41)
(37)	172	$396.86	$411.89	($15.03)	-3.6%	($23.45)	$8.87	$0.00	$0.00	$0.00	($0.45)
(38)	189	$418.00	$434.50	($16.49)	-3.8%	($25.77)	$9.77	$0.00	$0.00	$0.00	($0.49)
(39)	202	$434.16	$451.82	($17.66)	-3.9%	($27.55)	$10.42	$0.00	$0.00	$0.00	($0.53)
(40)	220	$456.50	$475.74	($19.24)	-4.0%	($30.02)	$11.36	$0.00	$0.00	$0.00	($0.58)
(41)	238	$478.92	$499.69	($20.77)	-4.2%	($32.45)	$12.30	$0.00	$0.00	$0.00	($0.62)
(42)	251	$495.09	$517.00	($21.91)	-4.2%	($34.22)	$12.97	$0.00	$0.00	$0.00	($0.66)
(43)	268	$516.15	$539.60	($23.45)	-4.3%	($36.56)	$13.81	$0.00	$0.00	$0.00	($0.70)
(44)	282	$533.56	$558.19	($24.63)	-4.4%	($38.46)	$14.57	$0.00	$0.00	$0.00	($0.74)
(45)	297	$552.21	$578.16	($25.95)	-4.5%	($40.50)	$15.33	$0.00	$0.00	$0.00	($0.78)

Residential Non-Heating Low Income:

(46)							Difference due to:					
(47)	Annual	Proposed	Current				Total Bill	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$270.00	$279.44	($9.43)	-3.4%	($19.65)	$3.05	$7.45	$0.00	$0.00	$0.00	($0.28)
(51)	158	$282.90	$293.27	($10.37)	-3.5%	($21.55)	$3.35	$8.14	$0.00	$0.00	$0.00	($0.31)
(52)	172	$295.79	$307.05	($11.26)	-3.7%	($23.45)	$3.64	$8.89	$0.00	$0.00	$0.00	($0.34)
(53)	189	$311.45	$323.82	($12.37)	-3.8%	($25.77)	$4.00	$9.77	$0.00	$0.00	$0.00	($0.37)
(54)	202	$323.43	$336.66	($13.23)	-3.9%	($27.55)	$4.28	$10.44	$0.00	$0.00	$0.00	($0.40)
(55)	220	$340.00	$354.43	($14.43)	-4.1%	($30.02)	$4.67	$11.36	$0.00	$0.00	$0.00	($0.43)
(56)	238	$356.61	$372.20	($15.60)	-4.2%	($32.45)	$5.04	$12.28	$0.00	$0.00	$0.00	($0.47)
(57)	251	$368.60	$385.02	($16.42)	-4.3%	($34.22)	$5.31	$12.98	$0.00	$0.00	$0.00	($0.49)
(58)	268	$384.22	$401.79	($17.57)	-4.4%	($36.56)	$5.68	$13.84	$0.00	$0.00	$0.00	($0.53)
(59)	282	$397.14	$415.61	($18.47)	-4.4%	($38.46)	$5.97	$14.57	$0.00	$0.00	$0.00	($0.55)
(60)	297	$410.95	$430.41	($19.46)	-4.5%	($40.50)	$6.29	$15.33	$0.00	$0.00	$0.00	($0.58)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I Small:

(61)						Difference due to:					
(62)	Annual	Proposed	Current				DAC				
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(64)											
(65)	830	$1,236.91	$1,374.60	($137.69)	-10.0%	($144.37)	$10.81	$0.00	$0.00	$0.00	($4.13)
(66)	919	$1,335.24	$1,487.69	($152.45)	-10.2%	($159.85)	$11.97	$0.00	$0.00	$0.00	($4.57)
(67)	1,010	$1,435.89	$1,603.43	($167.54)	-10.4%	($175.64)	$13.13	$0.00	$0.00	$0.00	($5.03)
(68)	1,099	$1,534.28	$1,716.59	($182.32)	-10.6%	($191.11)	$14.26	$0.00	$0.00	$0.00	($5.47)
(69)	1,187	$1,631.59	$1,828.52	($196.94)	-10.8%	($206.44)	$15.41	$0.00	$0.00	$0.00	($5.91)
(70)	1,277	$1,731.10	$1,942.93	($211.82)	-10.9%	($222.07)	$16.60	$0.00	$0.00	$0.00	($6.35)
(71)	1,367	$1,830.62	$2,057.34	($226.72)	-11.0%	($237.70)	$17.78	$0.00	$0.00	$0.00	($6.80)
(72)	1,456	$1,929.01	$2,170.51	($241.51)	-11.1%	($253.20)	$18.94	$0.00	$0.00	$0.00	($7.25)
(73)	1,544	$2,026.37	$2,282.44	($256.07)	-11.2%	($268.47)	$20.08	$0.00	$0.00	$0.00	($7.68)
(74)	1,635	$2,126.98	$2,398.13	($271.15)	-11.3%	($284.29)	$21.27	$0.00	$0.00	$0.00	($8.13)
(75)	1,725	$2,226.44	$2,512.52	($286.07)	-11.4%	($299.95)	$22.46	$0.00	$0.00	$0.00	($8.58)

C & I Medium:

(76)						Difference due to:					
(77)	Annual	Proposed	Current				DAC				
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(79)											
(80)	6,907	$7,586.12	$8,866.39	($1,280.27)	-14.4%	($1,201.12)	($40.74)	$0.00	$0.00	$0.00	($38.41)
(81)	7,650	$8,288.09	$9,706.11	($1,418.02)	-14.6%	($1,330.34)	($45.14)	$0.00	$0.00	$0.00	($42.54)
(82)	8,391	$8,987.78	$10,543.14	($1,555.36)	-14.8%	($1,459.19)	($49.51)	$0.00	$0.00	$0.00	($46.66)
(83)	9,136	$9,691.48	$11,384.90	($1,693.42)	-14.9%	($1,588.74)	($53.88)	$0.00	$0.00	$0.00	($50.80)
(84)	9,880	$10,394.38	$12,225.75	($1,831.37)	-15.0%	($1,718.14)	($58.29)	$0.00	$0.00	$0.00	($54.94)
(85)	10,623	$11,096.39	$13,065.47	($1,969.07)	-15.1%	($1,847.32)	($62.68)	$0.00	$0.00	$0.00	($59.07)
(86)	11,366	$11,798.42	$13,905.26	($2,106.85)	-15.2%	($1,976.57)	($67.07)	$0.00	$0.00	$0.00	($63.21)
(87)	12,111	$12,502.07	$14,746.99	($2,244.92)	-15.2%	($2,106.09)	($71.48)	$0.00	$0.00	$0.00	($67.35)
(88)	12,855	$13,205.00	$15,587.80	($2,382.80)	-15.3%	($2,235.47)	($75.85)	$0.00	$0.00	$0.00	($71.48)
(89)	13,596	$13,904.68	$16,424.81	($2,520.13)	-15.3%	($2,364.33)	($80.20)	$0.00	$0.00	$0.00	($75.60)
(90)	14,340	$14,607.54	$17,265.61	($2,658.07)	-15.4%	($2,493.73)	($84.60)	$0.00	$0.00	$0.00	($79.74)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Large:

(91)						Difference due to:					
(92)	Annual	Proposed	Current				DAC				
(93)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(94)											
(95)	37,587	$39,828.18	$45,842.08	($6,013.90)	-13.1%	($6,536.37)	$702.89	$0.00	$0.00	$0.00	($180.42)
(96)	41,634	$43,848.69	$50,510.13	($6,661.44)	-13.2%	($7,240.16)	$778.56	$0.00	$0.00	$0.00	($199.84)
(97)	45,683	$47,871.63	$55,180.91	($7,309.28)	-13.2%	($7,944.27)	$854.27	$0.00	$0.00	$0.00	($219.28)
(98)	49,731	$51,893.64	$59,850.61	($7,956.97)	-13.3%	($8,648.22)	$929.96	$0.00	$0.00	$0.00	($238.71)
(99)	53,777	$55,913.25	$64,517.54	($8,604.29)	-13.3%	($9,351.81)	$1,005.65	$0.00	$0.00	$0.00	($258.13)
(100)	57,825	$59,935.28	$69,187.28	($9,252.00)	-13.4%	($10,055.77)	$1,081.33	$0.00	$0.00	$0.00	($277.56)
(101)	61,873	$63,957.34	$73,857.04	($9,899.70)	-13.4%	($10,759.74)	$1,157.03	$0.00	$0.00	$0.00	($296.99)
(102)	65,920	$67,977.83	$78,525.02	($10,547.19)	-13.4%	($11,463.48)	$1,232.71	$0.00	$0.00	$0.00	($316.42)
(103)	69,967	$71,998.95	$83,193.65	($11,194.70)	-13.5%	($12,167.25)	$1,308.39	$0.00	$0.00	$0.00	($335.84)
(104)	74,016	$76,021.91	$87,864.42	($11,842.52)	-13.5%	($12,871.36)	$1,384.12	$0.00	$0.00	$0.00	($355.28)
(105)	78,063	$80,042.40	$92,532.46	($12,490.05)	-13.5%	($13,575.15)	$1,459.80	$0.00	$0.00	$0.00	($374.70)

C & I HLF Large:

(106)						Difference due to:					
(107)	Annual	Proposed	Current				DAC				
(108)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(109)											
(110)	41,956	$36,599.56	$42,097.10	($5,497.54)	-13.1%	($5,722.81)	$390.20	$0.00	$0.00	$0.00	($164.93)
(111)	46,471	$40,270.98	$46,360.16	($6,089.18)	-13.1%	($6,338.65)	$432.15	$0.00	$0.00	$0.00	($182.68)
(112)	50,991	$43,946.01	$50,627.41	($6,681.40)	-13.2%	($6,955.18)	$474.22	$0.00	$0.00	$0.00	($200.44)
(113)	55,507	$47,618.20	$54,891.31	($7,273.11)	-13.3%	($7,571.15)	$516.23	$0.00	$0.00	$0.00	($218.19)
(114)	60,028	$51,293.91	$59,159.44	($7,865.54)	-13.3%	($8,187.82)	$558.25	$0.00	$0.00	$0.00	($235.97)
(115)	64,545	$54,966.78	$63,424.16	($8,457.38)	-13.3%	($8,803.95)	$600.29	$0.00	$0.00	$0.00	($253.72)
(116)	69,062	$58,639.63	$67,688.88	($9,049.25)	-13.4%	($9,420.05)	$642.28	$0.00	$0.00	$0.00	($271.48)
(117)	73,583	$62,315.37	$71,957.02	($9,641.65)	-13.4%	($10,036.71)	$684.31	$0.00	$0.00	$0.00	($289.25)
(118)	78,099	$65,987.53	$76,220.92	($10,233.39)	-13.4%	($10,652.69)	$726.30	$0.00	$0.00	$0.00	($307.00)
(119)	82,619	$69,662.55	$80,488.19	($10,825.64)	-13.4%	($11,269.23)	$768.36	$0.00	$0.00	$0.00	($324.77)
(120)	87,137	$73,337.06	$84,754.71	($11,417.65)	-13.5%	($11,885.49)	$810.37	$0.00	$0.00	$0.00	($342.53)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Extra-Large:

