nationalgrid

Thomas R. Teehan
Senior Counsel

September 4, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4346 - 2012 Gas Charge Recovery Filing

Dear Ms Massaro:

Enclosed please find ten (10) copies of the pre-filed testimony and schedules of Elizabeth D. Arangio, Ann E. Leary, and Stephen A. Mc Cauley in support of National Grid's[1] Annual Gas Cost Recovery ("GCR") filing. The proposed rates contained in this GCR filing reflect the customer class-specific factors necessary for the Company to collect sufficient revenues to recover projected gas costs for the period November 1, 2012 through October 31, 2013.

Based on the proposed GCR rate, an average residential heating customer using 922 therms per year will experience a total bill decrease related to the proposed GCR and Distribution Adjustment Charge ("DAC") rates of approximately $72 or an annual 5.6 percent decrease over the current existing rates. This decrease is comprised of an $112 decrease in GCR related costs offset by a $40 increase in the DAC related costs filed today under separate cover.

This filing also contains a Motion for Protective Treatment in accordance with Rule 1.2(g) of the Commission's Rules of Practice and Procedure and R.I.G.L. § 38-2-2(4)(B). The Company seeks protection from public disclosure of certain pricing terms contained in its FCS contract with Distrigas as well as forecast basis numbers, which are purchased subject to a contractual confidentiality agreement. Accordingly, National Grid requests that the Commission protect the price terms and basis information set forth in designated portions of Attachments EDA-2 and EDA-4. To that end, the Company has provided the Commission with the confidential materials for its review, and has included redacted copies of these attachments in the filing.

Thank you for your attention to this filing. If you have any questions, please do not hesitate to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

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

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

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2012
Docket No. 4346

NATIONAL GRID'S REQUEST FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

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

I. BACKGROUND

On September 4, 2012, National Grid filed with the Commission its Annual Gas Cost Recovery filing in this docket. This filing included information relative to the Company's summary of estimated gas costs for 2012-2013 (Attachment EDA-1) and the Distrigas contract (Attachment EDA-2) and relative to forecasted basis numbers (Attachments EDA-2 and EDA-4) for which National Grid is requesting confidential treatment.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §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.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

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

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

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

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

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

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under that balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

II. BASIS FOR CONFIDENTIALITY

The Company has redacted estimated gas costs for 2012-2013 that appear in Attachment EDA-1 as well as forecasts of basis numbers that appear in Attachment EDA-2 and Attachment EDA-4. The Company seeks protective treatment for pricing information under its contract with Distrigas and for its basis number information, which provides price forecasts at specific points where gas is purchased. This basis information is assembled by a third-party and purchased by the Company subject to contractual agreement to maintain it as proprietary and confidential information.

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to those previously identified portions of its GCR filing.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorney,

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Thomas R. Teehan, Esq. (RI Bar #4698)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7667

Dated: September 4, 2012

DIRECT TESTIMONY

OF

ELIZABETH D. ARANGIO

September 4, 2012

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. WHAT IS YOUR POSITION WITH NATIONAL GRID?

A. I am the Director of Gas Supply Planning with responsibility for the resource portfolio of the New England local gas distribution companies ("LDC's") that operate as Boston Gas Company ("Boston Gas"), Colonial Gas Company ("Colonial") and The Narragansett Electric Company ("Narragansett") each d/b/a National Grid. In addition to the New England portfolios, I am also responsible for gas supply planning for the resource portfolios of The Brooklyn Union Gas Company, KeySpan Gas East Corporation and Niagara Mohawk Power Company, all in New York. For purposes of this testimony, references to "National Grid" or 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 Business Administration. In 1995, I graduated from Bentley College with a Master of Business

Administration. From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services, with responsibility for managing all activities associated with the Customer-Choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services with responsibility for the administration of the Company's 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 New York and Long Island resource portfolios. Following the acquisition of KeySpan Corporation by National Grid, plc, I was named to my current position with the added responsibility for the National Grid gas resource portfolios in upstate New York and in Rhode Island.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

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

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have recently testified before the Rhode Island Public Utility Commission in support of National Grid's Annual Gas Cost Recovery ("GCR") (Docket No. 4283), the Natural Gas Portfolio Management Plan ("NGPMP") (Docket No. 4038) and the Long Range Gas Supply plan. In the past, I have testified numerous times before the Massachusetts Department of Public Utilities, and the New Hampshire Public Utilities Commission. In addition I have also presented information to the State of New York Department of Public Service.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides support for the estimated gas costs, assignments of pipeline capacity to marketers and other issues relating to the Company's proposed Gas Cost Recovery ("GCR") factors.

Q. ARE YOU SPONSORING ATTACHMENTS TO YOUR TESTIMONY?

A. Yes. I am sponsoring the following attachments:

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

II. PROJECTED GAS COSTS

Q. WHAT COMMODITY PRICES WERE USED TO DEVELOP THE PROPOSED GCR FACTORS?

A. In terms of commodity prices, the proposed GCR factors are based on the following: (1) the NYMEX strip as of the close of trading on August 1, 2012 and (2) the difference between the futures contract purchases under the Gas Procurement Incentive Plan ("GPIP") as of July 31, 2012 and the August 1, 2012 NYMEX strip. The GCR factors also reflect storage and inventory costs as of July 31, 2012, as well as the projected cost of purchasing gas ratably through the remainder of the injection season, as provided for in the NGPMP. Attachment EDA-1 provides a summary of gas costs by major cost categories. Attachment EDA-2 shows the details of the calculations including the cost detail by supply source and the cost impact of financial hedges.

Q. OVERALL WHAT ARE THE NYMEX PRICES FOR GAS SUPPLIES PROJECTED TO BE PURCHASED IN THE GCR YEAR AND HOW DO THEY COMPARE TO LAST YEAR'S PRICES?

A. Attachment EDA-3 is a graph that compares NYMEX pricing from August 1, 2011 utilized in the Company's filing last year to NYMEX pricing from August 1, 2012 used in this instant filing.

Q. PLEASE DESCRIBE HOW GAS COSTS ARE CALCULATED.

A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT model to perform a dispatch optimization of the entire Rhode Island portfolio of gas supply, pipeline transportation, underground storage and peaking supplies. The model uses commodity price, pipeline contract and storage information to determine the dispatch of supplies to minimize the cost of supply over the year. The pricing of various pipeline services is based directly on the pipeline tariffs and the prices in effect as of August 1, 2012. For Company 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 five components: (1) Supply Fixed Costs; (2) Supply Variable Costs; (3) Storage Fixed Costs; (4) Storage Variable Product Costs; and (5) Storage Variable Non-Product Costs.[1] Each is described below.

1. The Supply Fixed Cost component includes pipeline demand charges.

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[1] The modification of the rate design from five components to two components is address in the testimony of Ms. Leary.

2. The Supply Variable Cost component includes; (1) commodity costs of all firm gas supplies and (2) variable costs to transport these gas supplies to the Company's distribution system. The volumes included in this component reflect the sum of purchases made under the GPIP. The projections of gas costs are based on the August 1, 2012 NYMEX strip adjusted for the basis differentials between the point of purchase and Henry Hub

3. The Storage Fixed Cost component includes; (1) pipeline underground and LNG storage demand charges and (2) pipeline demand charges for contracts associated with the transportation of storage gas to the Company's distribution system.

4. The Storage Product Cost component includes; (1) the commodity cost of the underground-storage gas supplies priced at the weighted-average cost of gas in storage ("WACOG"); (2) storage injection costs; and (3) the cost of LNG supplies which also includes the commodity cost of the gas, trucking costs and any demand charge component converted to a per-unit charge.

5. The Storage Variable Non-Product Cost component includes all variable costs related to the withdrawal and delivery of storage gas to the Company's Distribution System.

A summary of gas costs included in the GCR and disaggregated into these cost components by month for the period November 2012 through October 2013 is shown on Attachment EDA-1.

Q. PLEASE DESCRIBE ATTACHMENT EDA-2, PAGES 1 THROUGH 17.

A. Attachment EDA-2 shows the supporting detail for gas costs included in the filing for the period November 2012 through October 2013. The first two pages show the optimized, forecasted sendout by supply source under normal weather from the SENDOUT model and the detailed makeup of supply by pipeline source, storage contract and peaking facility. The next section, pages 3 through 6, shows the calculation of the per unit delivered cost for each pipeline path based on the August 1st NYMEX strip, including both pipeline variable charges and pipeline fuel losses. Pages 7 through 9 show the calculation of the delivered cost for each path (the price times the quantity). Pages 10 through 14 show the detailed calculation of total fixed costs.

The cost details for gas injected into and withdrawn from underground storage are shown on pages 15 and 16 while the total costs for LNG are shown on page 17. As the Company has yet to contract for LNG supplies for the upcoming 2012/13 year, pricing included in this filing reflects contractual terms from the Company’s contracts with Distrigas during the 2011/12 year. Charges for the Distrigas contracts have been redacted in the public version of the filing in order to comply with confidentiality terms.

Q. HOW DO YOU CALCULATE THE DELIVERED COST FOR A PARTICULAR GAS SUPPLY?

A. On Attachment EDA-2, page 3, the second supply source shown is gas purchased on Tennessee Pipeline in Zone 0, located in South Texas. The calculation for November begins with the $3.297 NYMEX price which is then adjusted for basis by, in this case, subtracting $0.080. This reflects the forward basis strip for gas supply in South Texas delivered into Tennessee Pipeline. Next the price is adjusted to reflect the fuel retention percentage of the pipeline, 4.00%, to bring the price to $3.351. That adjustment is made by dividing the price by one minus the loss factor, .9600, effectively adjusting the commodity price to incorporate the fact that only 96.00% of the supply delivered to the pipeline in South Texas will be delivered to Rhode Island. The pipeline usage fee of 31.42 cents is then added to reflect the cost of transportation on the pipeline, resulting in a delivered cost of $3.6652 per Dth.

III. MARKETER CAPACITY ASSIGNMENT

Q. WHAT TRANSPORTATION PATHS WILL BE AVAILABLE FOR ASSIGNMENT TO MARKETERS?

A. Attachment EDA-4, page 1 shows the paths and corresponding quantities available for assignment to marketers. In total, the Company has made available **32,758** Dth per day of capacity on six different pipeline paths. The volume allocated to the marketers remains the same as provided in the 2011/12 GCR filing.

Q. PLEASE EXPLAIN THE SURCHARGE/CREDIT CALCULATION FOR EACH ASSIGNED PIPELINE PATH?

A. The first step in calculating the adjustment charge for each path starts with calculating the system-average cost. The derivation of the weighted-average pipeline path cost of $0.8601 per Dth is shown at Attachment EDA-4, Page 10. This cost is equal to the sum of the 100% load factor fixed-cost unit value, the system-average unit variable cost and two (2) years of marketer reconciliation represented as a 100% load factor per unit cost. The 100% load factor fixed-cost unit value is $0.5591 per Dth. The system-average pipeline unit variable cost is $0.2693 per Dth. The sum of these components results in a weighted average pipeline cost of $0.8284 per Dth.

Q. HOW ARE THE DELIVERED COSTS FOR EACH PATH RELEASED TO MARKETERS DEVELOPED IN EDA-4?

A. The calculations for the delivered cost for each path are similar to those described for the system average. For illustration, the calculation for the first path (Tennessee Zone 1, shown on Attachment EDA-4, page 6) is comprised of a single contract originating in Zone 1 and terminating in Zone 6. Total fixed costs of $2,570,951 and total variable costs of $14,012,484 are shown near the bottom, right of page 6 of EDA-4. Commodity gas costs of $12,607,260 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 $0.7414 per Dth at 100% load factor plus the non-gas variable unit cost of $0.4053 per Dth, or $1.1467 per Dth. The unit cost of $1.1467 per Dth represents the direct costs incurred by the marketer, which are paid directly to the pipeline by the marketer. Since this cost is $0.2866 per Dth greater than the system-average, marketers electing this path would be credited $0.2866 per Dth per day on their monthly invoice from the Company. A summary of the individual path costs and associated credits or surcharges, for which approval is sought, is shown on Page 1 of EDA-4.

Q. HAS THE COMPANY COMPLIED WITH ITEM NO. 6 FROM THE DIVISION OF PUBLIC UTILITIES AND CARRIERS SETTLEMENT AGREEMENT IN DOCKET 4283?

A. Yes. The Commission ordered the Company to file a Long-Term Gas Supply Planning Study. On March 8, 2012 the Company submitted a Long-Range Resource and Requirements Plan (“Supply Plan”), for the forecast period November 1, 2011 through October 31, 2016.

The filing addresses issues raised by the Rhode Island Division of Public Utilities and Carriers ("Division") regarding the Company's 2011/12 GCR Filing, filed in Docket No. 4283. In addition, this filing provides a review of the LNG System Pressure study that the Company agreed to perform as a result of Docket 4199. The study was performed to ensure that calculation is appropriate, or whether changes are necessary to the system pressure calculation. The Company continues to hold discussions with the Division with regards to the system pressure calculation.

IV. GAS SUPPLY PORTFOLIO

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPANY'S INTERSTATE PIPELINE CAPACITY?

A. Yes. The Company's latest capacity change occurred November 1, 2011 with the conversion of the Company's TransCanada long-haul capacity being replaced with Union Gas Limited ("Union") and TransCanada Pipelines Limited ("TransCanada") short-haul pipeline capacity. By converting the long-haul capacity to short-haul capacity, the Company saves its customers approximately $500,000 a year in pipeline demand charges.

The Company has a total firm capacity entitlement of 1,025 MMBtus/day on the Union Gas pipeline system. The capacity path originates at Dawn, Ontario Canada and delivers into TransCanada at Parkway. In addition, the Company will have firm capacity entitlements of 1,012 MMBtus/day on the TransCanada pipeline system. The capacity path originates at the interconnection with Union Gas at Parkway and delivers into Iroquois Gas Transmission ("Iroquois") at Waddington, New York. This supply is delivered to the Company's distribution system on Company's existing transportation contracts on the Iroquois and Tennessee Gas Pipeline ("Tennessee").

Q. HOW DID THE COMPANY SUPPLY THE DAWN CAPACITY FOR THE 2011/12 YEAR?

A. Leading up to the conversion of the Company's TransCanada Gas Pipeline ("TCPL") long-haul to short-haul capacity, the Company issued a request for Proposal ("RFP") on September 23, 2011 for an Asset Management and Gas Supply Agreement ("AMA") effective November 1, 2011 for a term of one year. With the utilization of the SENDOUT® Model, the appropriate resource mix was determined to establish volume requirements for the term of the agreement. Subject to satisfying the gas supply requirements associated with the AMA, the seller has the right to utilize and optimize the transportation agreement for its own account. In exchange for such right, the seller pays the Company an optimization fee.

BG Energy Merchants, LLC ("BG") was awarded the bid to manage the assets and provide the Company with deliveries at the Canadian-US border at Waddington, New York. The Company then transported these volumes on Iroquois and Tennessee to the Company's citygates. This AMA provided the opportunity to extract value from temporarily-unused assets, subject to market conditions.

Q. WHAT ARE THE COMPANY'S PLANS TO SUPPLY THE DAWN CAPACITY FOR 2012/13 YEAR?

A. The Company issued an RFP on July 16, 2012 for an Asset Management and Gas Supply Agreement ("AMA"), similar to the RFP issued last year, to be effective November 1, 2012 for a term of one year. The RFP requested a maximum daily quantity ("MDQ") of 1,025 MMBtu/day of baseload for the months of November 2012 through March 2013.

Shell Energy North America U.S. ("Shell") was awarded the bid to manage the assets and provide the Company with deliveries at the Canadian-US border at Waddington, New York. The Company will then transport these volumes on Iroquois and Tennessee to the Company's citygates.

Q. WHAT ARE THE COMPANY'S PLANS TO SUPPLY THE EAST-TO-WEST PROJECT FOR 2012/13 YEAR?

A. The Company issued an RFP on July 9, 2012 for an Asset Management and Gas Supply Agreement ("AMA"), similar to the RFP issued last year, to be effective November 1, 2012 for a term of one year. Utilizing the SENDOUT® Model, the Company determined the appropriate resource mix and established the baseload and swing volume requirements by month.