(121)							Difference due to:				
(122)	Annual	Proposed	Current				DAC				
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(124)											
(125)	233,835	$184,042.28	$222,829.96	($38,787.68)	-17.4%	($40,663.91)	$3,039.86	$0.00	$0.00	$0.00	($1,163.63)
(126)	259,019	$203,196.14	$246,161.23	($42,965.08)	-17.5%	($45,043.39)	$3,367.26	$0.00	$0.00	$0.00	($1,288.95)
(127)	284,197	$222,346.03	$269,487.59	($47,141.56)	-17.5%	($49,421.86)	$3,694.55	$0.00	$0.00	$0.00	($1,414.25)
(128)	309,381	$241,499.81	$292,818.82	($51,319.01)	-17.5%	($53,801.38)	$4,021.94	$0.00	$0.00	$0.00	($1,539.57)
(129)	334,562	$260,651.73	$316,147.61	($55,495.89)	-17.6%	($58,180.32)	$4,349.31	$0.00	$0.00	$0.00	($1,664.88)
(130)	359,745	$279,804.92	$339,478.03	($59,673.11)	-17.6%	($62,559.64)	$4,676.72	$0.00	$0.00	$0.00	($1,790.19)
(131)	384,928	$298,958.07	$362,808.52	($63,850.45)	-17.6%	($66,939.00)	$5,004.06	$0.00	$0.00	$0.00	($1,915.51)
(132)	410,110	$318,110.56	$386,138.10	($68,027.54)	-17.6%	($71,318.13)	$5,331.42	$0.00	$0.00	$0.00	($2,040.83)
(133)	435,293	$337,263.77	$409,468.55	($72,204.78)	-17.6%	($75,697.47)	$5,658.83	$0.00	$0.00	$0.00	($2,166.14)
(134)	460,471	$356,413.62	$432,794.86	($76,381.24)	-17.6%	($80,075.91)	$5,986.11	$0.00	$0.00	$0.00	($2,291.44)
(135)	485,655	$375,567.46	$456,126.11	($80,558.65)	-17.7%	($84,455.40)	$6,313.51	$0.00	$0.00	$0.00	($2,416.76)

C & I HLF Extra-Large:

(136)							Difference due to:				
(137)	Annual	Proposed	Current				DAC				
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(139)											
(140)	486,528	$328,197.51	$393,101.35	($64,903.85)	-16.5%	($66,362.43)	$3,405.70	$0.00	$0.00	$0.00	($1,947.12)
(141)	538,924	$362,875.41	$434,769.01	($71,893.60)	-16.5%	($73,509.23)	$3,772.44	$0.00	$0.00	$0.00	($2,156.81)
(142)	591,320	$397,552.44	$476,435.75	($78,883.31)	-16.6%	($80,656.04)	$4,139.23	$0.00	$0.00	$0.00	($2,366.50)
(143)	643,718	$432,231.46	$518,104.79	($85,873.33)	-16.6%	($87,803.16)	$4,506.03	$0.00	$0.00	$0.00	($2,576.20)
(144)	696,109	$466,905.58	$559,767.94	($92,862.36)	-16.6%	($94,949.27)	$4,872.78	$0.00	$0.00	$0.00	($2,785.87)
(145)	748,506	$501,584.08	$601,436.29	($99,852.22)	-16.6%	($102,096.20)	$5,239.55	$0.00	$0.00	$0.00	($2,995.57)
(146)	800,903	$536,262.47	$643,104.61	($106,842.13)	-16.6%	($109,243.18)	$5,606.31	$0.00	$0.00	$0.00	($3,205.26)
(147)	853,294	$570,936.62	$684,767.78	($113,831.16)	-16.6%	($116,389.31)	$5,973.08	$0.00	$0.00	$0.00	($3,414.93)
(148)	905,692	$605,615.69	$726,436.85	($120,821.16)	-16.6%	($123,536.40)	$6,339.87	$0.00	$0.00	$0.00	($3,624.63)
(149)	958,088	$640,292.73	$768,103.63	($127,810.91)	-16.6%	($130,683.20)	$6,706.62	$0.00	$0.00	$0.00	($3,834.33)
(150)	1,010,485	$674,971.15	$809,771.96	($134,800.80)	-16.6%	($137,830.17)	$7,073.39	$0.00	$0.00	$0.00	($4,044.02)

Attachment MJP/AEL-5

REDACTED

Attachment MJP/AEL-5
FT-2 Demand Rate

REDACTED

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

	Item (a)	Reference (b)	Proposed (c)	Billing Units (d)
(1)	FT-2 Demand Usage (Dt) Nov 2019 - Oct 2020	Pg 2, Line (21)	$12.4637	Dth/Mth
(2)	Weighted Average Upstream Pipeline Transportation Cost	EDA/SAJ-1	$0.8143	Per Dth of capacity
(3)	Storage and Peaking charge for FT-1 firm transportation Customers eligible for TSS	Pg 3, Line (5)	$1.0762	Per Dth

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

		Source			
	Description (a)	Reference (b)	Line # (c)	Amount (d)	
(1)	Storage Fixed Costs	MJP/AEL-1 pg 5	Line (41)	[redacted]	
	Less:				
(2)	System Pressure to DAC			$0	
(3)	Credits			$0	
(4)	Refunds			$0	
(5)	Total Credits	Sum [(2)-(4)]		$0	
	Plus:				
(6)	Supply Related LNG O&M Costs	MJP/AEL-1 Pg 2	Line (8)	$829,823	
(7)	Working Capital Requirement	MJP/AEL-1 pg 10	Line (48)	$189,358	
(8)	Tennessee Dracut for peaking / FT Demand Everett	MJP/AEL-1 pg 4	Line (4) + Line (5)	$2,507,274	
(9)	Total Additions	Sum [(6)-(8)]		$3,526,455	
(10)	Total Storage Fixed Costs	(1) + (5) + (9)		[redacted]	
	Inventory Financing				
(11)	Underground	MJP/AEL-1 pg 11	Line (12)	$436,278	
(12)	LNG	MJP/AEL-1 pg 11	Line (22)	$159,192	
(13)	Total Storage Fixed Costs	(10) + (11) + (12)		[redacted]	
(14)	LNG Storage MDQ (Dth)	MJP/AEL-1 pg 13	Line (14)	[redacted]	
(15)	AGT	EDA/SAJ-1		[redacted]	
(16)	TENN	EDA/SAJ-1		[redacted]	
(17)	Total Storage MDQ	Sum [(14)-(16)]		[redacted]	
(18)	Storage MDQ X 12 Months	(17) x 12		[redacted]	MDCQ Dth
(19)	FT- 2 Demand Rate	(13) ÷ (18)		$12.2257	per MDCQ Dth
(20)	Uncollectible %	Docket 4770		1.91%	
(21)	Total FT-2 Demand Rate adjusted for Uncollectibles	(19) ÷ [(1 - (20)]		$12.4637	per MDCQ Dth
(22)	MDQ-U	Mkter MDQ Forecast		4,759	
(23)	MDQ-P	Mkter MDQ Forecast		18,353	
(24)	Marketer MDQs	(22) + (23)		23,112	Dth/Mth
(25)	FT-2 Storage Costs	(19) x (24) x 12 Months		**$3,390,750**	

REDACTED

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

		Source			
	Description (a)	Reference (b)	Line # (c)	Amount (d)	
(1)	Total Storage Fixed Costs	Pg 2	Line (13)	[redacted]	
(2)	Usage (Dth) Nov 2019 - Oct 2020	MJP/AEL-1, pg 2	Line (17)	[redacted]	
(3)	Volumetric Rate	(1) ÷ (2)		$1.0557	
(4)	Uncollectible %	Docket 4770		1.91%	
(5)	Volumetric Rate Including Uncollectible	(3) ÷ [1 - (4)]		$1.0762	per dth
(6)	Storage & Peaking charge applied to FT-1 customers eligible for TSS	(5) ÷ 10		$0.1076	per therm

Attachment MJP/AEL-6

Attachment MJP/AEL-6
FT-2 Capacity Allocator Percentages

RI Gas Company
Capacity Assignment Table

			% of Peak Day Requirement				% of Total Capacity		
			Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	HLF	Res - Non-Heating	59.0%	8.0%	33.0%	100.0%	1.0%	0.8%	0.8%
2	HLF	Res - Non-Heating LI	59.0%	8.0%	33.0%	100.0%			
3	LLF	Res - Heating	47.0%	11.0%	42.0%	100.0%	58.8%	61.2%	61.2%
4	LLF	Res - Heating LI	47.0%	11.0%	42.0%	100.0%			
5	LLF	Small	47.0%	11.0%	42.0%	100.0%	7.6%	8.0%	8.0%
6	LLF	Med	47.0%	11.0%	42.0%	100.0%	9.5%	9.1%	9.1%
7	LLF	Large Low Load	47.0%	11.0%	42.0%	100.0%	2.0%	2.1%	2.1%
8	HLF	Large High Load	59.0%	8.0%	33.0%	100.0%	0.7%	0.4%	0.4%
9	LLF	XL Low Load	47.0%	11.0%	42.0%	100.0%	0.2%	0.2%	0.2%
10	HLF	XL High Load	59.0%	8.0%	33.0%	100.0%	0.1%	0.0%	0.0%
11	HLF	High Load Factor	59.0%	8.0%	33.0%	100.0%	8.4%	5.4%	5.4%
12	LLF	Low Load Factor	47.0%	11.0%	42.0%	100.0%	91.6%	94.6%	94.6%
13		Total	48.0%	11.0%	41.0%	100.0%	100.0%	100.0%	100.0%

Attachment MJP/AEL-7

Attachment MJP/AEL-7
Marketer Reconciliation

2017-18 & 2018-19 Annual Marketer Reconciliation

	Description (a)	# of days (b)	Tetco ELA/Algonquin (c)	Tetco WLA/Algonquin (d)	Tennessee Zone 1 to NEGC (e)	Tetco STX/Algonquin (f)	Algonquin @ Lambertville, NJ (g)	Columbia (Maumee/Downington) (h)	Tennessee 6 to 6 Dracut (i)	Total (j) = Sum[(c) : (i)]
	2018-2019 Marketer Reconciliation									
	Month of activity									
(1)	Nov-18	30	194,970	255,000	285,000	121,320	74,340	87,300	6,330	1,024,260
(2)	Dec-18	31	201,500	263,500	294,500	125,333	79,329	93,000	12,059	1,069,221
(3)	Jan-19	31	201,500	263,500	294,500	125,364	78,864	93,000	9,393	1,066,121
(4)	Feb-19	28	182,000	238,000	266,000	113,232	71,400	84,000	9,100	963,732
(5)	Mar-19	31	201,469	263,500	294,500	125,364	78,895	93,000	8,928	1,065,656
(6)	Apr-19	30	195,000	255,000	285,000	121,320	76,230	90,000	8,370	1,030,920
(7)	May-19	31	201,500	263,500	294,500	125,364	80,135	93,000	13,888	1,071,887
(8)	Jun-19	30	194,970	254,970	284,970	121,320	77,640	90,000	14,250	1,038,120
(9)	Jul-19	31	194,970	254,970	284,970	121,320	77,640	90,000	14,250	1,038,120
(10)	Aug-19	31	194,970	254,970	284,970	121,320	77,640	90,000	14,250	1,038,120
(11)	Sep-19	30	194,970	254,970	284,970	121,320	77,640	90,000	14,250	1,038,120
(12)	Oct-19	31	194,970	254,970	284,970	121,320	77,640	90,000	14,250	1,038,120
(13)	Total		2,352,789	3,076,850	3,438,850	1,463,897	927,393	1,083,300	139,318	12,482,397
	Approved									
(14)	System Average		$0.7693	$0.7693	$0.7693	$0.7693	$0.7693	$0.7693	$0.7693	
(15)	Path		$0.7847	$0.8774	$1.0298	$1.1580	$0.5192	$0.2702	$2.2692	
(16)	Credit/Surcharge		($0.0154)	($0.1081)	($0.2605)	($0.3887)	$0.2501	$0.4991	($1.4999)	
	Revised									
(17)	System Average		$0.7659	$0.7659	$0.7659	$0.7659	$0.7659	$0.7659	$0.7659	
(18)	Path		$0.7847	$0.8774	$1.0163	$1.1580	$0.5192	$0.2702	$2.2659	
(19)	Credit/Surcharge		($0.0188)	($0.1115)	($0.2504)	($0.3921)	$0.2467	$0.4957	($1.5000)	
(20)	Variance_Approved Surcharge/Credit vs. Revised Surch		($0.0034)	($0.0034)	$0.0101	($0.0034)	($0.0034)	($0.0034)	($0.0001)	
(21)	Annual MDCQ		2,352,789	3,076,850	3,438,850	1,463,897	927,393	1,083,300	139,318	12,482,397
(22)	Updated 2018-19 Marketer Reconciliation Adjustment		($7,999)	($10,461)	$34,732	($4,977)	($3,153)	($3,683)	($14)	$4,444

(13): Sum[Lines (1) : (12)]
(14) & (15): Dkt 4872 NGC-4 filed on August 31, 2018
(16): Line (14) - Line (15)
(19): Line (17) - Line (18)
(20): Line (19) - Line (16)
(21): Line (13)
(22): Line (20) x Line (21)

2017-18 & 2018-19 Annual Marketer Reconciliation

	Description (a)	# of days (b)	Tetco ELA/Algonquin (c)	Tetco WLA/Algonquin (d)	Tennessee Zone 1 to NEGC (e)	Tetco STX/Algonquin (f)	Algonquin @ Lambertville, NJ (g)	Columbia (Maumee/Downington) (h)	Tennessee 6 to 6 Dracut (i)	Total (j) = Sum[(c) : (i)]
	2017-2018 Marketer Reconciliation									
	Month of activity									
(23)	Nov-17	30	195,000	255,000	285,000	121,320	69,090	72,210	7,200	1,004,820
(24)	Dec-17	31	201,500	263,469	294,500	125,333	72,447	76,570	7,192	1,041,011
(25)	Jan-18	31	201,500	263,500	294,500	125,364	71,703	73,315	7,099	1,036,981
(26)	Feb-18	29	182,000	238,000	266,000	113,232	63,952	63,532	6,412	933,128
(27)	Mar-18	31	201,469	263,500	294,500	125,364	71,207	70,959	7,006	1,034,005
(28)	Apr-18	30	196,778	257,327	287,617	122,394	70,165	69,269	7,040	1,010,590
(29)	May-18	31	212,939	262,415	282,100	126,418	72,695	72,106	6,913	1,035,586
(30)	Jun-18	30	195,000	255,000	285,000	121,320	69,960	71,610	6,630	1,004,520
(31)	Jul-18	31	201,469	263,500	294,500	125,333	73,966	79,236	6,820	1,044,824
(32)	Aug-18	31	201,500	263,500	294,500	125,364	73,470	76,198	6,665	1,041,197
(33)	Sep-18	30	195,000	255,000	285,000	121,320	69,540	67,740	6,480	1,000,080
(34)	Oct-18	31	201,469	263,500	294,469	125,364	71,951	72,230	6,851	1,035,834
(35)	Total		2,385,624	3,103,711	3,457,686	1,478,126	850,146	864,975	82,308	12,222,576
	Approved									
(36)	System Average		$0.6168	$0.6168	$0.6168	$0.6168	$0.6168	$0.6168	$0.6168	
(37)	Path		$0.7630	$0.8717	$1.0067	$1.1166	$0.3507	$0.3698	$1.7441	
(38)	Credit/Surcharge		($0.1462)	($0.2549)	($0.3899)	($0.4998)	$0.2661	$0.2470	($1.1273)	
	Revised									
(39)	System Average		$0.6142	$0.6142	$0.6142	$0.6142	$0.6142	$0.6142	$0.6142	
(40)	Path		$0.7621	$0.8709	$1.0067	$1.1157	$0.3507	$0.3621	$1.7441	
(41)	Credit/Surcharge		($0.1479)	($0.2567)	($0.3925)	($0.5015)	$0.2635	$0.2521	($1.1299)	
(42)	Variance_Approved Surcharge/Credit vs. Revised Surch		($0.0017)	($0.0018)	($0.0026)	($0.0017)	($0.0026)	$0.0051	($0.0026)	
(43)	Annual MDCQ		2,385,624	3,103,711	3,457,686	1,478,126	850,146	864,975	82,308	12,222,576
(44)	Updated 2017-18 Marketer Reconciliation Adjustment		($4,056)	($5,587)	($8,990)	($2,513)	($2,210)	$4,411	($214)	($19,158)
(45)	Under/(Over)-collections 2017-18 Marketer Reconciliation[1]									($6,537)
(46)	Total 2017-18 amount subject to Marketer Reconciliation									($25,695)
(47)	Already Collected from Marketers[2]									($25,892)
(48)	Under/(Over)-collections for 2018-19 Marketer Reconciliation									$197
(49)	Total 2017-18 & 2018-19 Marketer Reconciliation Surcharged to Marketers									$4,641
(50)	Total 2017-18 & 2018-19 Marketer Reconciliation_Credit to Firm Sales Customers									**($4,641)**

(36) & (37): Dkt 4719 EDA-4
(38): Line (36) - Line (37)
(41): Line (39) - Line (40)
(42): Line (41) - Line (38)
(43): Line (35)
(44): Line (42) x Line (43)
(46): Line (44) + Line (45)
(48): Line (46) - Line (47)
(49): Line (22) + Line (48)
(50): - Line (49)

[1] Docket No. 4872 Attachment AEL-7, Line 48, updated to reflect actual collections for Jul. 2018-Oct. 2018.

[2] Nov. 2018 - July 2019 as reflected in GCR Monthly Deferred Report filed on August 20, 2019 Schedule 2, Line 78. Aug. 2019 - Oct. 2019 are projected collections.

Testimony of
Theodore Poe, Jr.

DIRECT TESTIMONY

OF

THEODORE POE, JR.

September 3, 2019

Table of Contents

I. Introduction

Q. Please state your name and business address.

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

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

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

Q. Please summarize your educational background and professional experience.

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science degree in Geology. From 1981 to 1989, I worked as a Research Associate with Jensen Associates, Inc. of Boston, where I was responsible for developing a variety of computer-forecasting models to analyze natural gas supply and demand for interstate pipeline and local gas distribution companies. I joined Boston Gas Company in 1989, where I was responsible for modeling and forecasting customers' natural gas resource requirements and managing the resource planning process. In 1998-99, I assumed the same responsibilities for Essex Gas Company and Colonial Gas Company. In 2000, I assumed responsibility for modeling and forecasting the natural gas resource requirements of The Brooklyn Union Gas Company and KeySpan Gas East Corporation. In 2008, I assumed responsibility for modeling and forecasting the natural gas resource requirements of the Company, as well as Niagara Mohawk Power Corporation.

Q. Are you a member of any professional organizations?

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

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

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

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

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

Q. Are you sponsoring any attachments?

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

Attachment TEP-1	National Grid RI Retail Volume Forecast 2019 vs. 2018 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2019 vs. 2018 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2019 vs. 2018 Forecast
Attachment TEP-4	National Grid RI Retail Volume Forecast by Rate Class 2019 vs. 2018 Forecast

Attachment TEP-5	National Grid RI Retail Meter Count Forecast by Rate Class 2019 vs. 2018 Forecast

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

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

II. Summary of Retail and Wholesale Natural Gas Forecasts

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

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

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

For the Company's forecast, "retail" refers to gas delivered and metered at customers' burner tips, and "wholesale" refers to gas received and metered flowing into the Company's distribution system. The Company's retail forecast is prepared through econometric and statistical modeling of both customer count (meter count) and use-per-customer. This process is documented in greater detail in the Company's Gas Long-Range Resource and Requirements Plan for the Forecast Period 2019/20 through 2023/24 dated July 2, 2019 that was filed with the Rhode Island Division of Public Utilities and Carriers (Long Range Plan). Billing data is modeled at the rate class level and further sub-categorized as sales or transportation (either capacity-eligible or capacity-exempt). The Company's volume forecast is the product of meter count and use-per-customer at the rate class level. The retail forecast takes into account the impact of the Company's energy efficiency programs.

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

III. The 2019 Gas Forecast

Q. What is the role of the 2019 gas forecast in the Gas Cost Recovery proceeding?

A. With 68 percent of the Company’s wholesale deliveries occurring between the months of November through March, as set forth in the pre-filed joint direct testimony of Company witnesses Elizabeth D. Arangio and Samara A. Jaffe on Attachment EDA/SAJ-2, Page 1, the Company’s gas resource portfolio and gas supply purchase planning are designed to address its customers’ needs during the winter peak period and throughout the year. Each year, the Company constructs its gas forecast by accounting for the most recent heating season’s actual customer usage patterns. 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 Gas Cost Recovery costs. Second, the Company’s forecasts of design winter requirements form the basis for the Company’s allocation of fixed costs between High Load Factor and Low Load Factor service classifications. Third, forecasts of total annual sales and throughput requirements provide the denominators used in the Company’s computation of applicable charges on a dollars per therm basis. The Company’s forecasts of future gas service requirements also serve as important indicators of the need for additional capacity to ensure the reliability of 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 its assessment of the economics of alternative gas supply resources.

Q. How do the forecasted sales requirements for 2019/20 compare to the prior retail forecast for 2018/19?

A. A comparison of the Company's 2018 gas forecast of firm retail volumes for the period November 2018 through October 2019 and its current firm retail volume forecast for November 2019 through October 2020 is shown in Table 1, below.

Table 1

	2018/19 Forecasted Volume (MMBtu)	2019/20 Forecasted Volume (MMBtu)
Residential Sales	19,982,738	20,300,786
C&I Sales	6,672,101	7,256,274
Total Sales	26,654,839	27,557,060
C&I Transportation	12,874,013	14,095,997
Total	39,528,852	41,653,037

Source: Attachment TEP-1

In summary, the 2019/20 forecast for Total Sales and Commercial and Industrial (C&I) Transportation customer volumes shows a 4.9 percent increase over the 2018/19 forecast, with Total Sales increasing by 3.3 percent and C&I Transportation increasing by 8.2 percent.

Attachment TEP-1 contains tables showing planning year[1] (PY) volumes from PY 2011 through PY 2027 for the Company's current (2019) volume forecast and last year's (2018) forecast. The data is presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts are provided in Attachment TEP-1 for visual comparison. The primary change in the forecast from 2018 to 2019 is an increase in C&I Sales and C&I Firm Transportation volumes. The five-year per annum growth rate in volumes (excluding Other) from PY 2019 to PY 2024 is 1.2 percent, which is greater than the 0.3 percent per annum growth rate forecasted last year.

Attachment TEP-2 contains tables from PY 2011 through PY 2027 showing the Company's current (2019) meter count forecast and last year's (2018) forecast. The data is presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts are provided in Attachment TEP-2 for visual comparison. The primary changes in the

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

meter count forecast from 2018 to 2019 are increases in the forecasted growth rates of Residential Heating and C&I Sales customers. The five-year per annum growth rate in meter count (excluding Other) from PY 2019 to PY 2024 is 1.1 percent, which is greater than the 0.7 percent per annum growth rate forecasted last year.

On a wholesale basis (<u>see</u> Attachment EDA/SAJ-2, Page 1), the Company forecasts sales volumes to be 28,179,000 MMBtu[2] for the period November 2019 through October 2020. Comparatively, in the Company's previous wholesale forecast for November 2018 through October 2019, as filed in Docket No. 4872, the sales volume was projected to be 29,432,358 MMBtu. Wholesale sales volume is projected to decrease 4.3 percent.

Attachment TEP-3 contains tables for calendar year economic data from 1990 through 2027 for the Company's current (2019) forecast and last year's (2018) forecast. The data is presented for the following key indicators: Natural Gas Residential Price, Residential No. 2 Oil Price, the Gas-to-Oil Price Ratio, Rhode Island Gross Domestic Product, Households, and Non-Farm Employment. Charts are provided in Attachment TEP-3 for visual comparison. The overall 2019 economic forecast shows little change from the 2018 economic forecast, with lower growth rates in natural gas and oil prices and a stronger growth rate in state GDP from PY 2019 through PY 2024.

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

Q. Have there been any changes to the forecasted sales requirements for 2019/20 as compared to the Company's Long Range Plan?

A. Yes. In preparation of this instant filing, the Company found that it had made a calculation error in the inclusion of the volumes associated with certain customers incremental to its econometric forecast. In the Long Range Plan, the Company's forecast of Sales and Transportation volumes for 2019/20 (see Table 2 below) was approximately 300,000 MMBtu or approximately 0.8 percent greater than the volumes presented in Table 1 above. The forecast presented in the instant filing reflects that correction.