The RFP requested a maximum daily quantity ("MDQ") of 10,000 MMBtu/day, the contractual volume under the Algonquin agreement, with both a baseload and swing component for the months of November 2012 through May 2012 and for the month of October 2012.

Please see Table 1 below for a description of the monthly baseload and swing quantities for the agreement.

TABLE 1

	Base-Load Supplies		**Daily Call**			**Supplemental Daily Call**		
Month	Maximum Daily Quantity	Maximum Monthly Quantity	Maximum Daily Quantity	Max. # of Days	Maximum Monthly Quantity	Maximum Daily Quantity	Max. # of Days	Maximum Monthly Quantity
Nov	0	0	10,000	20	200,000	10,000	10	100,000
Dec	3,000	93,000	7,000	12	84,000	7,000	19	133,000
Jan	3,000	93,000	7,000	14	98,000	7,000	17	119,000
Feb	3,000	84,000	7,000	14	98,000	7,000	14	98,000
Mar	0	0	10,000	20	200,000	10,000	11	110,000
Apr	0	0	10,000	20	200,000	0	0	0
May	0	0	3,000	13	39,000	0	0	0
Jun	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0
Oct	0	0	10,000	20	200,000	0	0	0

Subject to satisfying the gas supply requirements associated with the AMA, the Seller had the right to utilize and optimize the transportation agreement for its own account. In exchange for such right, the Seller paid the Company an optimization fee. EDF Trading North America, LLC (“EDF”) was awarded the bid to manage the assets and provide the asset management services for the 2012/13 season.

Q. ARE THERE ANY OTHER CONTRACT CHANGES AFFECTING THE SUPPLY PORTFOLIO AND GAS COSTS?

A. Yes. As it does each year, the Company will need to contract for LNG for the upcoming year. The Company contracted for a firm liquid supply contract which commenced on November 1, 2011 and expired on March 31, 2012 with Distrigas of Massachusetts LLC ("Distrigas"). The Company retained the right to purchase a quantity of LNG up to the MDQ of 3,000 MMBtu/day with a total quantity during the term of up to 125,000 MMBtus. The contract was structured to allow the Company to back fill its LNG facilities in the event of design weather during the Peak Season. Additionally, the Company also has an agreement with Distrigas for off-peak liquid refill. The Company has the right to purchase a quantity of LNG up to the MDQ of 4,000 MMBtu/day with a total quantity during the term of up to 552,000 MMBtu. The Company is in discussions with Distrigas for the 2012/13 peak season with similar requirements.

Finally, as it has in previous years, the Company will contract for a dedicated trucking arrangement in order to guarantee the availability of both trailers and drivers to truck the LNG from the Distrigas terminal to the Company's facilities during the peak season. The Company plans to issue an RFP for these services.

Q. ARE THERE ANY GAS RESOURCE PORTFOLIO RECOMMENDATIONS?

A. Yes. The Company is responsible for planning its gas supply portfolio in order to serve customer requirements for all firm customers, both sales and transportation, with the exception of those customers who are grandfathered and not required to take mandatory assignment of capacity. Thus, the Company must plan for firm sales customers, FT-1 and FT-2 transportation customers.

Under the Company's Customer Choice Program, marketers are required to accept mandatory capacity assignment on behalf of customers. FT-1 customers are assigned an allocation of their peak day usage of pipeline assets only, whereas FT-2 customers are assigned an allocation of their peak day usage, including pipeline, storage and peaking assets.

In the Company's Gas Cost Recovery ("GCR") filing each year, the Company attempts to account for customer choice migration by subtracting the load associated with FT-1 and FT-2 customers, while also reflecting the capacity that has been released to marketers as of a certain point in time. By eliminating the load and capacity, the GCR rates are then calculated for remaining sales customers only. While this process has worked successfully in the past, as more customers migrate to transportation, it has become apparent that the process needs to be modernized in order to make certain the appropriate level of assets are contracted for and that the cost of the resources are recovered by the appropriate customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

National Grid
Rhode Island - Gas

Attachment EDA-1
Redacted
Docket No. 4346
September 4, 2012

SUMMARY OF ESTIMATED GAS COSTS FOR 2012-2013 GCR Estimate

08/01/2012 NYMEX

Variable Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	GCR TOTAL
Total Pipeline Supply Costs	$10,611,606	$16,957,885	$17,853,651	$15,285,243	$15,867,984	$9,175,517	$5,352,229	$3,210,580	$2,799,528	$2,756,658	$2,810,260	$5,035,992	$107,717,133
Total Storage Product Costs	$0	$1,611,095	$6,922,920	$5,134,424	$245,598	$0	$0	$0	$0	$0	$0	$112,685	$14,026,722
Total Storage Delivery Costs	$0	$34,268	$174,468	$136,135	$5,721	$0	$0	$0	$0	$0	$0	$4,682	$355,274
Total LNG Costs	$105,291	$510,215	$350,598	$201,062	$109,212	$105,291	$109,212	$108,710	$115,127	$115,127	$110,994	$115,499	$2,056,336
Total All Variable Gas Costs	$10,716,897	$19,113,463	$25,301,637	$20,756,863	$16,228,514	$9,280,808	$5,461,441	$3,319,290	$2,914,655	$2,871,784	$2,921,254	$5,268,858	$124,155,464
Fixed Costs													
TOTAL PIPELINE DEMANDS	$2,939,236	$2,939,879	$2,938,539	$2,936,610	$2,938,539	$2,937,896	$2,938,539	$2,937,896	$2,938,539	$2,938,539	$2,937,896	$2,938,539	$35,260,650
TOTAL STORAGE FACILITIES	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$402,997	$4,835,962
TOTAL STORAGE DELIVERY	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$424,228	$5,090,738
TOTAL SUPPLIER DEMANDS	[redacted]												
Total All Fixed Costs	$3,885,211	$3,885,854	$3,884,514	$3,882,585	$3,884,514	$3,890,504	$3,891,147	$3,890,504	$3,891,147	$3,891,147	$3,890,504	$3,891,147	$46,658,779
Capacity Release Credits	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$551,270	$6,615,235
NGPMP Credit	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$383,333	$4,600,000
Net Fixed Costs	$2,950,608	$2,951,251	$2,949,911	$2,947,982	$2,949,911	$2,955,901	$2,956,544	$2,955,901	$2,956,544	$2,956,544	$2,955,901	$2,956,544	$35,443,545
Total All Gas Costs	$13,667,505	$22,064,714	$28,251,548	$23,704,846	$19,178,426	$12,236,710	$8,417,985	$6,275,191	$5,871,199	$5,828,328	$5,877,155	$8,225,402	$159,599,009

REDACTED VERSION

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV 2012	DEC 2012	JAN 2013	FEB 2013	MAR 2013	APR 2013	MAY 2013	JUN 2013	JUL 2013	AUG 2013	SEP 2013	OCT 2013	Total/Average
Forecast Demand													
RI Sales GCR	2,223,400	3,797,000	4,509,900	3,856,200	3,413,900	2,117,600	1,259,500	749,200	610,400	608,200	661,700	1,269,600	25,076,600
Total Demand	2,223,400	3,797,000	4,509,900	3,856,200	3,413,900	2,117,600	1,259,500	749,200	610,400	608,200	661,700	1,269,600	25,076,600
Storage Injections													
TENN 501	0	0	0	0	0	118,800	122,700	118,800	0	0	0	0	360,300
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	0	0	0	0	21,000	21,700	0	0	0	0	0	42,700
GSS 300171	0	0	0	0	0	15,800	16,200	15,700	16,200	16,200	15,700	16,200	112,000
GSSTE 600045	0	0	0	0	0	187,800	194,000	42,800	0	0	0	0	424,600
TETCO 400515	0	0	0	0	0	8,700	9,000	8,700	2,000	0	0	0	28,400
TETCO 400221	0	0	0	0	0	181,800	187,800	181,800	42,600	0	0	0	594,000
TETCO 400185	0	0	0	0	0	8,000	5,000	0	0	0	0	0	13,000
GSS 300169	0	0	0	0	0	29,200	29,100	28,100	17,500	0	0	0	103,900
COL FSS 9630	0	0	0	0	0	30,600	40,800	0	21,600	23,200	26,500	0	142,700
TENN 62918	0	0	0	0	0	41,200	42,600	41,200	0	0	0	0	125,000
Total Underground Storage	0	0	0	0	0	642,900	668,900	437,100	99,900	39,400	42,200	16,200	1,946,600
LNG PROV	0	0	0	0	0	0	107,100	120,400	0	0	35,800	12,100	275,400
LNG VALLEY	0	0	0	0	0	0	19,900	5,000	0	0	9,400	3,200	37,500
LNG EXETER	0	0	0	0	0	0	28,200	4,500	0	0	12,400	4,200	49,300
Total LNG Injection	0	0	0	0	0	0	155,200	129,900	0	0	57,600	19,500	362,200
Total Injections	0	0	0	0	0	642,900	824,100	567,000	99,900	39,400	99,800	35,700	2,308,800

Delivered Firm Sales Supply

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENN CONX	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	4,234,000
TENN ZONE 0	56,252	183,396	162,135	180,085	122,567	107,993	60,699	39,341	0	0	0	0	912,470
TENN ZONE 1	117,048	381,604	337,365	374,715	255,033	224,707	126,301	81,859	0	0	0	0	1,898,630
TENN NIAGARA	0	3,200	0	0	0	32,000	0	0	0	0	0	0	35,200
TENN DRACUT	0	35,000	0	0	0	0	19,200	0	0	0	0	0	54,200
COL MAUMEE	762,400	1,173,100	1,172,900	1,059,400	1,172,900	774,600	82,400	102,800	1,700	0	0	41,900	6,344,100
COL BROADRUN	291,400	300,900	300,800	271,700	300,800	291,600	301,400	291,400	251,300	252,500	291,600	301,100	3,446,500
TRANSCO Z2	3,915	4,013	4,013	3,621	0	0	0	0	0	0	0	0	15,562
TRANSCO Z3	85	87	87	79	0	0	0	0	0	0	0	0	338
TETCO ELA	0	230,267	326,736	260,657	0	164,378	168,230	105,658	29,856	6,177	5,986	6,177	1,304,123
TETCO ETX	0	68,982	97,881	78,086	0	49,243	50,397	31,652	8,944	1,850	1,793	1,850	390,681
TETCO STX	0	102,816	145,890	116,385	0	73,396	75,116	47,177	13,331	2,758	2,673	2,758	582,300
TETCO WLA	0	158,251	224,549	179,136	0	112,969	115,615	72,613	20,518	4,245	4,114	4,245	896,256
TETCO to B&W - SCT	0	25,604	36,331	28,983	0	18,278	18,706	11,748	3,320	687	666	687	145,010
TETCO - NF - TRANSCO	0	11,283	16,011	12,773	0	8,055	8,243	5,177	1,463	303	293	303	63,904
TETCO - DTI - TETCO	0	6,697	9,502	7,581	0	4,781	4,893	3,073	868	180	174	180	37,928
M3 DELIVERED	595,600	304,600	203,700	125,100	1,119,700	531,500	518,400	27,000	0	0	29,800	518,400	3,973,800
HUBLINE	0	109,000	92,100	83,100	0	0	0	0	0	0	0	0	284,200
COL EAGLE	0	0	0	0	0	0	0	0	0	0	0	0	0
COL DOWNINGTOWN	0	0	0	0	0	0	0	0	0	0	0	0	0
ANE II - DAWN-TENN	30,000	31,000	31,000	28,000	31,000	0	0	0	0	0	0	0	151,000
DISTRIGAS NSB Winter	0	0	0	0	0	0	0	0	0	0	0	0	0
DISTRIGAS NSB Summer	0	0	0	0	0	0	155,000	129,900	0	0	57,700	19,400	362,000
NEWPORT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0
SPOT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

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Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
Non LNG Liquid take	2,204,700	3,489,400	3,520,600	3,134,200	3,361,600	2,741,500	1,909,200	1,167,500	690,900	628,300	685,100	1,237,200	24,770,200
LNG Liquid take	0	0	0	0	0	0	155,000	129,900	0	0	57,700	19,400	362,000
Total take	2,204,700	3,489,400	3,520,600	3,134,200	3,361,600	2,741,500	2,064,200	1,297,400	690,900	628,300	742,800	1,256,600	25,132,200
Storage Withdrawals													
TENN 501	0	44,700	174,900	117,700	7,500	0	0	0	0	0	0	11,200	356,000
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	14,000	20,600	0	0	0	0	0	0	0	0	7,600	42,200
GSS 300171	0	0	68,300	41,100	0	0	0	0	0	0	0	0	109,400
GSSTE 600045	0	99,600	166,400	147,800	0	0	0	0	0	0	0	0	413,800
TETCO 400515	0	0	13,400	13,400	0	0	0	0	0	0	0	0	26,800
TETCO 400221	0	0	284,300	284,300	0	0	0	0	0	0	0	0	568,600
TETCO 400185	0	0	12,400	0	0	0	0	0	0	0	0	0	12,400
GSS 300169	0	0	53,500	46,300	0	0	0	0	0	0	0	0	99,800
COL FSS 9630	0	38,800	39,100	35,300	25,400	0	0	0	0	0	0	0	138,600
TENN 62918	0	19,200	93,900	0	0	0	0	0	0	0	0	10,400	123,500
LNG PROV	11,700	83,700	55,100	29,300	12,100	11,700	12,100	11,700	12,100	12,100	11,700	12,100	275,400
LNG VALLEY	3,100	3,200	3,200	2,800	3,200	3,100	3,200	3,100	3,200	3,200	3,100	3,100	37,500
LNG EXETER	4,000	4,200	4,300	3,800	4,200	4,000	4,200	4,000	4,200	4,200	4,000	4,200	49,300
Total Withdrawal Delivered	18,800	307,400	989,400	721,800	52,400	18,800	19,500	18,800	19,500	19,500	18,800	48,600	2,253,300
Total Storage withdrawal	0	216,300	926,800	685,900	32,900	0	0	0	0	0	0	29,200	1,891,100
Total Peaking withdrawal	18,800	91,100	62,600	35,900	19,500	18,800	19,500	18,800	19,500	19,500	18,800	19,400	362,200
Total Supply	**2,223,500**	**3,796,800**	**4,510,000**	**3,856,000**	**3,414,000**	**2,760,300**	**1,928,700**	**1,186,300**	**710,400**	**647,800**	**703,900**	**1,285,800**	**27,023,500**
Storage withdrawals at Storage Facilty													
TENN 501	0	45,300	177,000	119,100	7,600	0	0	0	0	0	0	11,300	360,300
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	14,200	20,800	0	0	0	0	0	0	0	0	7,700	42,700
GSS 300171	0	0	69,900	42,100	0	0	0	0	0	0	0	0	112,000
GSSTE 600045	0	102,200	170,700	151,700	0	0	0	0	0	0	0	0	424,600
TETCO 400515	0	0	14,200	14,200	0	0	0	0	0	0	0	0	28,400
TETCO 400221	0	0	297,000	297,000	0	0	0	0	0	0	0	0	594,000
TETCO 400185	0	0	13,000	0	0	0	0	0	0	0	0	0	13,000
GSS 300169	0	0	55,700	48,200	0	0	0	0	0	0	0	0	103,900
COL FSS 9630	0	40,000	40,100	36,400	26,200	0	0	0	0	0	0	0	142,700
TENN 62918	0	19,500	95,000	0	0	0	0	0	0	0	0	10,500	125,000
	0	221,200	953,400	708,700	33,800	0	0	0	0	0	0	29,500	1,946,600

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Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
08/01/2012 NYMEX	**$3.297**	**$3.540**	**$3.653**	**$3.664**	**$3.637**	**$3.607**	**$3.629**	**$3.665**	**$3.708**	**$3.729**	**$3.734**	**$3.762**	
TENNESSEE CONNEXION													
Basis	[redacted]												
usage to Zn 6	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
fuel to Zn 6	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	
Total Delivered	[redacted]												
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	
fuel	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	
Total Delivered	[redacted]												
TENNESSEE ZN 1													
Basis	[redacted]												
usage to Zn 6	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	
fuel to Zn 6	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	
Total Delivered	[redacted]												
TENNESSEE DRACUT													
Basis $0.800	[redacted]												
usage	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	
fuel	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	
Total Delivered	[redacted]												
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	6.95%	8.21%	8.21%	8.21%	8.21%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO ETX													
Basis	[redacted]												
Usage to M3	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	6.95%	8.21%	8.21%	8.21%	8.21%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

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	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO STX													
Basis	[redacted]												
Usage to M3	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	7.95%	9.59%	9.59%	9.59%	9.59%	7.95%	7.95%	7.95%	7.95%	7.95%	7.95%	7.95%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	7.25%	8.64%	8.64%	8.64%	8.64%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO -> NF -> TRANSCO													
Basis	[redacted]												
Usage to M2	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	
Usage on NF	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	
Usage on Transco	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	
Usage on AGT	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	
Fuel to M2	6.19%	7.19%	7.19%	7.19%	7.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	
Fuel on NF	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	
Fuel on Transco	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Delivered to NF	[redacted]												
Delivered to Transco													
Delivered to Algonquin													
Total Delivered													
M3 DELIVERED													
Basis	[redacted]												
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
COLUMBIA MAUMEE													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

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	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
COLUMBIA BROADRUN													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
COLUMBIA EAGLE													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
COLUMBIA DOWNINGTOWN													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO -> DTI -> TETCO													
Basis	[redacted]												
Usage to M2	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	
Usage on Dominion	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	
Usage on Tetco	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
Usage on AGT	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	
Fuel to M2	6.19%	7.19%	7.19%	7.19%	7.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	
Fuel on Dominion	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Delivered to Dominion	[redacted]												
Delivered to Tetco													
Delivered to Algonquin													
Total Delivered													
TRANSCO ZONE 2													
Basis	[redacted]												
Usage on Transco	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	
Usage on Tetco	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Transco	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
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Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TRANSCO ZONE 3													
Basis	[redacted]												
Usage on Transco	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	
Usage on Tetco	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Transco	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
DAWN TO TENNESSEE - ANE II													
Basis	[redacted]												
Transcanada usage	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
Transcanada pressure chg	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	
Iroquois usage	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	
Tenn usage	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	
Fuel on Union	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	
Fuel on TCPL	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	
Fuel on Iroquois	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
Fuel on Tenn	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	[redacted]												
NIAGARA TO TENNESSEE													
Basis	[redacted]												
Tenn usage	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	
Tenn Fuel	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	[redacted]												
Tetco to B&W - SCT													
Basis	[redacted]												
usage on Tetco	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	
usage on AGT	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	
fuel to ZN 3	7.20%	8.56%	8.56%	8.56%	8.56%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
Hubline													
Basis $0.8680	[redacted]												
usage	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
fuel	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

REDACTED VERSION

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
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Natural Gas Supply VS. Requirements Units: DTH

Total Delivered to the City Gate Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TENN CONNEXION													
Delivered Mmbtu	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	
NYMEX $/Mmbtu Del	$3.353	$3.606	$3.739	$3.730	$3.712	$3.671	$3.699	$3.741	$3.791	$3.813	$3.813	$3.832	
Total Delivered Cost	$1,166,789	$1,296,706	$1,344,652	$1,211,480	$1,334,913	$1,277,351	$1,330,044	$1,302,001	$1,363,381	$1,371,248	$1,327,014	$1,377,990	
Tennessee Zn 0													
Delivered Mmbtu	56,252	183,396	162,135	180,085	122,567	107,993	60,699	39,341	0	0	0	0	
NYMEX $/Mmbtu Del	$3.665	$3.918	$4.052	$4.042	$4.025	$3.983	$4.011	$4.054	$4.104	$4.126	$4.126	$4.144	
Total Delivered Cost	$206,178	$718,614	$656,924	$727,964	$493,286	$430,130	$243,469	$159,480	$0	$0	$0	$0	
TENN ZONE 1													
Delivered Mmbtu	117,048	381,604	337,365	374,715	255,033	224,707	126,301	81,859	0	0	0	0	
$/Mmbtu Del	$3.749	$3.879	$4.016	$4.059	$4.060	$4.049	$4.043	$4.030	$4.088	$4.095	$4.211	$4.211	
Total Delivered Cost	$438,820	$1,480,095	$1,355,011	$1,520,947	$1,035,429	$909,746	$510,685	$329,886	$0	$0	$0	$0	
TENN DRACUT													
Delivered Mmbtu	0	35,000	0	0	0	0	19,200	0	0	0	0	0	
$/Mmbtu Del	$4.14	$5.80	$7.53	$6.64	$4.73	$4.04	$3.82	$3.88	$3.99	$4.03	$3.93	$4.06	
Total Delivered Cost	$0	$202,906	$0	$0	$0	$0	$73,308	$0	$0	$0	$0	$0	
TETCO ELA													
Delivered Mmbtu	0	230,267	326,736	260,657	0	164,378	168,230	105,658	29,856	6,177	5,986	6,177	
$/Mmbtu Del	$3.6343	$3.9527	$4.0815	$4.0892	$4.0595	$3.9598	$3.9836	$4.0401	$4.0693	$4.0965	$4.0976	$4.1279	
Total Delivered Cost	$0	$910,185	$1,333,569	$1,065,875	$0	$650,903	$670,168	$426,865	$121,494	$25,304	$24,530	$25,498	
TETCO ETX													
Delivered Mmbtu	0	68,982	97,881	78,086	0	49,243	50,397	31,652	8,944	1,850	1,793	1,850	
NYMEX $/Mmbtu Del	$3.5020	$3.8405	$3.9626	$3.9857	$3.9362	$3.8730	$3.8817	$3.9598	$4.0401	$4.0010	$4.0249	$4.0824	
Total Delivered Cost	$0	$264,924	$387,869	$311,230	$0	$190,720	$195,625	$125,337	$36,134	$7,404	$7,218	$7,554	
TETCO STX													
Delivered Mmbtu	0	102,816	145,890	116,385	0	73,396	75,116	47,177	13,331	2,758	2,673	2,758	
NYMEX $/Mmbtu Del	$3.622	$3.948	$4.069	$4.085	$4.057	$3.953	$3.980	$4.023	$4.083	$4.106	$4.106	$4.132	
Total Delivered Cost	$0	$405,946	$593,618	$475,384	$0	$290,130	$298,987	$189,799	$54,435	$11,326	$10,976	$11,396	
TETCO WLA													
Delivered Mmbtu	0	158,251	224,549	179,136	0	112,969	115,615	72,613	20,518	4,245	4,114	4,245	
$/Mmbtu Del	$3.6760	$4.0015	$4.0866	$4.0988	$4.0689	$3.9774	$4.0014	$4.0242	$4.0906	$4.1145	$4.1156	$4.1461	
Total Delivered Cost	$0	$633,238	$917,645	$734,239	$0	$449,324	$462,619	$292,212	$83,932	$17,467	$16,932	$17,601	

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO -> NF -> TRANSCO													
Delivered Mmbtu	0	11,283	16,011	12,773	0	8,055	8,243	5,177	1,463	303	293	303	
Delivered $/Mmbtu	$4.2501	$4.5594	$4.6885	$4.6963	$4.6665	$4.5775	$4.6015	$4.6582	$4.6877	$4.7150	$4.7161	$4.7466	
Delivered Cost	$0	$51,446	$75,066	$59,983	$0	$36,871	$37,932	$24,118	$6,858	$1,427	$1,383	$1,437	
M3 DELIVERED													
Delivered Mmbtu	595,600	304,600	203,700	125,100	1,119,700	531,500	518,400	27,000	0	0	29,800	518,400	
Delivered $/Mmbtu	$3.5509	$4.2473	$4.8090	$4.4968	$3.8908	$3.7901	$3.7952	$3.8315	$3.9052	$3.9264	$3.8406	$3.8759	
Delivered Cost	$2,114,918	$1,293,741	$979,585	$562,554	$4,356,504	$2,014,453	$1,967,418	$103,451	$0	$0	$114,450	$2,009,280	
COLUMBIA MAUMEE													
Delivered Mmbtu	762,400	1,173,100	1,172,900	1,059,400	1,172,900	774,600	82,400	102,800	1,700	0	0	41,900	
Delivered $/Mmbtu	$3.4415	$3.6912	$3.8076	$3.8158	$3.7777	$3.7853	$3.7977	$3.8245	$3.8584	$3.8698	$3.8646	$3.8832	
Total Delivered Cost	$2,623,770	$4,330,104	$4,465,923	$4,042,493	$4,430,877	$2,932,130	$312,931	$393,156	$6,559	$0	$0	$162,704	
COLUMBIA BROADRUN													
Delivered Mmbtu	291,400	300,900	300,800	271,700	300,800	291,600	301,400	291,400	251,300	252,500	291,600	301,100	
Delivered $/Mmbtu	$3.3972	$3.6675	$3.7921	$3.7777	$3.7190	$3.7153	$3.7668	$3.7833	$3.8131	$3.8183	$3.7926	$3.7884	
Total Delivered Cost	$989,941	$1,103,540	$1,140,674	$1,026,404	$1,118,670	$1,083,391	$1,135,318	$1,102,450	$958,244	$964,119	$1,105,909	$1,140,698	
COLUMBIA EAGLE													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.6474	$4.3578	$4.9306	$4.6123	$3.9941	$3.8914	$3.8965	$3.9336	$4.0088	$4.0304	$3.9429	$3.9789	
Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
COLUMBIA DOWNINGTOWN													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.6711	$4.4165	$5.1676	$4.8008	$4.0250	$3.8986	$3.8924	$3.9295	$4.0222	$4.0407	$3.9429	$3.9758	
Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO -> DTI -> TETCO													
Delivered Mmbtu	0	6,697	9,502	7,581	0	4,781	4,893	3,073	868	180	174	180	
Delivered $/Mmbtu	$4.3630	$4.6810	$4.8138	$4.8217	$4.7911	$4.6996	$4.7243	$4.7826	$4.8129	$4.8410	$4.8421	$4.8735	
Delivered Cost	$0	$31,348	$45,743	$36,552	$0	$22,467	$23,114	$14,696	$4,179	$870	$843	$876	
TRANSCO ZONE 2													
Delivered Mmbtu	3,915	4,013	4,013	3,621	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.5477	$3.7953	$3.9370	$3.9168	$3.9306	$3.8842	$3.8906	$3.9577	$4.0109	$4.0163	$4.0269	$4.0567	
Delivered Cost	$13,889	$15,230	$15,798	$14,184	$0	$0	$0	$0	$0	$0	$0	$0	

REDACTED VERSION

National Grid
Rhode Island - Gas

Attachment EDA-2
Redacted
Docket No. 4346
September 4, 2012

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TRANSCO ZONE 3													
Delivered Mmbtu	85	87	87	79	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.5550	$3.8155	$3.9376	$3.9493	$3.9163	$3.8796	$3.9030	$3.9528	$3.9921	$4.0250	$4.0197	$4.0303	
Delivered Cost	$303	$333	$343	$311	$0	$0	$0	$0	$0	$0	$0	$0	
DAWN TO TENNESSEE - ANE II													
Delivered Mmbtu	30,000	31,000	31,000	28,000	31,000	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.9729	$4.2095	$4.2282	$4.2344	$4.2168	$4.0840	$4.1068	$4.1556	$4.1566	$4.1587	$4.2158	$4.2448	
Total Delivered Cost	$119,188	$130,495	$131,074	$118,564	$130,721	$0	$0	$0	$0	$0	$0	$0	
NIAGARA TO TENNESSEE													
Delivered Mmbtu	0	3,200	0	0	0	32,000	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.7755	$4.0894	$4.1075	$4.1136	$4.0964	$3.9168	$3.9390	$4.0036	$3.9925	$4.0086	$4.0450	$4.0732	
Total Delivered Cost	$0	$13,086	$0	$0	$0	$125,337	$0	$0	$0	$0	$0	$0	
Tetco to B&W - SCT													
Delivered Mmbtu	0	25,604	36,331	28,983	0	18,278	18,706	11,748	3,320	687	666	687	
Delivered $/Mmbtu	$4.3164	$4.6403	$4.7696	$4.7773	$4.7475	$4.6427	$4.6666	$4.7232	$4.7526	$4.7798	$4.7808	$4.8113	
Total Delivered Cost	$0	$118,811	$173,282	$138,462	$0	$84,858	$87,294	$55,490	$15,777	$3,283	$3,182	$3,305	
HUBLINE													
Total Delivered Vol	0	109,000	92,100	83,100	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.2171	$5.9524	$7.7635	$6.7494	$4.7675	$4.0980	$3.8699	$3.9728	$4.1212	$4.1424	$4.0294	$4.1515	
Total Delivered Cost	$0	$648,811	$715,019	$560,872	$0	$0	$0	$0	$0	$0	$0	$0	

	NOV 2012	**DEC** 2012	**JAN** 2013	**FEB** 2013	**MAR** 2013	**APR** 2013	**MAY** 2013	**JUN** 2013	**JUL** 2013	**AUG** 2013	**SEP** 2013	**OCT** 2013	
Financial Hedges as of 7/31/2012													
Quantity	2,270,000	2,940,000	3,080,000	2,600,000	2,460,000	1,408,642	766,518	575,561	590,230	478,018	591,194	582,274	**18,342,438**
Average Price	$4.591	$4.665	$4.796	$4.694	$4.843	$4.664	$4.790	$4.730	$4.761	$4.856	$4.381	$4.354	
08/01/2012 NYMEX	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
Impact of Financial Hedges	**$2,937,811**	**$3,308,328**	**$3,521,856**	**$2,677,745**	**$2,967,584**	**$1,488,598**	**$889,801**	**$612,975**	**$621,754**	**$538,642**	**$382,288**	**$344,471**	**$20,291,853.47**
Total Pipeline Costs (Incl Inj)	**$10,611,606**	**$16,957,885**	**$17,853,651**	**$15,285,243**	**$15,867,984**	**$11,986,410**	**$8,238,713**	**$5,131,917**	**$3,272,748**	**$2,941,090**	**$2,994,725**	**$5,102,809**	**$116,244,781**
Total Delivered Pipeline Vol	**2,204,700**	**3,489,400**	**3,520,600**	**3,134,200**	**3,361,600**	**2,741,500**	**1,909,200**	**1,167,500**	**690,900**	**628,300**	**685,100**	**1,237,200**	**24,770,200**
WACOG (Cost/Volume)	$4.813	$4.860	$5.071	$4.877	$4.720	$4.372	$4.315	$4.396	$4.737	$4.681	$4.371	$4.124	$4.693
Injections	0	0	0	0	0	642,900	668,900	437,100	99,900	39,400	42,200	16,200	
Cost of Injections	$0	$0	$0	$0	$0	$2,810,893	$2,886,484	$1,921,337	$473,220	$184,433	$184,466	$66,817	**$8,527,648**
Total GCR Cost Including Financial Hedges, Excluding Injections													
Total Pipeline Costs	**$10,611,606**	**$16,957,885**	**$17,853,651**	**$15,285,243**	**$15,867,984**	**$9,175,517**	**$5,352,229**	**$3,210,580**	**$2,799,528**	**$2,756,658**	**$2,810,260**	**$5,035,992**	**$107,717,133**
Total Pipeline Purchase Volumes	**2,204,700**	**3,489,400**	**3,520,600**	**3,134,200**	**3,361,600**	**2,098,600**	**1,240,300**	**730,400**	**591,000**	**588,900**	**642,900**	**1,221,000**	**22,823,600**