Table 2

	2019/20 Forecasted Volume (MMBtu)
Residential Sales	20,313,371
C&I Sales	7,412,069
Total Sales	27,725,440
C&I Transportation	14,240,243
Total	41,965,683

Q. How has the Company accounted for the effects of weather variations in the historic data inputs to its 2019 gas forecast?

A. In preparing the 2019 gas forecast, the Company used its monthly customer billing data (volume and number of customers) for the period August 2010 through February 2019 to forecast the number of customers and use-per-customer for each of the rate groups the Company analyzes. The Company obtained the historical monthly use-per-customer values by dividing volume of total billed therms for each month by the number of customers for the month. Weather, particularly heating degree days, plays the dominant role in modeling the use-per-customer behavior of the Company's customers under the wide range of weather observed in the historical period. The Company's forecast then applies its normalized heating degree days as the basis of its forecast of use-per-customer under normal weather conditions.

Q. How did the Company's 2018/19 forecast compare to the actual billings weather normalized for the same period?

A. According to the Company's most recent analysis where it normalized its actual billing data for June 2018 through May 2019, actual normalized Firm Sales customers plus C&I Transportation customers totaled 39,960,188 MMBtu. In the Company's 2018 Gas Cost Recovery filing (Docket 4872), the Company's normalized forecast volume for November 2018 through October 2019 was 39,528,852 MMBtu, as set forth in Table 1, above. Actual normalized sales were 1.1 percent higher than forecast.

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

A. The Company develops appropriate design day and design year planning standards to design a least-cost, reliable supply portfolio for its forecast period. The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. The Company maintains a design year standard for planning purposes to identify the amount of seasonal supplies of natural gas that will be required to provide continuous service under all reasonable weather conditions. The Company establishes its design standards using a three-step process. First, the Company performs statistical analyses of the coldest days and of the annual degree days recorded over a historical period. Second, the Company conducts cost-benefit analyses to evaluate the cost of maintaining the resources necessary to meet design-level demand versus the cost to customers of experiencing service curtailments. Third, the Company identifies design standards that would maintain reliability at the lowest cost.

Q. Does this conclude your testimony?

A. Yes.

Attachments of Theodore Poe, Jr.

Attachment TEP-1	National Grid RI Retail Volume Forecast 2019 vs. 2018 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2019 vs. 2018 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2019 vs. 2018 Forecast
Attachment TEP-4	National Grid RI Retail Volume Forecast by Rate Class 2019 vs. 2018 Forecast
Attachment TEP-5	National Grid RI Retail Meter Count Forecast by Rate Class 2019 vs. 2018 Forecast

Attachment TEP-1

Attachment TEP-1

National Grid RI Retail Volume Forecast

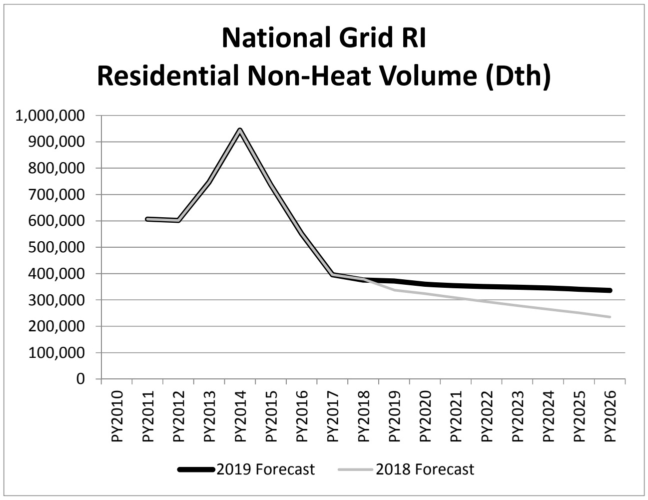
2019 vs 2018 Forecast

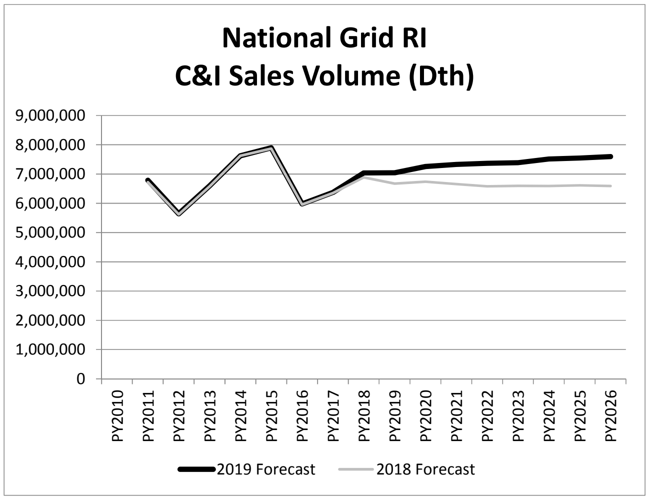
2019 National Grid RI Volume Forecast (Dth) Chart III-B-1
Planning Year (Nov-Oct) Page 1 of 2

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,785,948	7,680,544	2,569,158	35,380,289	2,205,459	37,585,748
PY2012	601,399	14,783,757	5,641,385	7,610,425	2,334,007	30,970,973	2,175,385	33,146,358
PY2013	746,890	17,315,788	6,597,004	8,278,483	3,062,257	36,000,422	1,985,726	37,986,148
PY2014	944,174	19,573,872	7,624,248	8,563,673	3,585,382	40,291,350	1,734,538	42,025,888
PY2015	736,952	20,389,772	7,897,957	9,416,525	3,745,573	42,186,778	1,736,206	43,922,984
PY2016	551,336	16,675,346	5,978,805	8,656,943	3,646,308	35,508,738	1,769,137	37,277,875
PY2017	395,746	18,594,052	6,371,076	8,698,747	4,058,521	38,118,143	1,727,212	39,845,355
PY2018	375,420	19,942,385	7,039,693	9,022,578	4,335,718	40,715,795	1,782,779	42,498,574
PY2019	371,670	19,674,485	7,043,065	9,100,758	4,596,876	40,786,854	1,855,857	42,642,712
PY2020	359,772	19,941,015	7,256,274	9,391,677	4,704,300	41,653,037	1,889,959	43,542,996
PY2021	354,474	20,078,627	7,328,416	9,450,501	4,704,220	41,916,238	1,891,966	43,808,204
PY2022	350,941	20,337,068	7,367,641	9,495,708	4,719,281	42,270,639	1,898,378	44,169,017
PY2023	347,655	20,593,684	7,389,007	9,663,594	4,729,763	42,723,702	1,905,470	44,629,172
PY2024	345,785	20,992,308	7,516,469	9,758,175	4,755,377	43,368,114	1,914,636	45,282,750
PY2025	340,294	21,113,260	7,548,063	9,763,110	4,754,715	43,519,441	1,918,349	45,437,790
PY2026	335,883	21,368,315	7,599,371	9,791,351	4,780,638	43,875,558	1,926,862	45,802,420
PY2027	331,273	21,621,960	7,654,444	9,822,601	4,809,220	44,239,498	1,935,888	46,175,385
PY24/PY19	-1.4%	1.3%	1.3%	1.4%	0.7%	1.2%	0.6%	1.2%

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

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,723,757	7,680,544	2,569,158	35,318,097	2,205,233	37,523,331
PY2012	601,399	14,783,757	5,621,627	7,610,425	2,334,007	30,951,215	2,169,374	33,120,589
PY2013	746,888	17,315,788	6,580,974	8,278,483	3,062,257	35,984,391	1,985,725	37,970,115
PY2014	944,135	19,573,872	7,622,602	8,563,673	3,585,382	40,289,664	1,734,538	42,024,202
PY2015	736,897	20,389,733	7,868,314	9,416,525	3,745,573	42,157,042	1,736,206	43,893,248
PY2016	551,234	16,675,190	5,957,637	8,656,943	3,646,308	35,487,311	1,769,137	37,256,449
PY2017	395,530	18,593,539	6,351,832	8,709,202	4,050,589	38,100,691	1,727,212	39,827,903
PY2018	378,646	19,891,785	6,884,562	8,872,850	4,315,187	40,343,031	1,703,545	42,046,575
PY2019	337,218	19,645,520	6,672,101	8,786,738	4,245,454	39,687,032	1,587,493	41,274,524
PY2020	324,087	19,872,551	6,740,466	8,787,353	4,310,429	40,034,886	1,587,999	41,622,886
PY2021	307,966	20,033,440	6,654,173	8,683,991	4,319,218	39,998,787	1,628,287	41,627,075
PY2022	293,738	20,039,687	6,578,993	8,680,907	4,330,601	39,923,925	1,636,147	41,560,072
PY2023	277,865	20,255,792	6,595,995	8,644,859	4,359,023	40,133,535	1,637,310	41,770,845
PY2024	265,337	20,524,909	6,590,653	8,652,037	4,373,869	40,406,805	1,647,715	42,054,520
PY2025	250,974	20,669,989	6,612,811	8,599,977	4,393,900	40,527,651	1,642,966	42,170,616
PY2026	235,326	20,752,635	6,589,457	8,595,976	4,416,334	40,589,728	1,633,143	42,222,870
PY2027	224,465	20,870,341	6,616,182	8,584,867	4,447,037	40,742,892	1,631,292	42,374,184
PY24/PY19	-4.7%	0.9%	-0.2%	-0.3%	0.6%	0.4%	0.7%	0.4%


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
2019 Forecast
2018 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
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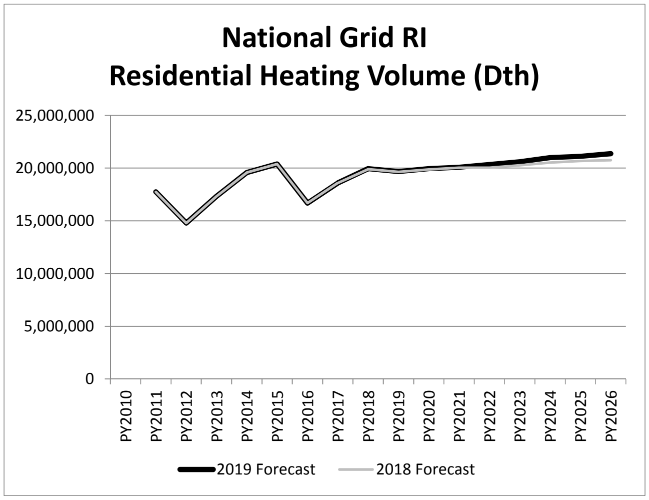
PY2025
PY2026
2019 Forecast
2018 Forecast


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
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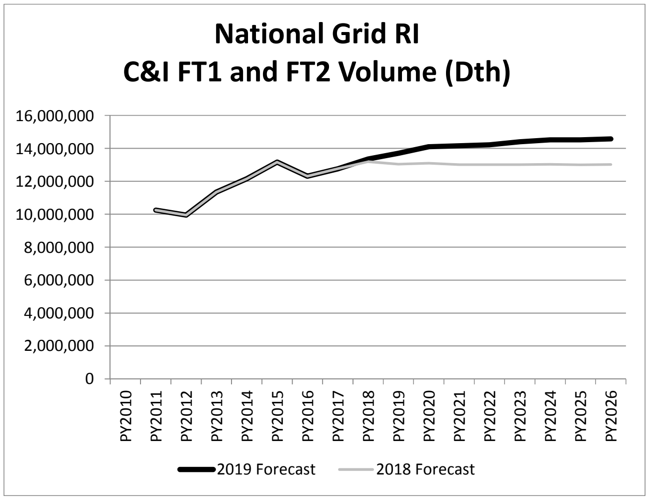
PY2019
PY2020
PY2021
PY2022
PY2023
PY2024
PY2025
PY2026
2019 Forecast
2018 Forecast


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
2019 Forecast
2018 Forecast