REDACTED VERSION

National Grid
Rhode Island - Gas

2012 GCR estimate
FIXED COST ESTIMATES
Nov 2012 - Oct 2013

2012-2013 Gas Supply Fixed Costs
UNIT PRICES

		NOV	DEC	JAN-13	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
PIPELINE FIXED COST UNIT PRICES $/Dth													
ALGONQUIN AFT-E/AFT-1 DEMAND	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909
ALGONQUIN HUBLINE DEMAND	$/Dth	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583
ALGONQUIN HUBLINE DEMAND	$/Dth	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958
ALGONQUIN HUBLINE DEMAND	$/Dth	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920
ALGONQUIN EAST TO WEST DEMAND	$/Dth	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341
COLUMBIA FTS DEMAND	$/Dth	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770
DOMINION FTNN DEMAND	$/Dth	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040
IROQUOIS DEMAND	$/Dth	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971
NATIONAL FUEL DEMAND	$/Dth	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$/Dth	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365
TENNESSEE FT-A DEMAND DRACUT	$/Dth	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396
TEXAS EASTERN CDS STX DEMAND M3	$/Dth	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050
TEXAS EASTERN CDS WLA DEMAND M3	$/Dth	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250
TEXAS EASTERN CDS ELA DEMAND M3	$/Dth	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750
TEXAS EASTERN CDS ETX DEMAND M3	$/Dth	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890
TEXAS EASTERN CDS 1-3 DEMAND M3	$/Dth	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240
TEXAS EASTERN FTS DEMAND	$/Dth	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510
TEXAS EASTERN SCT STX DEMAND M3	$/Dth	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220
TEXAS EASTERN SCT WLA DEMAND M3	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
TEXAS EASTERN SCT ELA DEMAND M3	$/Dth	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500
TEXAS EASTERN SCT ETX DEMAND M3	$/Dth	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760
TEXAS EASTERN SCT 1-3 DEMAND M3	$/Dth	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710
TEXAS EASTERN SCT STX DEMAND M2	$/Dth	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220
TEXAS EASTERN SCT WLA DEMAND M2	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
TEXAS EASTERN SCT ELA DEMAND M2	$/Dth	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500
TEXAS EASTERN SCT ETX DEMAND M2	$/Dth	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760
TEXAS EASTERN SCT 1-2 DEMAND M2	$/Dth	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290
TRANSCANADA DEMAND	$/Dth	$10.3350	$10.6795	$10.6795	$9.6460	$10.6795	$10.3350	$10.6795	$10.3350	$10.6795	$10.6795	$10.3350	$10.6795
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645
TRANSCO DEMAND ZONE 3 TO 6	$/Dth	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379
TRANSCO DEMAND ZONE 6	$/Dth	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194
UNION DEMAND	$/Dth	$2.3700	$2.4490	$2.4490	$2.2120	$2.4490	$2.3700	$2.4490	$2.3700	$2.4490	$2.4490	$2.3700	$2.4490
STORAGE FIXED COST UNIT PRICES													
COLUMBIA FSS DEMAND	$/Dth	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090	$1.5090
COLUMBIA FSS CAPACITY	$/Dth	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289	$0.0289
DOMINION GSS DEMAND	$/Dth	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788
DOMINION GSS CAPACITY	$/Dth	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145
DOMINION GSS-TE DEMAND	$/Dth	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788	$1.8788
DOMINION GSS-TE CAPACITY	$/Dth	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145
TENNESSEE FSMA DEMAND	$/Dth	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400	$1.5400
TENNESSEE FSMA CAPACITY	$/Dth	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211	$0.0211
TEXAS EASTERN SS-1 DEMAND	$/Dth	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070	$5.5070
TEXAS EASTERN SS-1 CAPACITY	$/Dth	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293
TEXAS EASTERN FSS-1 DEMAND	$/Dth	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950	$0.8950
TEXAS EASTERN FSS-1 CAPACITY	$/Dth	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293

National Grid
Rhode Island - Gas

STORAGE DELIVERY FIXED		NOV	DEC	JAN-13	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
UNIT RATES ($/Dth)													
PATH													
ALGONQUIN FOR TETCO SS-1	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN DELIVERY FOR FSS-1	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN SCT FOR SS-1	$/Dth	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN SCT DELIVERY FOR GSS-TE	$/Dth	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909
ALGONQUIN DELIVERY FOR GSS CONV.	$/Dth	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854
ALGONQUIN DELIVERY FOR FSS	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
COLUMBIA DELIVERY FOR FSS	$/Dth	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070	$5.9070
DOMINION DELIVERY FOR GSS	$/Dth	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040
DOMINION DELIVERY FOR GSS CONV.	$/Dth	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040
TENNESSEE DELIVERY FOR GSS	$/Dth	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896
TENNESSEE DELIVERY FOR FSMA	$/Dth	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896	$8.4896
TETCO DELIVERY FOR FSS-1	$/Dth	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580	$5.2580
TETCO DELIVERY FOR GSS/GSS-TE	$/Dth	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640
TETCO DELIVERY FOR GSS CONV.	$/Dth	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790
SUPPLIER FIXED COST UNIT PRICES													
DISTRIGAS NSB CALL PAYMENT Winter	$/Dth	[redacted]											
DISTRIGAS NSB CALL PAYMENT Summer	$/Dth												
								BILLING UNITS					
PIPELINE FIXED COST BILLING UNITS													
ALGONQUIN AFT-E/AFT-1 DEMAND	Dth	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285
ALGONQUIN AFT-3 DEMAND	Dth	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	Dth	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079
ALGONQUIN HUBLINE DEMAND	Dth	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
ALGONQUIN HUBLINE DEMAND	Dth	500	500	500	500	500	500	500	500	500	500	500	500
ALGONQUIN HUBLINE DEMAND	Dth	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
ALGONQUIN EAST TO WEST DEMAND	Dth	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
COLUMBIA FTS DEMAND	Dth	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
DOMINION FTNN DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
IROQUOIS DEMAND	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NATIONAL FUEL DEMAND	Dth	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	Dth	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
TENNESSEE FT-A DEMAND DRACUT	Dth	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TENNESSEE FT-A DEMAND ZONE 5 TO 6	Dth	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067
TEXAS EASTERN CDS STX DEMAND M3	Dth	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN CDS WLA DEMAND M3	Dth	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN CDS ELA DEMAND M3	Dth	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN CDS ETX DEMAND M3	Dth	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TEXAS EASTERN CDS 1-3 DEMAND M3	Dth	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TEXAS EASTERN FTS DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
TEXAS EASTERN SCT STX DEMAND M3	Dth	571	571	571	571	571	571	571	571	571	571	571	571
TEXAS EASTERN SCT WLA DEMAND M3	Dth	648	648	648	648	648	648	648	648	648	648	648	648
TEXAS EASTERN SCT ELA DEMAND M3	Dth	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TEXAS EASTERN SCT ETX DEMAND M3	Dth	329	329	329	329	329	329	329	329	329	329	329	329
TEXAS EASTERN SCT 1-3 DEMAND M3	Dth	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TEXAS EASTERN SCT STX DEMAND M2	Dth	401	401	401	401	401	401	401	401	401	401	401	401
TEXAS EASTERN SCT WLA DEMAND M2	Dth	455	455	455	455	455	455	455	455	455	455	455	455
TEXAS EASTERN SCT ELA DEMAND M2	Dth	831	831	831	831	831	831	831	831	831	831	831	831
TEXAS EASTERN SCT ETX DEMAND M2	Dth	231	231	231	231	231	231	231	231	231	231	231	231
TEXAS EASTERN SCT 1-2 DEMAND M2	Dth	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474
TRANSCANADA DEMAND	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
TRANSCO DEMAND ZONE 2 TO 6	Dth	4,140	4,278	4,278	3,864	4,278	4,140	4,278	4,140	4,278	4,278	4,140	4,278
TRANSCO DEMAND ZONE 3 TO 6.	Dth	90	93	93	84	93	90	93	90	93	93	90	93
TRANSCO DEMAND ZONE 6	Dth	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
UNION DEMAND	Dth	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025

REDACTED VERSION

National Grid
Rhode Island - Gas

Attachment EDA-2
Redacted
Docket No. 4346
September 4, 2012

		NOV	DEC	JAN-13	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
STORAGE FIXED COST BILLING UNITS													
COLUMBIA FSS DEMAND	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA FSS CAPACITY	Dth	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957
DOMINION GSS DEMAND	Dth	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403
DOMINION GSS CAPACITY	Dth	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304
DOMINION GSS-TE DEMAND	Dth	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337
DOMINION GSS-TE CAPACITY	Dth	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324
TENNESSEE FSMA DEMAND	Dth	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169
TENNESSEE FSMA CAPACITY	Dth	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343
TEXAS EASTERN SS-1 DEMAND	Dth	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802
TEXAS EASTERN SS-1 CAPACITY	Dth	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336
TEXAS EASTERN FSS-1 DEMAND	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TEXAS EASTERN FSS-1 CAPACITY	Dth	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720
STORAGE DELIVERY BILLING UNITS (DTH)													
ALGONQUIN FOR TETCO SS-1	Dth	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137
ALGONQUIN DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
ALGONQUIN SCT FOR SS-1	Dth	665	665	665	665	665	665	665	665	665	665	665	665
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	Dth	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739
ALGONQUIN SCT DELIVERY FOR GSS-TE	Dth	187	187	187	187	187	187	187	187	187	187	187	187
ALGONQUIN DELIVERY FOR GSS CONV	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
ALGONQUIN DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
DOMINION DELIVERY FOR GSS	Dth	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324
DOMINION DELIVERY FOR GSS CONV	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
TENNESSEE DELIVERY FOR GSS	Dth	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725
TENNESSEE DELIVERY FOR FSMA	Dth	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111
TETCO DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TETCO DELIVERY FOR GSS/GSS-TE	Dth	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377
TETCO DELIVERY FOR GSS-TE	Dth	538	538	538	538	538	538	538	538	538	538	538	538
TETCO DELIVERY FOR GSS-TE	Dth	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011
TETCO DELIVERY FOR GSS CONV	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
SUPPLIER FIXED COST BILLING UNITS													
DISTRIGAS NSB CALL PAYMENT Winter	Dth	[redacted]											
DISTRIGAS NSB CALL PAYMENT Summer	Dth												

REDACTED VERSION

		NOV	DEC	JAN-13	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	
							TOTAL COST							
PIPELINE FIXED COST DOLLARS														
ALGONQUIN AFT-E/AFT-1 DEMAND	$	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	
ALGONQUIN AFT-3 DEMAND	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
ALGONQUIN AFT-ES/1S DEMAND	$	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	
ALGONQUIN HUBLINE DEMAND	$	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	
ALGONQUIN HUBLINE DEMAND	$	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	
ALGONQUIN HUBLINE DEMAND	$	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	
ALGONQUIN EAST TO WEST DEMAND	$	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	
COLUMBIA FTS DEMAND	$	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	
DOMINION FTNN DEMAND	$	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	
IROQUOIS DEMAND	$	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	
NATIONAL FUEL DEMAND	$	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	
TENNESSEE FT-A DEMAND DRACUT	$	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	
TEXAS EASTERN CDS STX DEMAND M3	$	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	
TEXAS EASTERN CDS WLA DEMAND M3	$	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	
TEXAS EASTERN CDS ELA DEMAND M3	$	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	
TEXAS EASTERN CDS ETX DEMAND M3	$	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	
TEXAS EASTERN CDS 1-3 DEMAND M3	$	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	
TEXAS EASTERN FTS DEMAND	$	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	
TEXAS EASTERN SCT STX DEMAND M3	$	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	
TEXAS EASTERN SCT WLA DEMAND M3	$	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	
TEXAS EASTERN SCT ELA DEMAND M3	$	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	
TEXAS EASTERN SCT ETX DEMAND M3	$	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	
TEXAS EASTERN SCT 1-3 DEMAND M3	$	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	
TEXAS EASTERN SCT STX DEMAND M2	$	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	
TEXAS EASTERN SCT WLA DEMAND M2	$	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	
TEXAS EASTERN SCT ELA DEMAND M2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TEXAS EASTERN SCT ETX DEMAND M2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TEXAS EASTERN SCT 1-2 DEMAND M2	$	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	
TRANSCANADA DEMAND	$	$10,459	$10,808	$10,808	$9,762	$10,808	$10,459	$10,808	$10,459	$10,808	$10,808	$10,459	$10,808	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,923	$1,987	$1,987	$1,795	$1,987	$1,923	$1,987	$1,923	$1,987	$1,987	$1,923	$1,987	
TRANSCO DEMAND ZONE 3 TO 6.	$	$39	$41	$41	$37	$41	$39	$41	$39	$41	$41	$39	$41	
TRANSCO DEMAND ZONE 6	$	$4,442	$4,590	$4,590	$4,146	$4,590	$4,442	$4,590	$4,442	$4,590	$4,590	$4,442	$4,590	
UNION DEMAND	$	$2,429	$2,510	$2,510	$2,267	$2,510	$2,429	$2,510	$2,429	$2,510	$2,510	$2,429	$2,510	
WESTERLY LATERAL (Yankee)	$	[redacted]												
TOTAL PIPELINE DEMAND COSTS		**$2,939,236**	**$2,939,879**	**$2,938,539**	**$2,936,610**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$35,260,650**
STORAGE FIXED COST DOLLARS														
COLUMBIA FSS DEMAND	$	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	$3,840	
COLUMBIA FSS CAPACITY	$	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	
DOMINION GSS DEMAND	$	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	$21,424	
DOMINION GSS CAPACITY	$	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	
DOMINION GSS-TE DEMAND	$	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	$26,936	
DOMINION GSS-TE CAPACITY	$	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	
TENNESSEE FSMA DEMAND	$	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	$32,600	
TENNESSEE FSMA CAPACITY	$	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	$17,204	
TEXAS EASTERN SS-1 DEMAND	$	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	$81,515	
TEXAS EASTERN SS-1 CAPACITY	$	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	
TEXAS EASTERN FSS-1 DEMAND	$	$845	$845	$845	$845	$845	$845	$845	$845	$845	$845	$845	$845	
TEXAS EASTERN FSS-1 CAPACITY	$	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	
NATIONAL GRID LNG TANK LEASE PAYMENTS	$	[redacted]												
TOTAL STORAGE DEMAND COSTS	$	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$4,835,962**

REDACTED VERSION

STORAGE DELIVERY FIXED COSTS														
ALGONQUIN FOR TETCO SS-1	$	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	
ALGONQUIN DELIVERY FOR FSS-1	$	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	
ALGONQUIN SCT FOR SS-1	$	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	
ALGONQUIN SCT DELIVERY FOR GSS-TE	$	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	
ALGONQUIN DELIVERY FOR GSS CONV	$	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	
ALGONQUIN DELIVERY FOR FSS	$	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	
COLUMBIA DELIVERY FOR FSS	$	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	$15,033	
DOMINION DELIVERY FOR GSS	$	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	$22,914	
DOMINION DELIVERY FOR GSS CONV	$	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	$8,871	
TENNESSEE DELIVERY FOR GSS	$	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	$57,093	
TENNESSEE DELIVERY FOR FSMA	$	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	$34,901	
TETCO DELIVERY FOR FSS-1	$	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	$4,964	
TETCO DELIVERY FOR GSS/GSS-TE	$	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	$34,123	
TETCO DELIVERY FOR GSS-TE	$	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	
TETCO DELIVERY FOR GSS-TE	$	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	
TETCO DELIVERY FOR GSS CONV	$	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	
TOTAL STORAGE DELIVERY DEMAND COSTS		**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$5,090,738**
DISTRIGAS NSB CALL PAYMENT Winter	$	[redacted]												
DISTRIGAS NSB CALL PAYMENT Summer	$													
TOTAL SUPPLIER DEMAND COSTS														
TOTAL ALL DEMAND COSTS	$	**$3,885,211**	**$3,885,854**	**$3,884,514**	**$3,882,585**	**$3,884,514**	**$3,890,504**	**$3,891,147**	**$3,890,504**	**$3,891,147**	**$3,891,147**	**$3,890,504**	**$3,891,147**	**$46,658,779**