Attachment TEP-2

Attachment TEP-2

National Grid RI Retail Meter Count Forecast

2019 vs 2018 Forecast

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

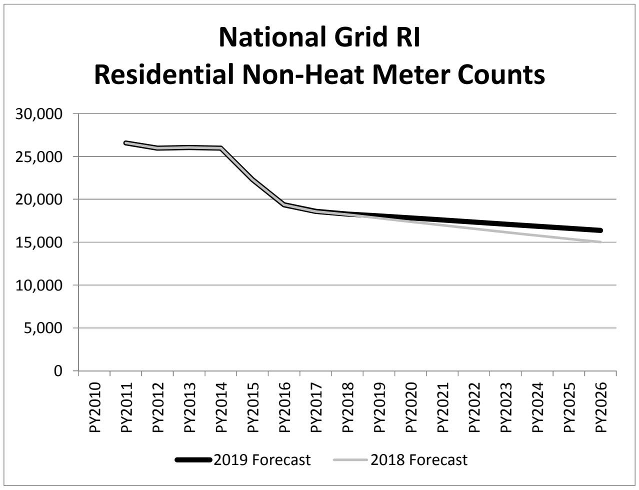
Chart III-B-2
Page 1 of 2

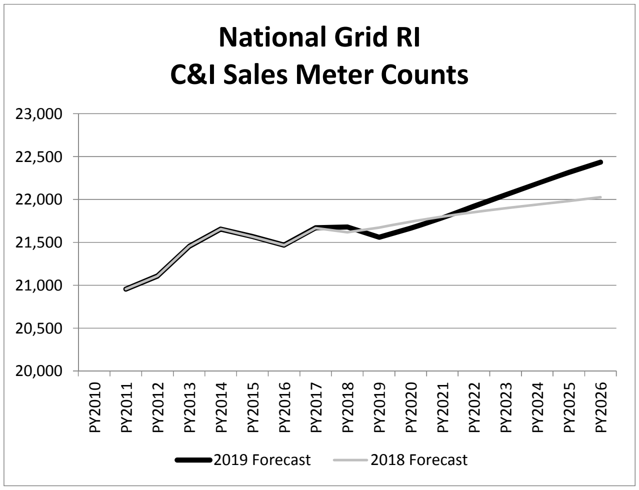
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,954	747	1,244	245,929	50	245,979
PY2012	25,955	200,463	21,108	734	1,412	249,672	49	249,721
PY2013	26,042	204,520	21,453	721	1,613	254,349	43	254,392
PY2014	25,958	206,567	21,654	699	1,621	256,499	39	256,538
PY2015	22,313	212,899	21,568	684	1,840	259,304	35	259,339
PY2016	19,351	218,312	21,468	674	2,131	261,936	34	261,970
PY2017	18,589	222,114	21,669	636	2,297	265,305	35	265,340
PY2018	18,280	225,136	21,679	624	2,375	268,094	35	268,129
PY2019	18,059	226,499	21,559	601	2,467	269,185	35	269,220
PY2020	17,816	229,543	21,666	606	2,479	272,110	35	272,145
PY2021	17,574	232,610	21,784	613	2,493	275,074	35	275,109
PY2022	17,332	235,549	21,921	619	2,510	277,931	35	277,966
PY2023	17,090	238,549	22,053	624	2,525	280,841	35	280,876
PY2024	16,847	241,525	22,185	630	2,540	283,727	35	283,762
PY2025	16,605	244,499	22,314	633	2,555	286,606	35	286,641
PY2026	16,363	247,462	22,434	635	2,568	289,462	36	289,498
PY2027	16,120	250,404	22,550	639	2,583	292,296	36	292,332
PY24/PY19	-1.4%	1.3%	0.6%	0.9%	0.6%	1.1%	0.0%	1.1%

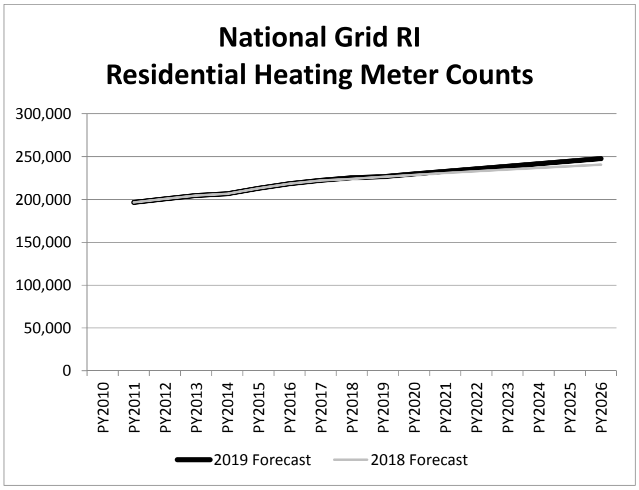
2018 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

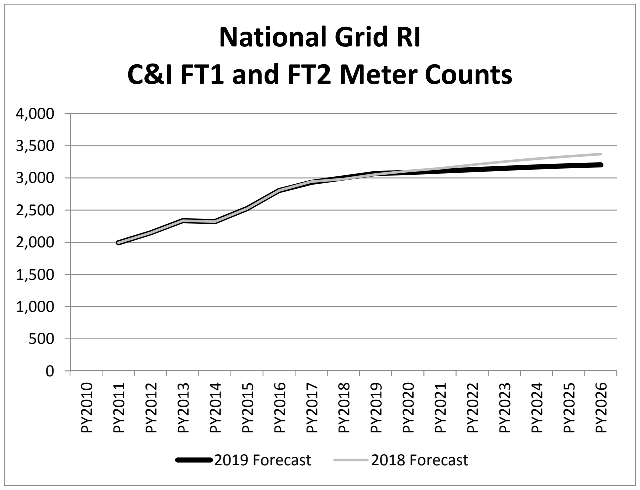
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,954	747	1,244	245,929	50	245,979
PY2012	25,955	200,463	21,108	734	1,412	249,672	50	249,722
PY2013	26,042	204,520	21,453	721	1,613	254,349	46	254,395
PY2014	25,957	206,567	21,654	699	1,621	256,498	41	256,539
PY2015	22,311	212,896	21,565	684	1,841	259,297	36	259,333
PY2016	19,348	218,305	21,465	674	2,132	261,924	38	261,962
PY2017	18,572	222,014	21,666	644	2,298	265,194	38	265,232
PY2018	18,214	223,810	21,617	634	2,348	266,623	36	266,659
PY2019	17,796	226,216	21,672	629	2,424	268,737	36	268,773
PY2020	17,375	228,517	21,738	627	2,479	270,736	36	270,772
PY2021	16,960	230,711	21,800	628	2,521	272,620	36	272,656
PY2022	16,552	232,804	21,853	628	2,575	274,412	39	274,451
PY2023	16,154	234,808	21,896	625	2,627	276,110	41	276,151
PY2024	15,763	236,732	21,939	625	2,673	277,732	41	277,773
PY2025	15,383	238,582	21,980	622	2,714	279,281	41	279,322
PY2026	15,010	240,366	22,025	622	2,749	280,772	41	280,813
PY2027	14,646	242,089	22,069	622	2,779	282,205	41	282,246
PY24/PY19	-2.4%	0.9%	0.2%	-0.1%	2.0%	0.7%	2.6%	0.7%

Chart III-B-2
Page 2 of 2









Attachment TEP-3

Attachment TEP-3

National Grid RI Economic Forecast

2019 vs 2018 Forecast

2019 National Grid RI Economic Data
(Prices in 2018 $/Dth)

Chart III-B-3
Page 1 of 3

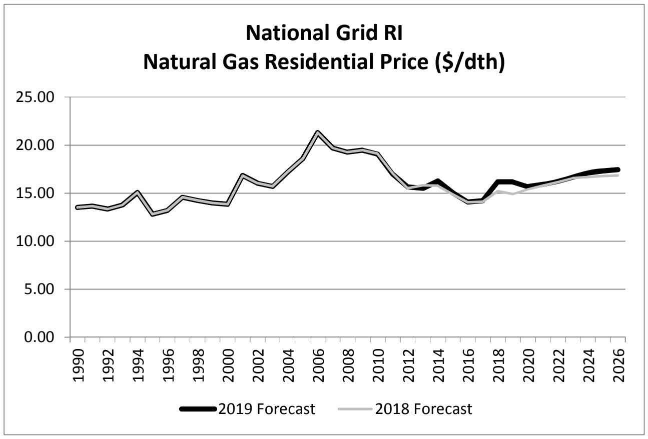
	NGPRCR	OILPRCR	*GORR*	GDP	HH	EMPL
Year	Natural Gas Residential Price	No 2 Distillate Residential Price by All Sellers	*Residential Gas-to-Oil Price Ratio*	GDP (2009 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	*13.50*	*14.60*	*0.92*	*35615.834*	*377.381*	*454.225*
1991	*13.62*	*13.32*	*1.02*	*34371.872*	*380.898*	*424.283*
1992	*13.33*	*11.69*	*1.14*	*35062.829*	*383.703*	*424.050*
1993	*13.77*	*11.20*	*1.23*	*35716.351*	*387.380*	*429.925*
1994	*15.06*	*10.61*	*1.42*	*35826.302*	*391.398*	*434.208*
1995	*12.79*	*10.30*	*1.24*	*36504.778*	*395.112*	*439.125*
1996	*13.18*	*11.25*	*1.17*	*36926.285*	*400.848*	*440.767*
1997	*14.58*	*11.19*	*1.30*	*38989.000*	*405.502*	*450.058*
1998	*14.24*	*9.70*	*1.47*	*40360.000*	*410.961*	*457.950*
1999	*13.96*	*9.05*	*1.54*	*41651.000*	*411.187*	*465.500*
2000	*13.82*	*12.91*	*1.07*	43474.392	410.048	476.899
2001	*16.81*	*12.61*	*1.33*	44386.037	407.448	478.570
2002	*16.03*	*11.17*	*1.43*	45877.152	410.055	479.443
2003	*15.68*	*13.33*	*1.18*	47804.229	410.574	484.272
2004	*17.18*	*14.12*	*1.22*	49761.660	412.054	488.480
2005	*18.56*	*18.01*	*1.03*	50378.278	411.331	491.112
2006	*21.29*	*21.17*	*1.01*	51303.695	411.259	492.981
2007	*19.70*	*22.08*	*0.89*	49842.521	411.345	492.007
2008	*19.25*	*27.64*	*0.70*	48263.470	414.018	481.090
2009	*19.45*	*19.50*	*1.00*	47707.923	413.979	459.442
2010	19.07	24.28	*0.79*	48801.485	414.266	457.998
2011	16.97	30.08	*0.56*	48425.183	417.092	460.503
2012	15.62	32.03	*0.49*	48630.473	421.162	465.460
2013	15.48	31.46	*0.49*	48814.886	424.749	471.528
2014	16.24	30.31	*0.54*	49217.202	427.946	478.676
2015	15.04	21.17	*0.71*	50174.493	428.074	485.246
2016	14.05	16.80	*0.84*	50405.738	427.378	489.746
2017	14.18	19.36	*0.73*	51192.420	425.779	494.437
2018	16.16	21.44	*0.75*	52718.707	422.397	501.393
2019	16.17	20.28	*0.80*	54456.379	424.336	507.423
2020	15.66	20.82	*0.75*	55401.132	426.192	509.788
2021	15.90	21.24	*0.75*	56891.471	427.522	509.237
2022	16.23	21.56	*0.75*	58647.133	429.319	512.494
2023	16.65	22.20	*0.75*	60157.756	430.927	515.228
2024	17.11	23.23	*0.74*	61647.141	432.406	517.538
2025	17.29	23.81	*0.73*	63012.853	433.870	519.685
2026	17.42	24.21	*0.72*	64358.098	435.117	521.780
2027	17.50	24.86	*0.70*	65762.272	436.111	523.848
PY24/PY19	1.1%	2.8%	-1.6%	2.5%	0.4%	0.4%

2018 National Grid RI Economic Data
(Prices in 2017 $/Dth)

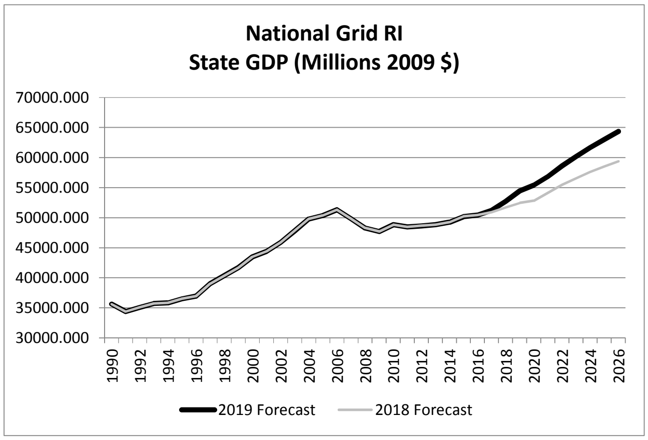
Chart III-B-3
Page 2 of 3

	NGPRCR	OILPRCR	GORR	GDP	HH	EMPL
Year	Natural Gas Residential Price	No 2 Distillate Residential Price by All Sellers	Residential Gas-to-Oil Price Ratio	GDP (2009 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	13.50	14.60	*0.92*	35615.834	377.381	454.225
1991	13.62	13.32	*1.02*	34371.872	380.898	424.283
1992	13.33	11.69	*1.14*	35062.829	383.703	424.050
1993	13.77	11.20	*1.23*	35716.351	387.380	429.925
1994	15.06	10.61	*1.42*	35826.302	391.398	434.208
1995	12.79	10.30	*1.24*	36504.778	395.112	439.125
1996	13.18	11.25	*1.17*	36926.285	400.848	440.767
1997	14.58	11.19	*1.30*	38989.000	405.502	450.058
1998	14.24	9.70	*1.47*	40360.000	410.961	457.950
1999	13.96	9.05	*1.54*	41651.000	411.187	465.500
2000	13.82	12.91	*1.07*	43476.000	410.045	476.908
2001	16.81	12.61	*1.33*	44388.000	407.452	478.508
2002	16.03	11.17	*1.43*	45881.000	410.070	479.433
2003	15.68	13.33	*1.18*	47809.000	410.589	484.275
2004	17.18	14.12	*1.22*	49763.000	412.074	488.483
2005	18.56	18.01	*1.03*	50380.000	411.353	491.125
2006	21.29	21.17	*1.01*	51304.000	411.287	492.983
2007	19.70	22.08	*0.89*	49838.000	411.381	492.017
2008	19.25	27.64	*0.70*	48262.000	414.059	481.058
2009	19.45	19.50	*1.00*	47709.000	414.002	459.350
2010	19.08	23.82	*0.80*	48803.000	414.331	458.000
2011	17.05	29.51	*0.58*	48424.000	417.189	460.517
2012	15.49	31.42	*0.49*	48631.000	421.155	465.433
2013	15.80	30.86	*0.51*	48815.000	424.831	471.500
2014	15.76	29.73	*0.53*	49269.000	427.777	478.592
2015	14.85	20.76	*0.72*	50184.000	427.961	485.142
2016	14.02	16.48	*0.85*	50433.000	428.223	490.183
2017	14.08	19.44	*0.72*	50886.712	429.631	496.433
2018	15.19	22.39	*0.68*	51677.732	431.689	500.860
2019	14.88	21.11	*0.71*	52419.286	433.525	505.014
2020	15.40	24.62	*0.63*	52796.829	435.731	505.754
2021	15.75	26.41	*0.60*	54167.415	437.651	507.058
2022	16.13	27.43	*0.59*	55500.038	439.823	511.165
2023	16.55	28.41	*0.58*	56566.757	442.090	514.149
2024	16.66	28.84	*0.58*	57597.644	444.526	516.967
2025	16.76	29.18	*0.57*	58523.715	447.122	519.349
2026	16.81	29.28	*0.57*	59360.774	449.690	521.080
2027	16.86	29.59	*0.57*	60159.199	452.090	522.573
PY24/PY19	2.3%	6.4%	-3.9%	1.9%	0.5%	0.5%

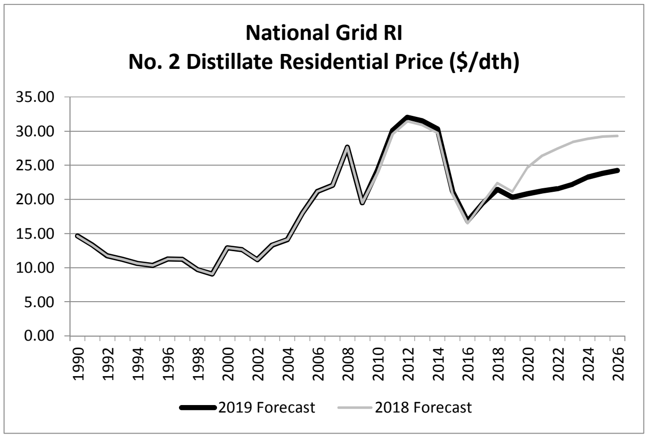
Chart III-B-3
Page 3 of 3



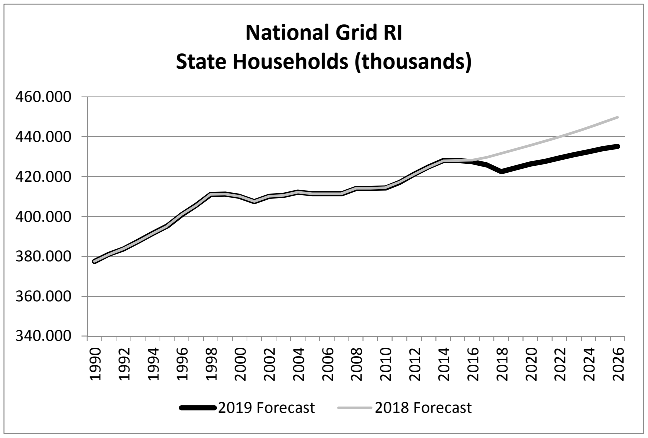
National Grid RI
Natural Gas Residential Price ($/dth)



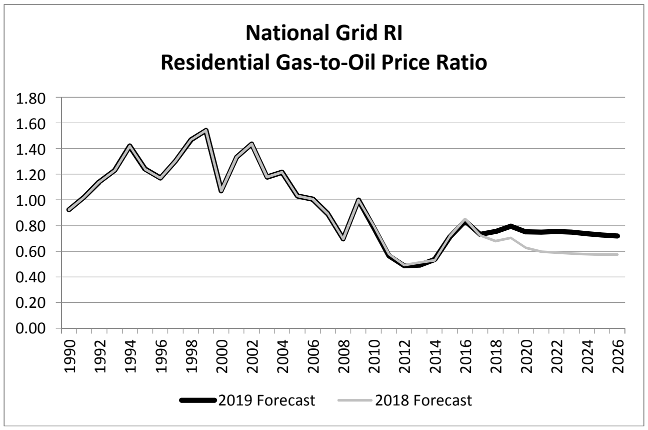
National Grid RI
State GDP (Millions 2009 $)



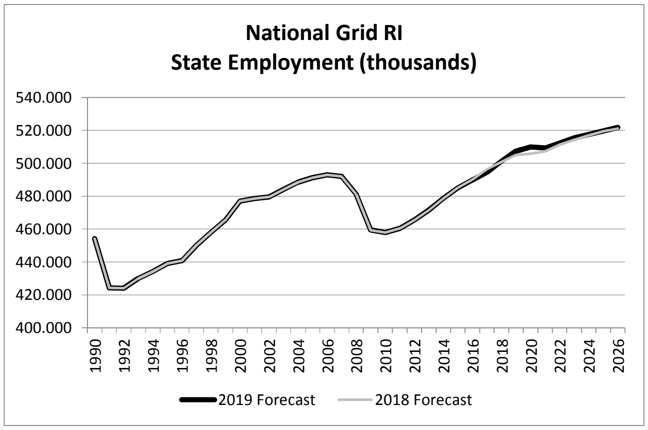
National Grid RI
No. 2 Distillate Residential Price ($/dth)



National Grid RI
State Households (thousands)



National Grid RI
Residential Gas-to-Oil Price Ratio



National Grid RI
State Employment (thousands)

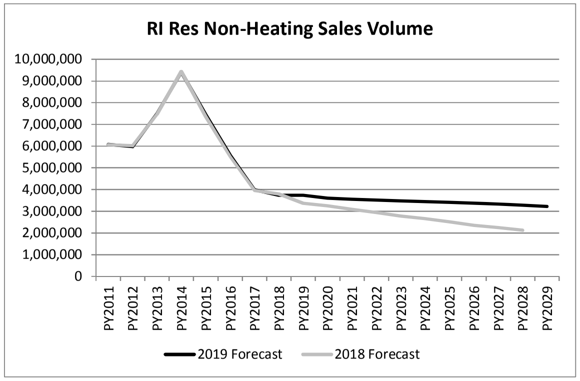
Attachment TEP-4

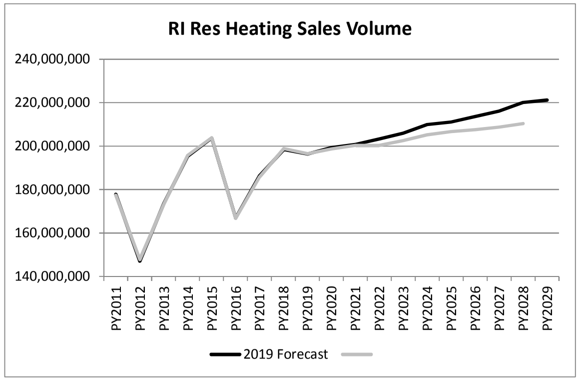
Attachment TEP-4

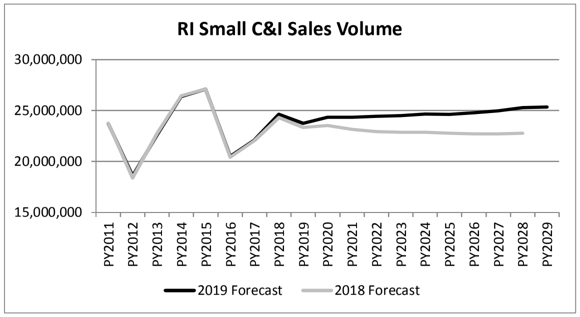
National Grid RI Retail Volume Forecast by Rate Class

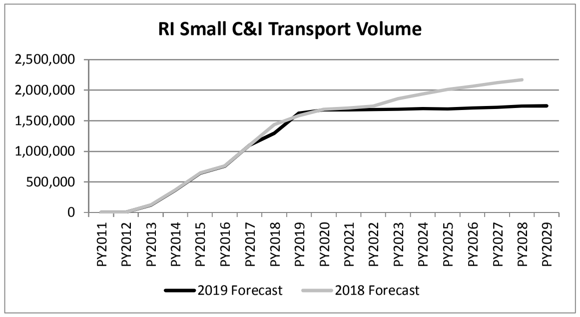
2019 vs 2018 Forecast

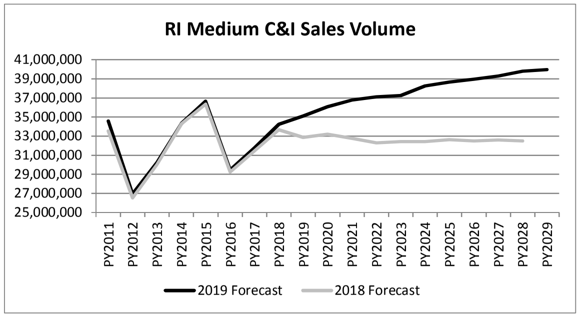
National Grid
2019 and 2018 Volume Forecasts by Rate Class
(Therms; Planning Year)