		NOV	DEC	JAN-13	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
Marketer Demand Charge Credits														
Capacity Release Volumes as of August 1, 2012														
Tennessee Dth		9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	9,499	
Algonquin	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	
Tetco STX/AGT	Dth	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	
Tetco WLA/AGT	Dth	8,499	8,499	8,499	8,499	8,499	8,499	8,499	8,499	8,499	8,499	8,499	8,499	
Tetco ELA/AGT	Dth	6,499	6,499	6,499	6,499	6,499	6,499	6,499	6,499	6,499	6,499	6,499	6,499	
Columbia/AGT	Dth	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	
Total		**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	**32,414**	
System Weighted Average cost per MMBtu		**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	**$17.0071**	
Total Demand Charge Credit		**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$6,615,235**
Demand Costs Net of Releases to Marketers	**$**	**$3,333,941**	**$3,334,584**	**$3,333,245**	**$3,331,316**	**$3,333,245**	**$3,339,235**	**$3,339,878**	**$3,339,235**	**$3,339,878**	**$3,339,878**	**$3,339,235**	**$3,339,878**	**$40,043,545**
TOTAL PIPELINE DEMANDS	**$**	**$2,939,236**	**$2,939,879**	**$2,938,539**	**$2,936,610**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$35,260,650**
TOTAL STORAGE FACILITIES DEMANDS	**$**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$402,997**	**$4,835,962**
TOTAL STORAGE DELIVERY DEMANDS	**$**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$424,228**	**$5,090,738**
TOTAL SUPPLIER DEMANDS	**$**	[redacted]												
Total All Demands	**$**	**$3,885,211**	**$3,885,854**	**$3,884,514**	**$3,882,585**	**$3,884,514**	**$3,890,504**	**$3,891,147**	**$3,890,504**	**$3,891,147**	**$3,891,147**	**$3,890,504**	**$3,891,147**	**$46,658,779**
Marketer Release Credits	**$**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$551,270**	**$6,615,235**
NGPMP credit		**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$383,333**	**$4,600,000**
Demand Net of Releases	**$**	**$2,950,608**	**$2,951,251**	**$2,949,911**	**$2,947,982**	**$2,949,911**	**$2,955,901**	**$2,956,544**	**$2,955,901**	**$2,956,544**	**$2,956,544**	**$2,955,901**	**$2,956,544**	**$35,443,545**

REDACTED VERSION

Storage Product Cost

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
WACOG INJECTIONS	$3.481	$3.912	$4.071	$4.023	$3.838	$3.829	$3.849	$3.871	$3.837	$3.824	$3.813	$3.846
Injection cost	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025
Total injection cost	$3.505	$3.936	$4.095	$4.047	$3.862	$3.854	$3.874	$3.895	$3.862	$3.848	$3.838	$3.871

COMBINED STORAGE	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	
Beginning Inv Vol	4,495,011	4,495,011	4,273,811	3,320,411	2,611,711	2,577,911	3,220,811	3,889,711	4,326,811	4,426,711	4,466,111	4,508,311	
Vol Withdrawn	0	221,200	953,400	708,700	33,800	0	0	0	0	0	0	29,500	1,946,600
Vol Injected	0	0	0	0	0	642,900	668,900	437,100	99,900	39,400	42,200	16,200	1,946,600
Begining Inv $ (virtual)	$17,309,838	$17,309,838	$16,458,019	$12,786,571	$10,057,438	$9,927,277	$12,404,846	$14,995,982	$16,698,544	$17,084,311	$17,235,932	$17,397,884	
$ Withdrawn (1)	$0	$1,629,965	$7,025,354	$5,222,224	$249,063	$0	$0	$0	$0	$0	$0	$113,843	$14,240,449
$ Injected	$0	$0	$0	$0	$0	$2,477,569	$2,591,136	$1,702,562	$385,767	$151,621	$161,953	$62,703	$7,533,310
Ending Vol	4,495,011	4,273,811	3,320,411	2,611,711	2,577,911	3,220,811	3,889,711	4,326,811	4,426,711	4,466,111	4,508,311	4,495,011	
Ending $	$17,309,838	$16,458,019	$12,786,571	$10,057,438	$9,927,277	$12,404,846	$14,995,982	$16,698,544	$17,084,311	$17,235,932	$17,397,884	$17,346,745	
Avg $/Mmbtu	$3.8509	$3.8509	$3.8509	$3.8509	$3.8509	$3.8515	$3.8553	$3.8593	$3.8594	$3.8593	$3.8591	$3.8591	
Withdrawal cost	**$0**	**$3,944**	**$28,628**	**$24,933**	**$467**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$338**	**$58,309**
Transportation cost	**$0**	**$11,455**	**$43,406**	**$23,401**	**$1,789**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$3,186**	**$83,237**
Costs allocated to fuel	**$0**	**$18,869**	**$102,434**	**$87,801**	**$3,466**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,158**	**$213,727**
Storage value Less fuel	**$0**	**$1,611,095**	**$6,922,920**	**$5,134,424**	**$245,598**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$112,685**	**$14,026,722**
Delivered Volumes	0	216,300	926,800	685,900	32,900	0	0	0	0	0	0	29,200	1,891,100
Hedge Amortization	$0	$778,146	$3,353,906	$2,493,091	$118,903	$0	$0	$0	$0	$0	$0	$0	$6,744,046

- amortization of hedges on injection gas
$6,744,046
(1) Includes Hedge Amortization
1,917,100 Withdrawal

REDACTED VERSION

Storage Withdrawal variable costs
2012-2013 GCR Storage estimate

Storage Withdrawals at Facility Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_501	0	45,300	177,000	119,100	7,600	0	0	0	0	0	0	11,300	360,300
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	14,200	20,800	0	0	0	0	0	0	0	0	7,700	42,700
GSS 300171	0	0	69,900	42,100	0	0	0	0	0	0	0	0	112,000
GSS-TE 600045	0	102,200	170,700	151,700	0	0	0	0	0	0	0	0	424,600
TETCO_400515	0	0	14,091	14,091	0	0	0	0	0	0	0	0	28,181
TETCO_400221	0	0	287,258	287,258	0	0	0	0	0	0	0	0	574,517
TETCO 400185	0	0	12,574	0	0	0	0	0	0	0	0	0	12,574
GSS 300169	0	0	55,700	48,200	0	0	0	0	0	0	0	0	103,900
COL FSS 9630	0	40,000	40,100	36,400	26,200	0	0	0	0	0	0	0	142,700
TENN_62918	0	19,500	95,000	0	0	0	0	0	0	0	0	10,500	125,000
TOTAL	0	221,200	943,123	698,849	33,800	0	0	0	0	0	0	29,500	1,926,472

STORAGE WITHDRAWAL PRICES												
Tennessee Withdrawal	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087
Dominion GSS Withdrawal	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193	$0.0193
Dominion GSS-TE Withdrawal	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244	$0.0244
Tetco SS-1 Withdrawal	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606	$0.0606
Tetco FSS-1 Withdrawal	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346
Columbia Withdrawal	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153

Withdrawal Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Withdrawal	$0	$564	$2,366	$1,036	$66	$0	$0	$0	$0	$0	$0	$190	$4,222
Dominion GSS Withdrawal	$0	$274	$2,826	$1,743	$0	$0	$0	$0	$0	$0	$0	$149	$4,991
Dominion GSS-TE Withdrawal	$0	$2,494	$4,165	$3,701	$0	$0	$0	$0	$0	$0	$0	$0	$10,360
Tetco SS-1 Withdrawal	$0	$0	$18,170	$17,408	$0	$0	$0	$0	$0	$0	$0	$0	$35,578
Tetco FSS-1 Withdrawal	$0	$0	$488	$488	$0	$0	$0	$0	$0	$0	$0	$0	$975
Columbia Withdrawal	$0	$612	$614	$557	$401	$0	$0	$0	$0	$0	$0	$0	$2,183
Total	$0	$3,944	$28,628	$24,933	$467	$0	$0	$0	$0	$0	$0	$338	$58,309

Storage Withdrawals at Gate Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_501	0	44,700	174,900	117,700	7,500	0	0	0	0	0	0	11,200	356,000
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	14,000	20,600	0	0	0	0	0	0	0	0	7,600	42,200
GSS 300171	0	0	68,300	41,100	0	0	0	0	0	0	0	0	109,400
GSS-TE 600045	0	99,600	166,400	147,800	0	0	0	0	0	0	0	0	413,800
TETCO_400515	0	0	13,400	13,400	0	0	0	0	0	0	0	0	26,800
TETCO_400221	0	0	284,300	284,300	0	0	0	0	0	0	0	0	568,600
TETCO 400185	0	0	12,400	0	0	0	0	0	0	0	0	0	12,400
GSS 300169	0	0	53,500	46,300	0	0	0	0	0	0	0	0	99,800
COL FSS 9630	0	38,800	39,100	35,300	25,400	0	0	0	0	0	0	0	138,600
TENN_62918	0	19,200	93,900	0	0	0	0	0	0	0	0	10,400	123,500
TOTAL	0	216,300	926,800	685,900	32,900	0	0	0	0	0	0	29,200	1,891,100

Storage Transportation Prices												
Tennessee Transportation	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091
Dominion Trans on Tetco/AGT	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148	$0.0148
Dominion Trans on DTI/Tetco/AGT	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400
Dominion Trans on Tennessee	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091	$0.1091
Dominion Trans on DTI/Tennessee	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343
Tetco SS-1 Trans	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130
Tetco FSS-1 Trans	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648	$0.0648
Columbia Trans	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382	$0.0382

Storage Transportation Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Transportation	$0	$6,971	$29,326	$12,841	$818	$0	$0	$0	$0	$0	$0	$2,357	$52,313
Dominion Trans on Tetco/AGT	$0	$1,474	$3,474	$2,796	$0	$0	$0	$0	$0	$0	$0	$0	$7,743
Dominion Trans on DTI/Tetco/AGT	$0	$0	$2,140	$1,852	$0	$0	$0	$0	$0	$0	$0	$0	$3,992
Dominion Trans on Tennseess	$0	$1,527	$2,247	$0	$0	$0	$0	$0	$0	$0	$0	$829	$4,604
Dominion Trans on DTI/Tennessee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tetco SS-1 Trans	$0	$0	$3,857	$3,696	$0	$0	$0	$0	$0	$0	$0	$0	$7,553
Tetco FSS-1 Trans	$0	$0	$868	$868	$0	$0	$0	$0	$0	$0	$0	$0	$1,737
Columbia Trans	$0	$1,482	$1,494	$1,348	$970	$0	$0	$0	$0	$0	$0	$0	$5,295
Total	$0	$11,455	$43,406	$23,401	$1,789	$0	$0	$0	$0	$0	$0	$3,186	$83,237
Total Variable	$0	$15,399	$72,034	$48,334	$2,256	$0	$0	$0	$0	$0	$0	$3,524	$141,546

REDACTED VERSION

National Grid
Rhode Island - Gas

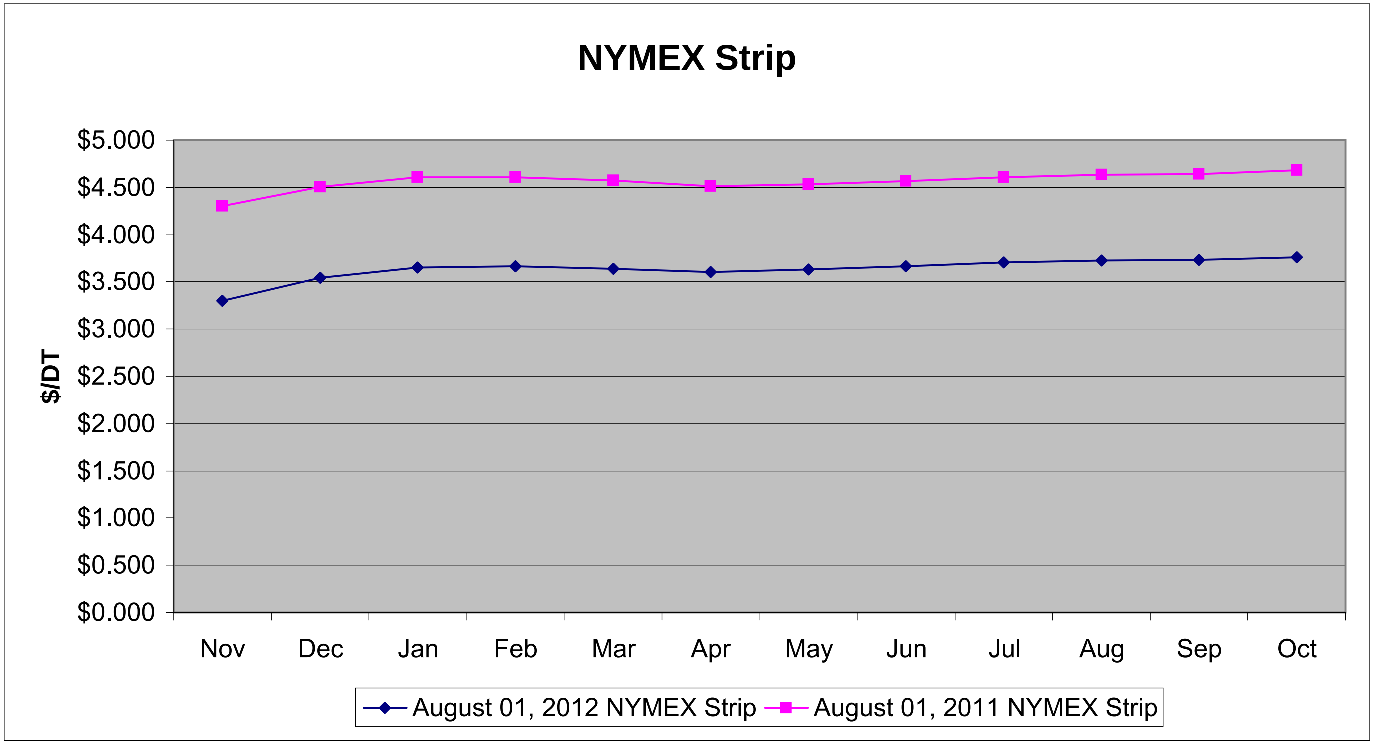
Attachment EDA-2
Redacted
Docket No. 4346
September 4, 2012

NATIONAL GRID - RI SERVICE AREA
NOVEMBER 2012 - OCTOBER 2013

LNG Estimate for 2012 - 2013

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
08/01/2012 NYMEX	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
Algonquin city-gates	$4.165	$5.880	$7.673	$6.669	$4.707	$4.047	$3.821	$3.923	$4.070	$4.091	$3.979	$4.100	
Trucking	[redacted]												
Basis NSB contract - Winter	[redacted]												
Delivered Cost NSB - Winter													
Basis NSB contract - Summer	[redacted]												
Delivered Cost NSB - Summer													
	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
Combined LNG Inv													
Beginning Inv Vol	888,000	869,200	778,100	715,500	679,600	660,100	641,300	777,000	888,100	868,600	849,100	887,900	
Vol Injected - winter	0	0	0	0	0	0	0	0	0	0	0	0	0
Vol Injected - summer	0	0	0	0	0	0	155,200	129,900	0	0	57,600	19,500	362,200
Vol Withdrawn	18,800	91,100	62,600	35,900	19,500	18,800	19,500	18,800	19,500	19,500	18,800	19,400	362,200
$ Begining Inv 11/1/12 = $5.6006	$4,973,333	$4,868,042	$4,357,827	$4,007,229	$3,806,168	$3,696,956	$3,591,665	$4,492,960	$5,243,279	$5,128,152	$5,013,026	$5,286,166	
$ Injected	$0	$0	$0	$0	$0	$0	$1,010,507	$859,029	$0	$0	$384,134	$132,405	$2,386,075
$ Withdrawn	$105,291	$510,215	$350,598	$201,062	$109,212	$105,291	$109,212	$108,710	$115,127	$115,127	$110,994	$115,499	$2,056,336
Ending Vol	869,200	778,100	715,500	679,600	660,100	641,300	777,000	888,100	868,600	849,100	887,900	888,000	
Ending $	$4,868,042	$4,357,827	$4,007,229	$3,806,168	$3,696,956	$3,591,665	$4,492,960	$5,243,279	$5,128,152	$5,013,026	$5,286,166	$5,303,072	
Avg $/Dth	[redacted]												
Newport													
Newport LNG Vol Vapor	0	0	0	0	0	0	0	0	0	0	0	0	
Avg $/Dth	[redacted]												
Total cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total All LNG Costs	**$105,291**	**$510,215**	**$350,598**	**$201,062**	**$109,212**	**$105,291**	**$109,212**	**$108,710**	**$115,127**	**$115,127**	**$110,994**	**$115,499**	**$2,056,336**

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 01, 2011 NYMEX Strip	**$4.303**	**$4.505**	**$4.607**	**$4.608**	**$4.575**	**$4.512**	**$4.532**	**$4.565**	**$4.606**	**$4.635**	**$4.644**	**$4.682**
August 01, 2012 NYMEX Strip	**$3.297**	**$3.540**	**$3.653**	**$3.664**	**$3.637**	**$3.607**	**$3.629**	**$3.665**	**$3.708**	**$3.729**	**$3.734**	**$3.762**



PRELIMINARY | **PRELIMINARY**

12 Month Forward Pricing

National Grid
Summary of Transportation Capacity Release
Pipeline Path Availability and Pricing
November 2012 - October 2013

Path to City Gate	As of 8/1/12 Existing Releases	Total Available	Remaining Available	Cost /Dth	New Credit/ Surcharge	Old Credit / Surcharge
Company Weighted Average				**$0.8601**		
Tennessee Zone 1	9,499	9,500	1	$1.1467	($0.2866)	($0.3232)
Algonquin @ Lambertville, NJ	2,714	2,714	0	$0.5559	$0.3042	$0.0949
Texas Eastern - South Texas Algonquin @ Lambertville, NJ	4,002	4,044	42	$1.3359	($0.4758)	($0.3755)
Texas Eastern - West La Algonquin @ Lambertville, NJ	8,499	8,500	1	$1.1297	($0.2696)	($0.1939)
Texas Eastern - East La Algonquin @ Lambertville, NJ	6,499	6,500	1	$1.0184	($0.1583)	$0.0033
Columbia (Maumee/Downington) at 5:1 ratio*	1,201	1,500	299	$0.5331	$0.3270	$0.3198
Totals:	32,414	32,758	344			

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

REDACTED VERSIONS

Gas Year 2012 - 2013
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	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	
TETCO M1 TO M3 DEMAND	$/Dth	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	
VARIABLE														
TETCO USAGE STX TO M3	$/Dth	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	$0.102	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/01/2012 NYMEX	$/Dth	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
BILLING UNITS														
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	4,082	4,085	4,085	4,085	4,085	4,082	4,082	4,082	4,082	4,082	4,082	4,082	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	4,082	4,085	4,085	4,085	4,085	4,082	4,082	4,082	4,082	4,082	4,082	4,082	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	4,082	4,085	4,085	4,085	4,085	4,082	4,082	4,082	4,082	4,082	4,082	4,082	
TETCO M1 TO M3 DEMAND	$/Dth	4,082	4,085	4,085	4,085	4,085	4,082	4,082	4,082	4,082	4,082	4,082	4,082	
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	133,035	140,062	140,062	126,508	140,062	133,035	137,470	133,035	137,470	137,470	133,035	137,470	1,628,714
TETCO USAGE STX TO M3	Dth	122,459	126,630	126,630	114,376	126,630	122,459	126,541	122,459	126,541	126,541	122,459	126,541	1,490,265
ALGONQUIN USAGE	Dth	121,320	125,364	125,364	113,232	125,364	121,320	125,364	121,320	125,364	125,364	121,320	125,364	1,476,060
DELIVERED VOLUMES	Dth	121,320	125,364	125,364	113,232	125,364	121,320	125,364	121,320	125,364	125,364	121,320	125,364	1,476,060
FUEL USE %														
TETCO STX TO M3 FUEL	%	7.95%	9.59%	9.59%	9.59%	9.59%	7.95%	7.95%	7.95%	7.95%	7.95%	7.95%	7.95%	
ALGONQUIN AFT-E FUEL	%	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
TRANSPORTATION COST														
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$	$27,778	$27,797	$27,797	$27,797	$27,797	$27,778	$27,778	$27,778	$27,778	$27,778	$27,778	$27,778	$333,412
TECCO WLA SUPPLY ZONE DEMAND	$	$11,532	$11,540	$11,540	$11,540	$11,540	$11,532	$11,532	$11,532	$11,532	$11,532	$11,532	$11,532	$138,411
TETCO ELA SUPPLY ZONE DEMAND	$	$9,695	$9,702	$9,702	$9,702	$9,702	$9,695	$9,695	$9,695	$9,695	$9,695	$9,695	$9,695	$116,363
TETCO M1 TO M3 DEMAND	$	$44,591	$44,623	$44,623	$44,623	$44,623	$44,591	$44,591	$44,591	$44,591	$44,591	$44,591	$44,591	$535,222
ALGONQUIN AFT-E DEMAND	$	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$290,057
VARIABLE														
TETCO USAGE STX TO M3	$	$12,503	$12,929	$12,929	$11,678	$12,929	$12,503	$12,920	$12,503	$12,920	$12,920	$12,503	$12,920	$152,156
ALGONQUIN USAGE	$	$1,577	$1,630	$1,630	$1,472	$1,630	$1,577	$1,630	$1,577	$1,630	$1,630	$1,577	$1,630	$19,189
PURCHASE COST	$	$425,313	$480,414	$495,540	$449,356	$494,000	$465,490	$484,443	$474,004	$497,365	$500,252	$484,115	$503,414	$5,753,707
TOTAL FIXED	$	$117,767	$117,833	$117,833	$117,833	$117,833	$117,767	$117,767	$117,767	$117,767	$117,767	$117,767	$117,767	$1,413,465
TOTAL VARIABLE	$	$439,394	$494,972	$510,099	$462,506	$508,558	$479,570	$498,993	$488,084	$511,915	$514,802	$498,195	$517,963	$5,925,051
DELIVERED COST AT NYMEX	$	$399,992	$443,789	$457,955	$414,882	$455,949	$437,601	$454,946	$444,638	$464,850	$467,482	$453,009	$471,619	$5,366,712
NET NON-GAS VARIABLE COST	$	$39,402	$51,184	$52,144	$47,624	$52,609	$41,969	$44,047	$43,447	$47,065	$47,319	$45,186	$46,344	$558,340
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.3248**	**$0.4083**	**$0.4159**	**$0.4206**	**$0.4197**	**$0.3459**	**$0.3514**	**$0.3581**	**$0.3754**	**$0.3775**	**$0.3725**	**$0.3697**	**$0.3783**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED VERSIONS

National Grid
Rhode Island - Gas

Gas Year 2012 - 2013
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	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	
TETCO M1 TO M3 DEMAND	$/Dth	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	
VARIABLE														
TETCO USAGE WLA TO M3	$/Dth	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	$0.098	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/01/2012 NYMEX	$/Dth	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
BILLING UNITS														
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	Dth	8,580	8,586	8,586	8,586	8,586	8,580	8,580	8,580	8,580	8,580	8,580	8,580	
TETCO ELA SUPPLY ZONE DEMAND	Dth	8,580	8,586	8,586	8,586	8,586	8,580	8,580	8,580	8,580	8,580	8,580	8,580	
TETCO M1 TO M3 DEMAND	Dth	8,580	8,586	8,586	8,586	8,586	8,580	8,580	8,580	8,580	8,580	8,580	8,580	
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	277,513	291,333	291,333	263,139	291,333	277,513	286,764	277,513	286,764	286,764	277,513	286,764	3,394,247
TETCO USAGE WLA TO M3	Dth	257,394	266,162	266,162	240,404	266,162	257,394	265,974	257,394	265,974	265,974	257,394	265,974	3,132,358
ALGONQUIN USAGE	Dth	255,000	263,500	263,500	238,000	263,500	255,000	263,500	255,000	263,500	263,500	255,000	263,500	3,102,500
DELIVERED VOLUMES	Dth	255,000	263,500	263,500	238,000	263,500	255,000	263,500	255,000	263,500	263,500	255,000	263,500	3,102,500
FUEL USE %														
TETCO WLA TO M3 FUEL	%	7.25%	8.64%	8.64%	8.64%	8.64%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
ALGONQUIN AFT-E FUEL	%	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
TRANSPORTATION COST														
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$	$24,238	$24,255	$24,255	$24,255	$24,255	$24,238	$24,238	$24,238	$24,238	$24,238	$24,238	$24,238	$290,924
TETCO ELA SUPPLY ZONE DEMAND	$	$20,377	$20,391	$20,391	$20,391	$20,391	$20,377	$20,377	$20,377	$20,377	$20,377	$20,377	$20,377	$244,582
TETCO M1 TO M3 DEMAND	$	$93,726	$93,792	$93,792	$93,792	$93,792	$93,726	$93,726	$93,726	$93,726	$93,726	$93,726	$93,726	$1,124,973
ALGONQUIN AFT-E DEMAND	$	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$50,805	$609,664
VARIABLE														
TETCO USAGE WLA TO M3	$	$25,199	$26,057	$26,057	$23,536	$26,057	$25,199	$26,039	$25,199	$26,039	$26,039	$25,199	$26,039	$306,658
ALGONQUIN USAGE	$	$3,315	$3,426	$3,426	$3,094	$3,426	$3,315	$3,426	$3,315	$3,426	$3,426	$3,315	$3,426	$40,333
PURCHASE COST	$	$908,857	$1,024,909	$1,047,341	$948,880	$1,042,680	$985,728	$1,024,894	$997,661	$1,048,409	$1,054,718	$1,020,972	$1,063,034	$12,168,083
TOTAL FIXED	$	$189,146	$189,244	$189,244	$189,244	$189,244	$189,146	$189,146	$189,146	$189,146	$189,146	$189,146	$189,146	$2,270,142
TOTAL VARIABLE	$	$937,371	$1,054,391	$1,076,824	$975,510	$1,072,163	$1,014,242	$1,054,359	$1,026,175	$1,077,873	$1,084,182	$1,049,486	$1,092,498	$12,515,073
DELIVERED VOLUMES AT NYMEX	$	$840,735	$932,790	$962,566	$872,032	$958,350	$919,785	$956,242	$934,575	$977,058	$982,592	$952,170	$991,287	$11,280,180
NET NON-GAS VARIABLE COST	$	$96,636	$121,601	$114,259	$103,478	$113,813	$94,457	$98,117	$91,600	$100,815	$101,591	$97,316	$101,211	$1,234,893
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.3790**	**$0.4615**	**$0.4336**	**$0.4348**	**$0.4319**	**$0.3704**	**$0.3724**	**$0.3592**	**$0.3826**	**$0.3855**	**$0.3816**	**$0.3841**	**$0.3980**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED VERSIONS

Gas Year 2012 - 2013
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	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	
TETCO M1 TO M3 DEMAND	$/Dth	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	$10.924	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	
VARIABLE														
TETCO USAGE ELA TO M3	$/Dth	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	$0.096	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/01/2012 NYMEX	$/Dth	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
BILLING UNITS														
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	Dth	6,561	6,566	6,566	6,566	6,566	6,561	6,561	6,561	6,561	6,561	6,561	6,561	
TETCO M1 TO M3 DEMAND	Dth	6,561	6,566	6,566	6,566	6,566	6,561	6,561	6,561	6,561	6,561	6,561	6,561	
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	211,532	221,740	221,740	200,281	221,740	211,532	218,583	211,532	218,583	218,583	211,532	218,583	2,585,962
TETCO USAGE ELA TO M3	Dth	196,831	203,535	203,535	183,838	203,535	196,831	203,392	196,831	203,392	203,392	196,831	203,392	2,395,333
ALGONQUIN USAGE	Dth	195,000	201,500	201,500	182,000	201,500	195,000	201,500	195,000	201,500	201,500	195,000	201,500	2,372,500
DELIVERED VOLUMES	Dth	195,000	201,500	201,500	182,000	201,500	195,000	201,500	195,000	201,500	201,500	195,000	201,500	2,372,500
FUEL USE %														
TETCO ELA TO M3 FUEL	%	6.95%	8.21%	8.21%	8.21%	8.21%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	
ALGONQUIN AFT-E FUEL	%	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
TRANSPORTATION COST														
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	$	$15,582	$15,593	$15,593	$15,593	$15,593	$15,582	$15,582	$15,582	$15,582	$15,582	$15,582	$15,582	$187,033
TETCO M1 TO M3 DEMAND	$	$71,673	$71,723	$71,723	$71,723	$71,723	$71,673	$71,673	$71,673	$71,673	$71,673	$71,673	$71,673	$860,273
ALGONQUIN AFT-E DEMAND	$	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$38,851	$466,214
VARIABLE														
TETCO USAGE ELA TO M3	$	$18,896	$19,539	$19,539	$17,648	$19,539	$18,896	$19,526	$18,896	$19,526	$19,526	$18,896	$19,526	$229,952
ALGONQUIN USAGE	$	$2,535	$2,620	$2,620	$2,366	$2,620	$2,535	$2,620	$2,535	$2,620	$2,620	$2,535	$2,620	$30,843
PURCHASE COST	$	$687,267	$774,317	$800,260	$724,218	$795,826	$750,727	$780,560	$766,380	$797,828	$803,293	$777,592	$809,632	$9,267,900
TOTAL FIXED	$	$126,106	$126,168	$126,168	$126,168	$126,168	$126,106	$126,106	$126,106	$126,106	$126,106	$126,106	$126,106	$1,513,520
TOTAL VARIABLE	$	$708,698	$796,476	$822,419	$744,232	$817,985	$772,158	$802,705	$787,811	$819,973	$825,438	$799,022	$831,777	$9,528,695
DELIVERED VOLUMES AT NYMEX	$	$642,915	$713,310	$736,080	$666,848	$732,856	$703,365	$731,244	$714,675	$747,162	$751,394	$728,130	$758,043	$8,626,020
NET NON-GAS VARIABLE COST	$	$65,783	$83,166	$86,340	$77,384	$85,129	$68,793	$71,462	$73,136	$72,811	$74,044	$70,892	$73,734	$902,675
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.3373**	**$0.4127**	**$0.4285**	**$0.4252**	**$0.4225**	**$0.3528**	**$0.3546**	**$0.3751**	**$0.3613**	**$0.3675**	**$0.3636**	**$0.3659**	**$0.3805**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED VERSIONS