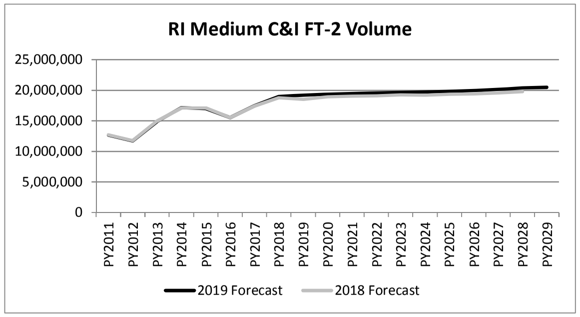

RI Res Non-Heating Sales Volume

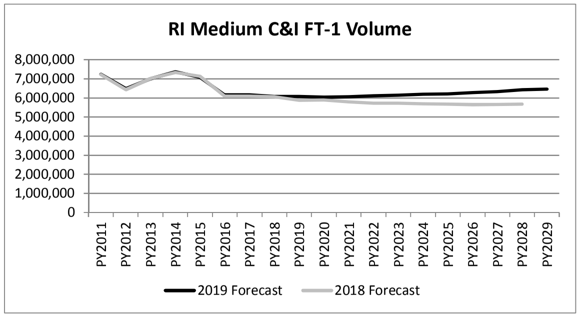

RI Res Heating Sales Volume


RI Small C&I Sales Volume

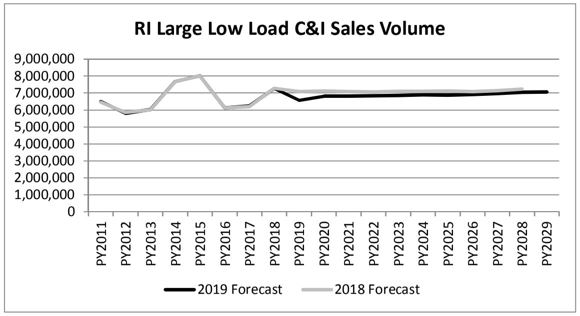

RI Small C&I Transport Volume

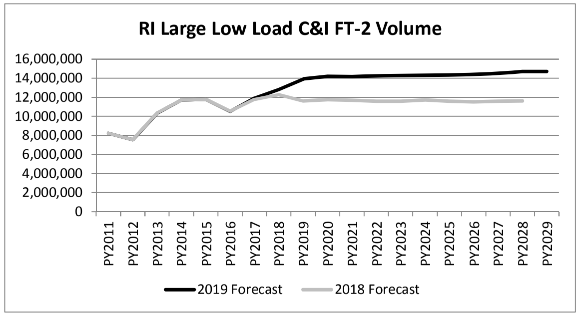

RI Medium C&I Sales Volume

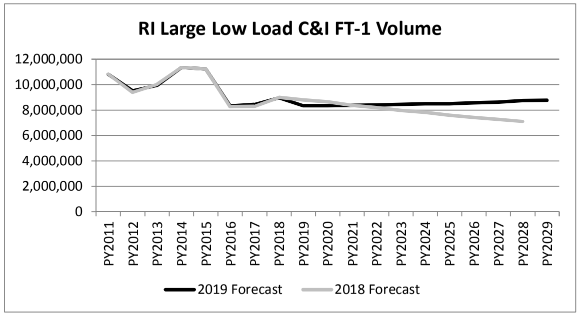

RI Medium C&I FT-2 Volume

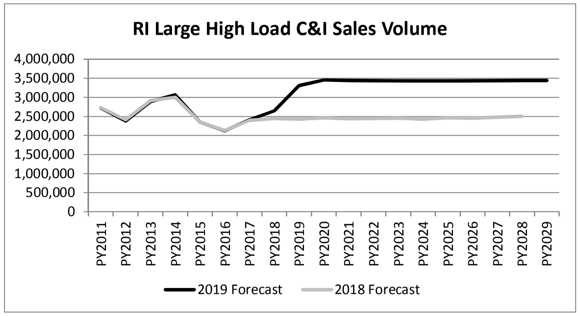

RI Medium C&I FT-1 Volume

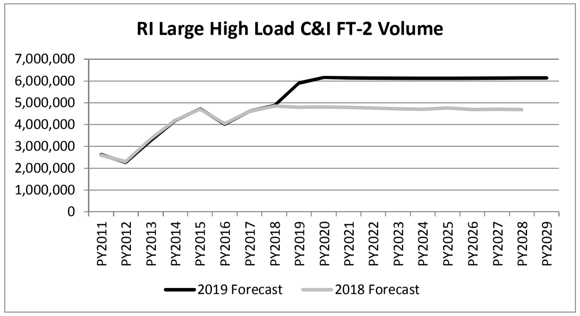
National Grid
2019 and 2018 Volume Forecasts by Rate Class
(Therms; Planning Year)

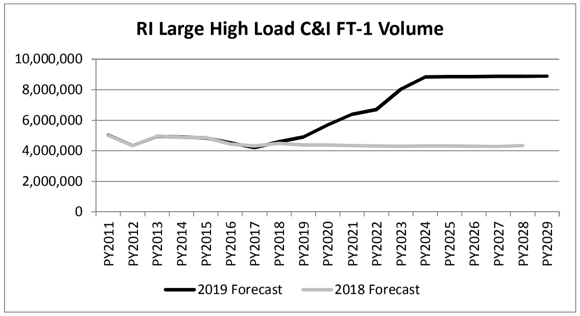

RI Large Low Load C&I Sales Volume

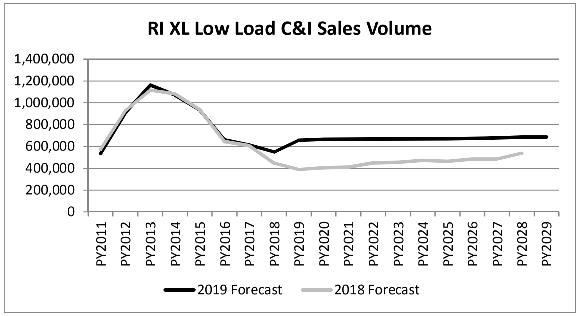

RI Large Low Load C&I FT-2 Volume

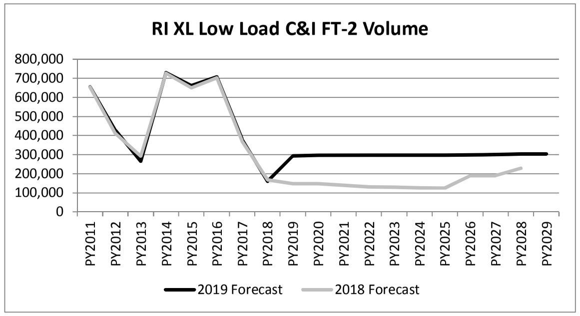

RI Large Low Load C&I FT-1 Volume

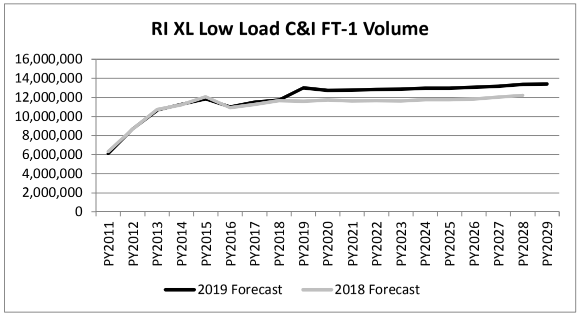

RI Large High Load C&I Sales Volume


RI Large High Load C&I FT-2 Volume

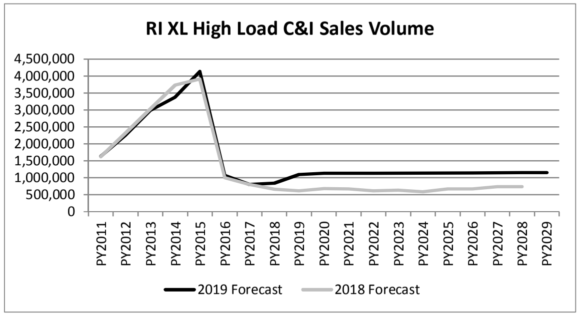

RI Large High Load C&I FT-1 Volume

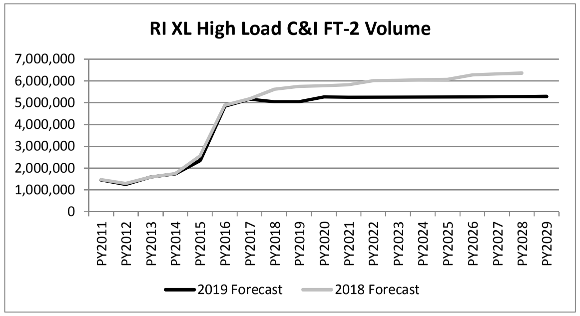

RI XL Low Load C&I Sales Volume

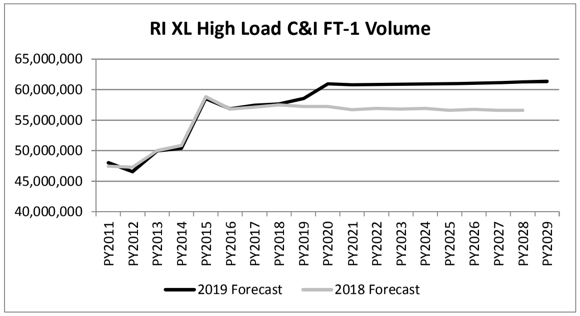

RI XL Low Load C&I FT-2 Volume

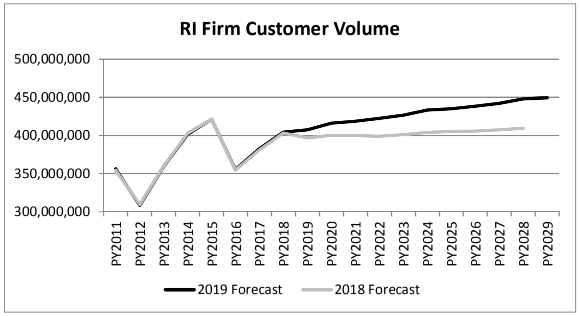

RI XL Low Load C&I FT-1 Volume

National Grid
2019 and 2018 Volume Forecasts by Rate Class
(Therms; Planning Year)


RI XL High Load C&I Sales Volume


RI XL High Load C&I FT-2 Volume


RI XL High Load C&I FT-1 Volume


RI Firm Customer Volume

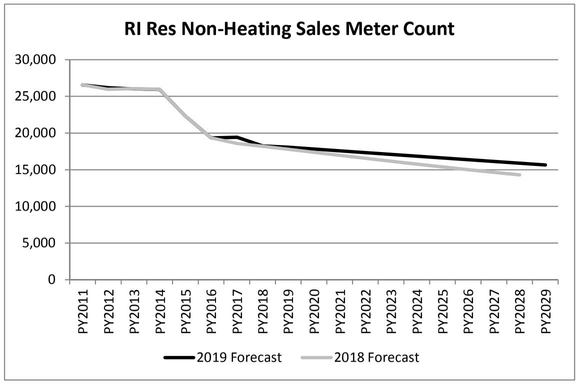
Attachment TEP-5

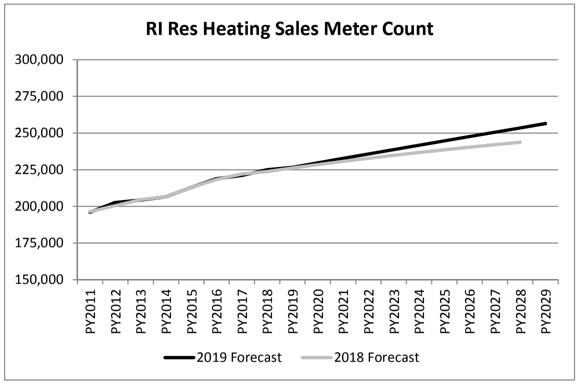
Attachment TEP-5

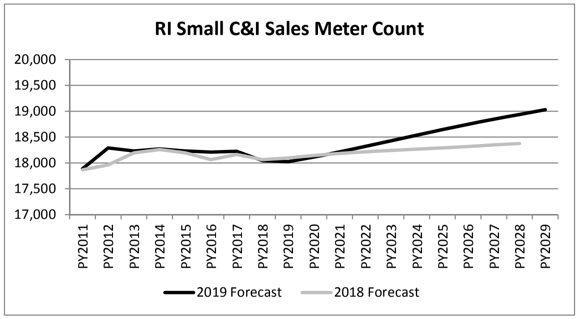
National Grid RI Retail Meter Count Forecast by Rate Class