Gas Year 2012 - 2013
MAUMEE/DOWNINGTON COLUMBIA PATH TO CITY GATE
CITY GATE DELIVERED MDQ = 1,500

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
UNIT PRICING														
FIXED														
COLUMBIA FTS DEMAND	$/Dth	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	$6.077	
ALGONQUIN DEMAND	$/Dth	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	
VARIABLE														
COLUMBIA USAGE	$/Dth	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/01/2012 NYMEX	$/Dth	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
SUPPLY BASIS MAUMEE	$/Dth	[redacted]												
SUPPLY BASIS DOWNINGTON	$/Dth													
NET COST AFTER BASIS MAUMEE	$/Dth													
NET COST AFTER BASIS DOWNINGTON	$/Dth													
BILLING UNITS														
FIXED														
COLUMBIA FTS DEMAND	Dth	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	
ALGONQUIN DEMAND	Dth	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	18,000
VARIABLE														
PURCHASE VOLUMES MAUMEE	Dth	38,610	39,141	39,141	35,354	39,141	37,852	39,114	37,852	39,114	39,114	37,852	39,114	
PURCHASE VOLUMES DOWNINGTON	Dth	7,722	7,828	7,828	7,071	7,828	7,570	7,823	7,570	7,823	7,823	7,570	7,823	
COLUMBIA USAGE	Dth	45,422	46,970	46,970	42,424	46,970	45,422	46,937	45,422	46,937	46,937	45,422	46,937	
ALGONQUIN USAGE	Dth	45,000	46,500	46,500	42,000	46,500	45,000	46,500	45,000	46,500	46,500	45,000	46,500	
DELIVERED VOLUMES MAUMEE	Dth	37,500	38,750	38,750	35,000	38,750	37,500	38,750	37,500	38,750	38,750	37,500	38,750	456,250
DELIVERED VOLUMES DOWNINGTON	Dth	7,500	7,750	7,750	7,000	7,750	7,500	7,750	7,500	7,750	7,750	7,500	7,750	91,250
FUEL USE %														
COLUMBIA FUEL	%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	1.96%	
ALGONQUIN AFT-E FUEL	%	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
TRANSPORTATION COST														
FIXED														
COLUMBIA FTS DEMAND	$	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$9,298	$111,576
ALGONQUIN DEMAND	$	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$8,966	$107,588
VARIABLE														
COLUMBIA USAGE	$	$1,154	$1,193	$1,193	$1,078	$1,193	$1,154	$1,192	$1,154	$1,192	$1,192	$1,154	$1,192	$14,040
ALGONQUIN USAGE	$	$585	$605	$605	$546	$605	$585	$605	$585	$605	$605	$585	$605	$7,118
PURCHASE COST MAUMEE	$	$127,606	$138,756	$143,179	$129,606	$142,044	$137,744	$142,804	$139,182	$145,112	$145,542	$140,658	$146,051	$1,678,285
PURCHASE COST DOWNINGTON	$	$27,066	$32,816	$37,169	$31,387	$30,053	$28,328	$29,312	$28,639	$30,165	$30,329	$28,707	$29,938	$363,907
TOTAL FIXED	$	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$18,264	$219,164
TOTAL VARIABLE	$	$156,410	$173,370	$182,146	$162,617	$173,895	$167,811	$173,913	$169,559	$177,073	$177,668	$171,104	$177,785	$2,063,350
DELIVERED VOLUMES AT NYMEX	$	$148,365	$164,610	$169,865	$153,888	$169,121	$162,315	$168,749	$164,925	$172,422	$173,399	$168,030	$174,933	$1,990,620
NET NON-GAS VARIABLE COST	$	$8,045	$8,760	$12,281	$8,729	$4,774	$5,496	$5,164	$4,634	$4,651	$4,269	$3,074	$2,852	$72,730
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.1788**	**$0.1884**	**$0.2641**	**$0.2078**	**$0.1027**	**$0.1221**	**$0.1111**	**$0.1030**	**$0.1000**	**$0.0918**	**$0.0683**	**$0.0613**	**$0.1328**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2012 - 2013
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	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	$22.552	
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$/Dth	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	$0.274	
08/01/2012 NYMEX	$/Dth	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
						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	295,367	305,213	305,213	275,676	305,213	295,367	305,213	295,367	305,213	305,213	295,367	305,213	3,593,637
TENNESSE ZONE 1 TO 6 USAGE	Dth	285,000	294,500	294,500	266,000	294,500	285,000	294,500	285,000	294,500	294,500	285,000	294,500	3,467,500
DELIVERED VOLUMES	Dth	285,000	294,500	294,500	266,000	294,500	285,000	294,500	285,000	294,500	294,500	285,000	294,500	3,467,500
						FUEL USE %								
TENNESSEE ZONE 1 TO 6 FUEL	%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	
						TRANSPORTATION COST								
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$2,570,951
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$	$78,119	$80,722	$80,722	$72,911	$80,722	$78,119	$80,722	$78,119	$80,722	$80,722	$78,119	$80,722	$950,442
PURCHASE COST	$	$990,367	$1,061,531	$1,102,124	$1,006,770	$1,114,943	$1,075,728	$1,110,060	$1,070,411	$1,123,184	$1,125,320	$1,122,101	$1,159,504	$13,062,042
TOTAL FIXED	$	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$214,246	$2,570,951
TOTAL VARIABLE	$	$1,068,485	$1,142,253	$1,182,847	$1,079,680	$1,195,665	$1,153,847	$1,190,782	$1,148,530	$1,203,906	$1,206,043	$1,200,219	$1,240,227	$14,012,484
DELIVERED VOLUMES AT NYMEX	$	$939,645	$1,042,530	$1,075,809	$974,624	$1,071,097	$1,027,995	$1,068,741	$1,044,525	$1,092,006	$1,098,191	$1,064,190	$1,107,909	$12,607,260
NET NON-GAS VARIABLE COST	$	$128,840	$99,723	$107,038	$105,056	$124,569	$125,852	$122,042	$104,005	$111,900	$107,852	$136,029	$132,318	$1,405,224
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.4521**	**$0.3386**	**$0.3635**	**$0.3949**	**$0.4230**	**$0.4416**	**$0.4144**	**$0.3649**	**$0.3800**	**$0.3662**	**$0.4773**	**$0.4493**	**$0.4053**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED VERSIONS

Gas Year 2012 - 2013
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	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	
VARIABLE														
ALGONQUIN AFT-E USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/01/2012 NYMEX	$/Dth	$3.297	$3.540	$3.653	$3.664	$3.637	$3.607	$3.629	$3.665	$3.708	$3.729	$3.734	$3.762	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
						BILLING UNITS								
FIXED														
ALGONQUIN AFT-E DEMAND	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	32,568
VARIABLE														
PURCHASE VOLUMES	Dth	82,184	84,984	84,984	76,760	84,984	82,184	84,924	82,184	84,924	84,924	82,184	84,924	1,000,144
ALGONQUIN AFT-E USAGE	Dth	81,420	84,134	84,134	75,992	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	990,610
DELIVERED VOLUMES	Dth	81,420	84,134	84,134	75,992	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	990,610
						FUEL USE %								
ALGONQUIN AFT-E FUEL	%	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
						TRANSPORTATION COST								
FIXED														
ALGONQUIN AFT-E DEMAND	$	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$194,662
VARIABLE														
ALGONQUIN AFT-E USAGE	$	$1,058	$1,094	$1,094	$988	$1,094	$1,058	$1,094	$1,058	$1,094	$1,094	$1,058	$1,094	$12,878
PURCHASE COST	$	$288,056	$356,252	$403,503	$340,736	$326,253	$307,534	$318,209	$310,903	$327,466	$329,250	$311,643	$325,003	$3,944,809
TOTAL FIXED	$	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$194,662
TOTAL VARIABLE	$	$289,114	$357,346	$404,597	$341,724	$327,347	$308,592	$319,303	$311,962	$328,560	$330,343	$312,701	$326,097	$3,957,687
DELIVERED VOLUMES AT NYMEX	$	$268,442	$297,834	$307,342	$278,435	$305,995	$293,682	$305,322	$298,404	$311,969	$313,736	$304,022	$316,512	$3,601,695
NET NON-GAS VARIABLE COST	$	$20,673	$59,512	$97,256	$63,289	$21,351	$14,910	$13,981	$13,557	$16,591	$16,608	$8,679	$9,585	$355,992
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.2539**	**$0.7073**	**$1.1560**	**$0.8328**	**$0.2538**	**$0.1831**	**$0.1662**	**$0.1665**	**$0.1972**	**$0.1974**	**$0.1066**	**$0.1139**	**$0.3594**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED VERSION

National Grid
Rhode Island - Gas

Attachment EDA-4
Redacted
Docket No. 4346
September 4, 2012

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2012 - 2013 GCR PROJECTED PRICES**

August 1, 2012 **UNIT PRICES**

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
		2012		2013									
PIPELINE FIXED COST UNIT PRICES													
ALGONQUIN AFT-E/AFT-1 DEMAND	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554	$10.7554
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909
ALGONQUIN HUBLINE DEMAND	$/Dth	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583	$11.5583
ALGONQUIN HUBLINE DEMAND	$/Dth	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958	$6.9958
ALGONQUIN HUBLINE DEMAND	$/Dth	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920	$6.9920
ALGONQUIN EAST TO WEST DEMAND	$/Dth	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341	$8.4341
COLUMBIA FTS DEMAND	$/Dth	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770	$6.0770
DOMINION FTNN DEMAND	$/Dth	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040	$4.3040
IROQUOIS DEMAND	$/Dth	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971	$6.5971
NATIONAL FUEL DEMAND	$/Dth	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617	$3.9617
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587	$22.6587
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522	$22.5522
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$/Dth	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365	$22.7365
TENNESSEE FT-A DEMAND DRACUT	$/Dth	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846	$4.8846
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396	$7.4396
TEXAS EASTERN CDS STX DEMAND M3	$/Dth	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050	$6.8050
TEXAS EASTERN CDS WLA DEMAND M3	$/Dth	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250	$2.8250
TEXAS EASTERN CDS ELA DEMAND M3	$/Dth	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750
TEXAS EASTERN CDS ETX DEMAND M3	$/Dth	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890
TEXAS EASTERN CDS 1-3 DEMAND M3	$/Dth	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240	$10.9240
TEXAS EASTERN FTS DEMAND	$/Dth	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510	$5.3510
TEXAS EASTERN SCT STX DEMAND M3	$/Dth	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220
TEXAS EASTERN SCT WLA DEMAND M3	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
TEXAS EASTERN SCT ELA DEMAND M3	$/Dth	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500
TEXAS EASTERN SCT ETX DEMAND M3	$/Dth	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760
TEXAS EASTERN SCT 1-3 DEMAND M3	$/Dth	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710	$4.3710
TEXAS EASTERN SCT STX DEMAND M2	$/Dth	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220
TEXAS EASTERN SCT WLA DEMAND M2	$/Dth	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300	$1.1300
TEXAS EASTERN SCT ELA DEMAND M2	$/Dth	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500
TEXAS EASTERN SCT ETX DEMAND M2	$/Dth	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760
TEXAS EASTERN SCT 1-2 DEMAND M2	$/Dth	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290	$3.3290
TRANSCANADA DEMAND	$/Dth	$10.3350	$10.6795	$10.6795	$9.6460	$10.6795	$10.3350	$10.6795	$10.3350	$10.6795	$10.6795	$10.3350	$10.6795
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645	$0.4645
TRANSCO DEMAND ZONE 3 TO 6	$/Dth	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379	$0.4379
TRANSCO DEMAND ZONE 6	$/Dth	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194
UNION DEMAND	$/Dth	$2.3700	$2.4490	$2.4490	$2.2120	$2.4490	$2.3700	$2.4490	$2.3700	$2.4490	$2.4490	$2.3700	$2.4490

REDACTED VERSION

National Grid
Rhode Island - Gas

Attachment EDA-4
Redacted
Docket No. 4346
September 4, 2012

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2012 - 2013 GCR PROJECTED PRICES**

August 1, 2012

PIPELINE FIXED COST BILLING UNITS		**UNIT PRICES** NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
ALGONQUIN AFT-E/AFT-1 DEMAND	DTH	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285
ALGONQUIN AFT-3 DEMAND	DTH	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	DTH	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079
ALGONQUIN HUBLINE DEMAND	DTH	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
ALGONQUIN HUBLINE DEMAND	DTH	500	500	500	500	500	500	500	500	500	500	500	500
ALGONQUIN HUBLINE DEMAND	DTH	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
ALGONQUIN EAST TO WEST DEMAND	Dth	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
COLUMBIA FTS DEMAND	DTH	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
DOMINION FTNN DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
IROQUOIS DEMAND	DTH	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NATIONAL FUEL DEMAND	DTH	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
TENNESSEE FT-A DEMAND ZONE 0 TO 6	DTH	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	DTH	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500
TENNESSEE FT-A DEMAND ZONE 0 TO 6	DTH	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	DTH	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	DTH	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
TENNESSEE FT-A DEMAND DRACUT	DTH	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TENNESSEE FT-A DEMAND ZONE 5 TO 6	DTH	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067
TEXAS EASTERN CDS STX DEMAND M3	DTH	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN CDS WLA DEMAND M3	DTH	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN CDS ELA DEMAND M3	DTH	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN CDS ETX DEMAND M3	DTH	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TEXAS EASTERN CDS 1-3 DEMAND M3	DTH	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TEXAS EASTERN FTS DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
TEXAS EASTERN SCT STX DEMAND M3	DTH	571	571	571	571	571	571	571	571	571	571	571	571
TEXAS EASTERN SCT WLA DEMAND M3	DTH	648	648	648	648	648	648	648	648	648	648	648	648
TEXAS EASTERN SCT ELA DEMAND M3	DTH	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TEXAS EASTERN SCT ETX DEMAND M3	DTH	329	329	329	329	329	329	329	329	329	329	329	329
TEXAS EASTERN SCT 1-3 DEMAND M3	DTH	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TEXAS EASTERN SCT STX DEMAND M2	DTH	401	401	401	401	401	401	401	401	401	401	401	401
TEXAS EASTERN SCT WLA DEMAND M2	DTH	455	455	455	455	455	455	455	455	455	455	455	455
TEXAS EASTERN SCT ELA DEMAND M2	DTH	831	831	831	831	831	831	831	831	831	831	831	831
TEXAS EASTERN SCT ETX DEMAND M2	DTH	231	231	231	231	231	231	231	231	231	231	231	231
TEXAS EASTERN SCT 1-2 DEMAND M2	DTH	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474
TRANSCANADA DEMAND	DTH	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
TRANSCO DEMAND ZONE 2 TO 6	DTH	4,140	4,278	4,278	3,864	4,278	4,140	4,278	4,140	4,278	4,278	4,140	4,278
TRANSCO DEMAND ZONE 3 TO 6	DTH	90	93	93	84	93	90	93	90	93	93	90	93
TRANSCO DEMAND ZONE 6	DTH	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
UNION DEMAND	DTH	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025

REDACTED VERSION

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2012 - 2013 GCR PROJECTED PRICES**

August 1, 2012					**UNIT PRICES**									
		NOV	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	
PIPELINE FIXED COST DOLLARS														
ALGONQUIN AFT-E/AFT-1 DEMAND	$	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	$521,711	
ALGONQUIN AFT-3 DEMAND	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
ALGONQUIN AFT-ES/1S DEMAND	$	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	$9,752	
ALGONQUIN HUBLINE DEMAND	$	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	
ALGONQUIN HUBLINE DEMAND	$	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	
ALGONQUIN HUBLINE DEMAND	$	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	
ALGONQUIN EAST TO WEST DEMAND	$	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	$84,341	
COLUMBIA FTS DEMAND	$	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	$288,384	
DOMINION FTNN DEMAND	$	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	$2,311	
IROQUOIS DEMAND	$	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	
NATIONAL FUEL DEMAND	$	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	$4,663	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	$79,305	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	$147,282	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	$135,809	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	$300,237	
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$	$263,743	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	$73,269	
TENNESSEE FT-A DEMAND DRACUT	$	$73,269	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	$15,378	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$15,378	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	
TEXAS EASTERN CDS STX DEMAND M3	$	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	
TEXAS EASTERN CDS WLA DEMAND M3	$	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	
TEXAS EASTERN CDS ELA DEMAND M3	$	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	
TEXAS EASTERN CDS ETX DEMAND M3	$	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	
TEXAS EASTERN CDS 1-3 DEMAND M3	$	$501,783	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	
TEXAS EASTERN FTS DEMAND	$	$2,873	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	$501,783	
TEXAS EASTERN SCT STX DEMAND M3	$	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	
TEXAS EASTERN SCT WLA DEMAND M3	$	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	
TEXAS EASTERN SCT ELA DEMAND M3	$	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	
TEXAS EASTERN SCT ETX DEMAND M3	$	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	
TEXAS EASTERN SCT 1-3 DEMAND M3	$	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	$9,175	
TEXAS EASTERN SCT STX DEMAND M2	$	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	
TEXAS EASTERN SCT WLA DEMAND M2	$	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	
TEXAS EASTERN SCT ELA DEMAND M2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TEXAS EASTERN SCT ETX DEMAND M2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TEXAS EASTERN SCT 1-2 DEMAND M2	$	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	$4,907	
TRANSCANADA DEMAND	$	$10,459	$10,808	$10,808	$9,762	$10,808	$10,459	$10,808	$10,459	$10,808	$10,808	$10,459	$10,808	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,923	$1,987	$1,987	$1,795	$1,987	$1,923	$1,987	$1,923	$1,987	$1,987	$1,923	$1,987	
TRANSCO DEMAND ZONE 3 TO 6	$	$39	$41	$41	$37	$41	$39	$41	$39	$41	$41	$39	$41	
TRANSCO DEMAND ZONE 6	$	$4,442	$4,590	$4,590	$4,146	$4,590	$4,442	$4,590	$4,442	$4,590	$4,590	$4,442	$4,590	
UNION DEMAND	$	$2,429	$2,510	$2,510	$2,267	$2,510	$2,429	$2,510	$2,429	$2,510	$2,510	$2,429	$2,510	
WESTERLY LATERAL (Yankee)	$	[redacted]												
	$	**$2,939,236**	**$2,939,879**	**$2,938,539**	**$2,936,610**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$35,260,650**
TOTAL PIPELINE FIXED DEMAND CHARGES		**$2,939,236**	**$2,939,879**	**$2,938,539**	**$2,936,610**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$2,938,539**	**$2,937,896**	**$2,938,539**	**$35,260,650**
TOTAL DEMAND UNITS DTH		5,340,825	5,551,046	5,551,046	5,013,848	5,551,046	5,340,825	5,486,659	4,854,210	5,016,017	5,016,017	4,854,210	5,486,659	63,062,408
100% LOAD FACTOR UNIT VALUE $/DTH														[redacted]
Average rate per unit per month														
AVERAGE SYSTEM VARIABLE UNIT VALUE $/DTH														
Marketer Reconciliation 2010/11 & 2011/12														$374,462
Marketer Demand Units DTH		972,420	1,004,834	1,004,834	907,592	1,004,834	972,420	1,004,834	972,420	1,004,834	1,004,834	972,420	1,004,834	11,831,110
100% LOAD FACTOR UNIT VALUE $/DTH														[redacted]
TOTAL AVERAGE SYSTEM UNIT VALUE $/DTH														[redacted]