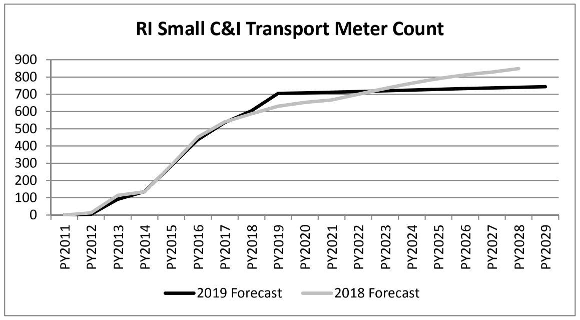
2019 vs 2018 Forecast

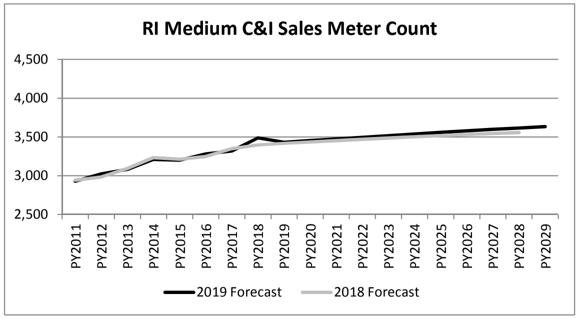
National Grid
2019 and 2018 Meter Count Forecasts by Rate Class
(end of Planning Year)

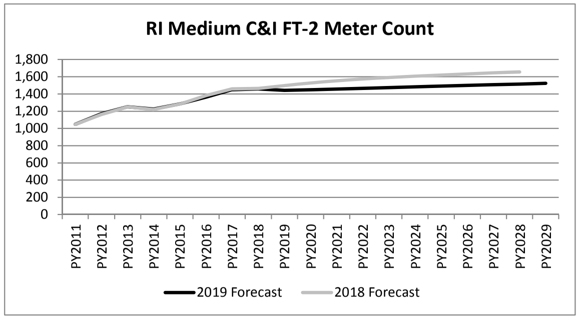


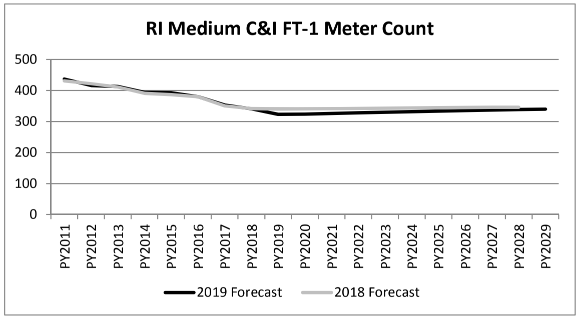




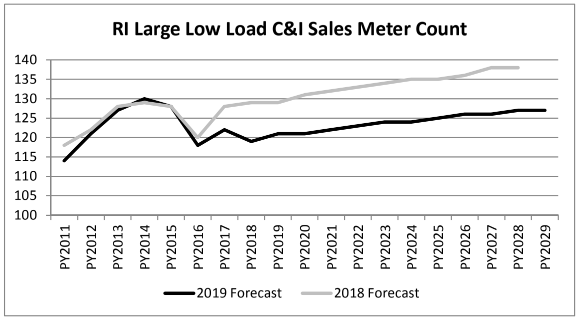


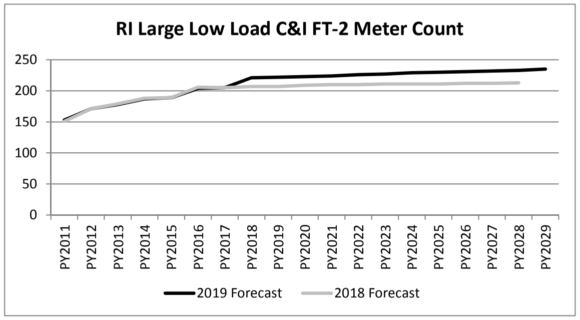


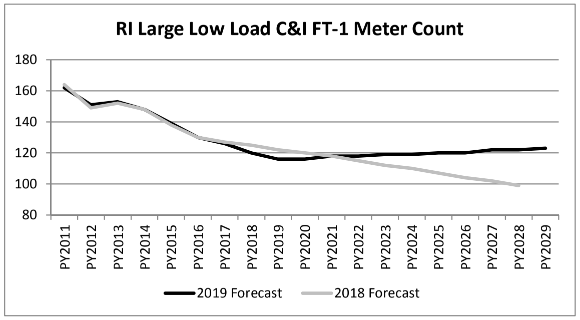


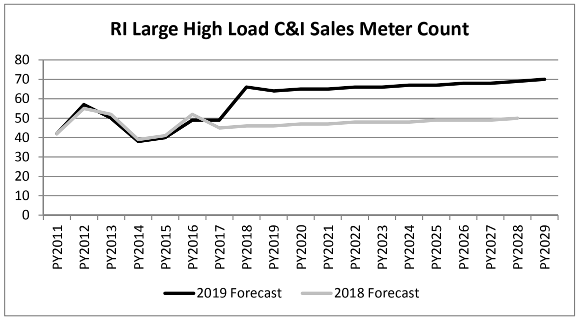


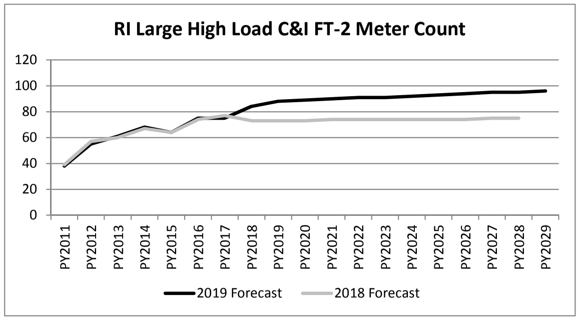
National Grid
2019 and 2018 Meter Count Forecasts by Rate Class
(end of Planning Year)

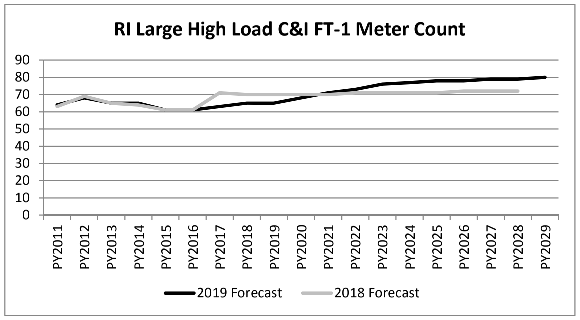

RI Large Low Load C&I Sales Meter Count

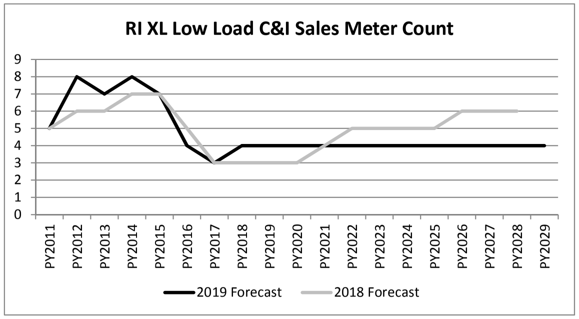

RI Large Low Load C&I FT-2 Meter Count

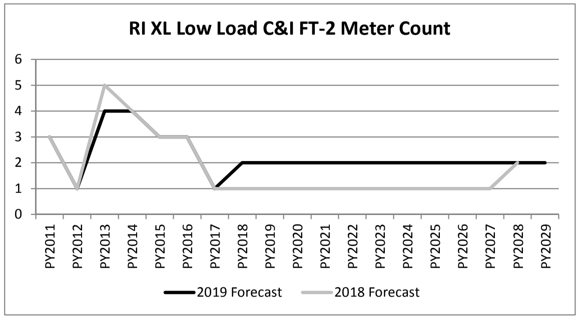

RI Large Low Load C&I FT-1 Meter Count

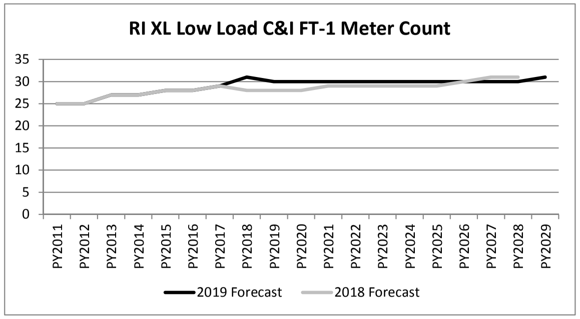

RI Large High Load C&I Sales Meter Count


RI Large High Load C&I FT-2 Meter Count

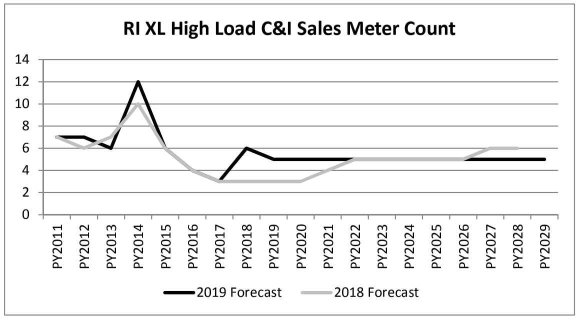

RI Large High Load C&I FT-1 Meter Count

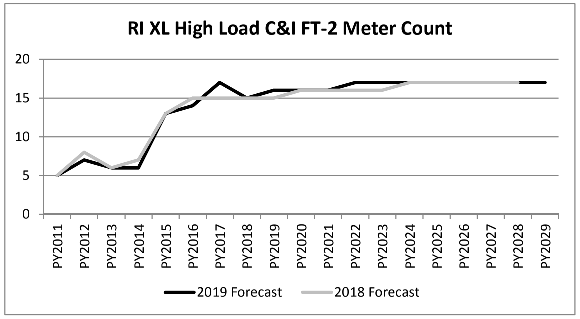

RI XL Low Load C&I Sales Meter Count


RI XL Low Load C&I FT-2 Meter Count


RI XL Low Load C&I FT-1 Meter Count

National Grid
2019 and 2018 Meter Count Forecasts by Rate Class
(end of Planning Year)


RI XL High Load C&I Sales Meter Count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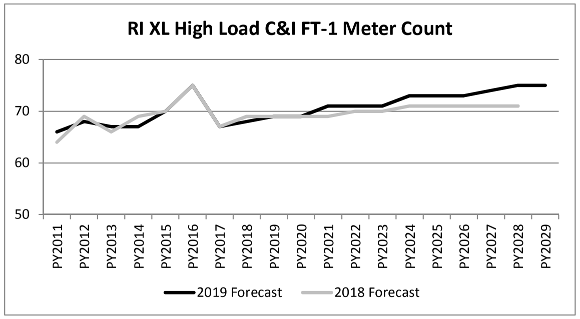
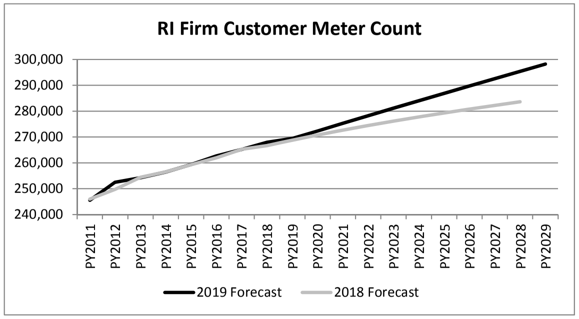

RI XL High Load C&I FT-1 Meter Count


RI Firm Customer Meter Count