REDACTED VERSION

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV 2012	DEC 2012	JAN 2013	FEB 2013	MAR 2013	APR 2013	MAY 2013	JUN 2013	JUL 2013	AUG 2013	SEP 2013	OCT 2013	Total/Average
Forecast Demand													
RI Sales GCR	2,223,400	3,797,000	4,509,900	3,856,200	3,413,900	2,117,600	1,259,500	749,200	610,400	608,200	661,700	1,269,600	25,076,600
Total Demand	2,223,400	3,797,000	4,509,900	3,856,200	3,413,900	2,117,600	1,259,500	749,200	610,400	608,200	661,700	1,269,600	25,076,600
Storage Injections													
TENN 501	0	0	0	0	0	118,800	122,700	118,800	0	0	0	0	360,300
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	0	0	0	0	21,000	21,700	0	0	0	0	0	42,700
GSS 300171	0	0	0	0	0	15,800	16,200	15,700	16,200	16,200	15,700	16,200	112,000
GSSTE 600045	0	0	0	0	0	187,800	194,000	42,800	0	0	0	0	424,600
TETCO 400515	0	0	0	0	0	8,700	9,000	8,700	2,000	0	0	0	28,400
TETCO 400221	0	0	0	0	0	181,800	187,800	181,800	42,600	0	0	0	594,000
TETCO 400185	0	0	0	0	0	8,000	5,000	0	0	0	0	0	13,000
GSS 300169	0	0	0	0	0	29,200	29,100	28,100	17,500	0	0	0	103,900
COL FSS 9630	0	0	0	0	0	30,600	40,800	0	21,600	23,200	26,500	0	142,700
TENN 62918	0	0	0	0	0	41,200	42,600	41,200	0	0	0	0	125,000
Total Underground Storage	0	0	0	0	0	642,900	668,900	437,100	99,900	39,400	42,200	16,200	1,946,600
LNG PROV	0	0	0	0	0	0	107,100	120,400	0	0	35,800	12,100	275,400
LNG VALLEY	0	0	0	0	0	0	19,900	5,000	0	0	9,400	3,200	37,500
LNG EXETER	0	0	0	0	0	0	28,200	4,500	0	0	12,400	4,200	49,300
Total LNG Injection	0	0	0	0	0	0	155,200	129,900	0	0	57,600	19,500	362,200
Total Injections	0	0	0	0	0	642,900	824,100	567,000	99,900	39,400	99,800	35,700	2,308,800
Delivered Firm Sales Supply													
.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENN CONX	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	4,234,000
TENN ZONE 0	56,252	183,396	162,135	180,085	122,567	107,993	60,699	39,341	0	0	0	0	912,470
TENN ZONE 1	117,048	381,604	337,365	374,715	255,033	224,707	126,301	81,859	0	0	0	0	1,898,630
TENN NIAGARA	0	3,200	0	0	0	32,000	0	0	0	0	0	0	35,200
TENN DRACUT	0	35,000	0	0	0	0	19,200	0	0	0	0	0	54,200
COL MAUMEE	762,400	1,173,100	1,172,900	1,059,400	1,172,900	774,600	82,400	102,800	1,700	0	0	41,900	6,344,100
COL BROADRUN	291,400	300,900	300,800	271,700	300,800	291,600	301,400	291,400	251,300	252,500	291,600	301,100	3,446,500
TRANSCO Z2	3,915	4,013	4,013	3,621	0	0	0	0	0	0	0	0	15,562
TRANSCO Z3	85	87	87	79	0	0	0	0	0	0	0	0	338
TETCO ELA	0	230,267	326,736	260,657	0	164,378	168,230	105,658	29,856	6,177	5,986	6,177	1,304,123
TETCO ETX	0	68,982	97,881	78,086	0	49,243	50,397	31,652	8,944	1,850	1,793	1,850	390,681
TETCO STX	0	102,816	145,890	116,385	0	73,396	75,116	47,177	13,331	2,758	2,673	2,758	582,300
TETCO WLA	0	158,251	224,549	179,136	0	112,969	115,615	72,613	20,518	4,245	4,114	4,245	896,256
TETCO to B&W - SCT	0	25,604	36,331	28,983	0	18,278	18,706	11,748	3,320	687	666	687	145,010
TETCO - NF - TRANSCO	0	11,283	16,011	12,773	0	8,055	8,243	5,177	1,463	303	293	303	63,904
TETCO - DTI - TETCO	0	6,697	9,502	7,581	0	4,781	4,893	3,073	868	180	174	180	37,928
M3 DELIVERED	595,600	304,600	203,700	125,100	1,119,700	531,500	518,400	27,000	0	0	29,800	518,400	3,973,800
HUBLINE	0	109,000	92,100	83,100	0	0	0	0	0	0	0	0	284,200
COL EAGLE	0	0	0	0	0	0	0	0	0	0	0	0	0
COL DOWNINGTOWN	0	0	0	0	0	0	0	0	0	0	0	0	0
ANE II - DAWN-TENN	30,000	31,000	31,000	28,000	31,000	0	0	0	0	0	0	0	151,000
DISTRIGAS NSB Winter	0	0	0	0	0	0	0	0	0	0	0	0	0
DISTRIGAS NSB Summer	0	0	0	0	0	0	155,000	129,900	0	0	57,700	19,400	362,000
NEWPORT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0
SPOT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

REDACTED VERSION

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
Non LNG Liquid take	2,204,700	3,489,400	3,520,600	3,134,200	3,361,600	2,741,500	1,909,200	1,167,500	690,900	628,300	685,100	1,237,200	24,770,200
LNG Liquid take	0	0	0	0	0	0	155,000	129,900	0	0	57,700	19,400	362,000
Total take	2,204,700	3,489,400	3,520,600	3,134,200	3,361,600	2,741,500	2,064,200	1,297,400	690,900	628,300	742,800	1,256,600	25,132,200
Storage Withdrawals													
TENN 501	0	44,700	174,900	117,700	7,500	0	0	0	0	0	0	11,200	356,000
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	14,000	20,600	0	0	0	0	0	0	0	0	7,600	42,200
GSS 300171	0	0	68,300	41,100	0	0	0	0	0	0	0	0	109,400
GSSTE 600045	0	99,600	166,400	147,800	0	0	0	0	0	0	0	0	413,800
TETCO 400515	0	0	13,400	13,400	0	0	0	0	0	0	0	0	26,800
TETCO 400221	0	0	284,300	284,300	0	0	0	0	0	0	0	0	568,600
TETCO 400185	0	0	12,400	0	0	0	0	0	0	0	0	0	12,400
GSS 300169	0	0	53,500	46,300	0	0	0	0	0	0	0	0	99,800
COL FSS 9630	0	38,800	39,100	35,300	25,400	0	0	0	0	0	0	0	138,600
TENN 62918	0	19,200	93,900	0	0	0	0	0	0	0	0	10,400	123,500
LNG PROV	11,700	83,700	55,100	29,300	12,100	11,700	12,100	11,700	12,100	12,100	11,700	12,100	275,400
LNG VALLEY	3,100	3,200	3,200	2,800	3,200	3,100	3,200	3,100	3,200	3,200	3,100	3,100	37,500
LNG EXETER	4,000	4,200	4,300	3,800	4,200	4,000	4,200	4,000	4,200	4,200	4,000	4,200	49,300
Total Withdrawal Delivered	18,800	307,400	989,400	721,800	52,400	18,800	19,500	18,800	19,500	19,500	18,800	48,600	2,253,300
Total Storage withdrawal	0	216,300	926,800	685,900	32,900	0	0	0	0	0	0	29,200	1,891,100
Total Peaking withdrawal	18,800	91,100	62,600	35,900	19,500	18,800	19,500	18,800	19,500	19,500	18,800	19,400	362,200
Total Supply	**2,223,500**	**3,796,800**	**4,510,000**	**3,856,000**	**3,414,000**	**2,760,300**	**1,928,700**	**1,186,300**	**710,400**	**647,800**	**703,900**	**1,285,800**	**27,023,500**
Storage withdrawals at Storage Facilty													
TENN 501	0	45,300	177,000	119,100	7,600	0	0	0	0	0	0	11,300	360,300
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	14,200	20,800	0	0	0	0	0	0	0	0	7,700	42,700
GSS 300171	0	0	69,900	42,100	0	0	0	0	0	0	0	0	112,000
GSSTE 600045	0	102,200	170,700	151,700	0	0	0	0	0	0	0	0	424,600
TETCO 400515	0	0	14,200	14,200	0	0	0	0	0	0	0	0	28,400
TETCO 400221	0	0	297,000	297,000	0	0	0	0	0	0	0	0	594,000
TETCO 400185	0	0	13,000	0	0	0	0	0	0	0	0	0	13,000
GSS 300169	0	0	55,700	48,200	0	0	0	0	0	0	0	0	103,900
COL FSS 9630	0	40,000	40,100	36,400	26,200	0	0	0	0	0	0	0	142,700
TENN 62918	0	19,500	95,000	0	0	0	0	0	0	0	0	10,500	125,000
	0	221,200	953,400	708,700	33,800	0	0	0	0	0	0	29,500	1,946,600

REDACTED VERSION

National Grid
Rhode Island - Gas

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
08/01/2012 NYMEX	**$3.297**	**$3.540**	**$3.653**	**$3.664**	**$3.637**	**$3.607**	**$3.629**	**$3.665**	**$3.708**	**$3.729**	**$3.734**	**$3.762**	
TENNESSEE CONNEXION													
Basis	[redacted]												
usage to Zn 6	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
fuel to Zn 6	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	
Total Delivered	[redacted]												
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	$0.3142	
fuel	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	
Total Delivered	[redacted]												
TENNESSEE ZN 1													
Basis	[redacted]												
usage to Zn 6	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	$0.2741	
fuel to Zn 6	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	
Total Delivered	[redacted]												
TENNESSEE DRACUT													
Basis $0.800	[redacted]												
usage	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	
fuel	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	
Total Delivered	[redacted]												
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	6.95%	8.21%	8.21%	8.21%	8.21%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO ETX													
Basis	[redacted]												
Usage to M3	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	$0.0960	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	6.95%	8.21%	8.21%	8.21%	8.21%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO STX													
Basis	[redacted]												
Usage to M3	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	$0.1021	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	7.95%	9.59%	9.59%	9.59%	9.59%	7.95%	7.95%	7.95%	7.95%	7.95%	7.95%	7.95%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5
08-Aug-2012

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	$0.0979	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel to M3	7.25%	8.64%	8.64%	8.64%	8.64%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO -> NF -> TRANSCO													
Basis	[redacted]												
Usage to M2	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	
Usage on NF	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	$0.0166	
Usage on Transco	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	
Usage on AGT	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	
Fuel to M2	6.19%	7.19%	7.19%	7.19%	7.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	
Fuel on NF	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	
Fuel on Transco	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Delivered to NF	[redacted]												
Delivered to Transco													
Delivered to Algonquin													
Total Delivered													
M3 DELIVERED													
Basis	[redacted]												
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
COLUMBIA MAUMEE													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
COLUMBIA BROADRUN													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
COLUMBIA EAGLE													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

REDACTED VERSION

National Grid
2012 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 08-Aug-2012

Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
COLUMBIA DOWNINGTOWN													
Basis	[redacted]												
Usage on Columbia	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	$0.0254	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Columbia	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	1.963%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TETCO -> DTI -> TETCO													
Basis	[redacted]												
Usage to M2	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	$0.4378	
Usage on Dominion	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	$0.0252	
Usage on Tetco	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
Usage on AGT	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	
Fuel to M2	6.19%	7.19%	7.19%	7.19%	7.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	
Fuel on Dominion	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Delivered to Dominion	[redacted]												
Delivered to Tetco													
Delivered to Algonquin													
Total Delivered													
TRANSCO ZONE 2													
Basis	[redacted]												
Usage on Transco	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	$0.05035	
Usage on Tetco	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Transco	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
TRANSCO ZONE 3													
Basis	[redacted]												
Usage on Transco	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	$0.04634	
Usage on Tetco	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
Usage on AGT	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
Fuel on Transco	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	3.62%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
DAWN TO TENNESSEE - ANE II													
Basis	[redacted]												
Transcanada usage	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
Transcanada pressure chg	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	$0.0352	
Iroquois usage	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	
Tenn usage	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	
Fuel on Union	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	1.305%	
Fuel on TCPL	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	1.360%	
Fuel on Iroquois	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
Fuel on Tenn	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	[redacted]												

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Natural Gas Supply VS. Requirements Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
NIAGARA TO TENNESSEE													
Basis	[redacted]												
Tenn usage	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	$0.0829	
Tenn Fuel	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	[redacted]												
Tetco to B&W - SCT													
Basis	[redacted]												
usage on Tetco	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	$0.5482	
usage on AGT	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	$0.2291	
fuel to ZN 3	7.20%	8.56%	8.56%	8.56%	8.56%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	
Fuel on AGT	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												
Hubline													
Basis $0.8680	[redacted]												
usage	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	$0.0130	
fuel	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	
Total Delivered	[redacted]												

Total Delivered to the City Gate Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
TENN CONNEXION												
Delivered Mmbtu	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600
NYMEX $/Mmbtu Del	$3.353	$3.606	$3.739	$3.730	$3.712	$3.671	$3.699	$3.741	$3.791	$3.813	$3.813	$3.832
Total Delivered Cost	$1,166,789	$1,296,706	$1,344,652	$1,211,480	$1,334,913	$1,277,351	$1,330,044	$1,302,001	$1,363,381	$1,371,248	$1,327,014	$1,377,990
Tennessee Zn 0												
Delivered Mmbtu	56,252	183,396	162,135	180,085	122,567	107,993	60,699	39,341	0	0	0	0
NYMEX $/Mmbtu Del	$3.665	$3.918	$4.052	$4.042	$4.025	$3.983	$4.011	$4.054	$4.104	$4.126	$4.126	$4.144
Total Delivered Cost	$206,178	$718,614	$656,924	$727,964	$493,286	$430,130	$243,469	$159,480	$0	$0	$0	$0
TENN ZONE 1												
Delivered Mmbtu	117,048	381,604	337,365	374,715	255,033	224,707	126,301	81,859	0	0	0	0
$/Mmbtu Del	$3.749	$3.879	$4.016	$4.059	$4.060	$4.049	$4.043	$4.030	$4.088	$4.095	$4.211	$4.211
Total Delivered Cost	$438,820	$1,480,095	$1,355,011	$1,520,947	$1,035,429	$909,746	$510,685	$329,886	$0	$0	$0	$0
TENN DRACUT												
Delivered Mmbtu	0	35,000	0	0	0	0	19,200	0	0	0	0	0
$/Mmbtu Del	$4.14	$5.80	$7.53	$6.64	$4.73	$4.04	$3.82	$3.88	$3.99	$4.03	$3.93	$4.06
Total Delivered Cost	$0	$202,906	$0	$0	$0	$0	$73,308	$0	$0	$0	$0	$0
TETCO ELA												
Delivered Mmbtu	0	230,267	326,736	260,657	0	164,378	168,230	105,658	29,856	6,177	5,986	6,177
$/Mmbtu Del	$3.6343	$3.9527	$4.0815	$4.0892	$4.0595	$3.9598	$3.9836	$4.0401	$4.0693	$4.0965	$4.0976	$4.1279
Total Delivered Cost	$0	$910,185	$1,333,569	$1,065,875	$0	$650,903	$670,168	$426,865	$121,494	$25,304	$24,530	$25,498

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TETCO ETX													
Delivered Mmbtu	0	68,982	97,881	78,086	0	49,243	50,397	31,652	8,944	1,850	1,793	1,850	
NYMEX $/Mmbtu Del	$3.5020	$3.8405	$3.9626	$3.9857	$3.9362	$3.8730	$3.8817	$3.9598	$4.0401	$4.0010	$4.0249	$4.0824	
Total Delivered Cost	$0	$264,924	$387,869	$311,230	$0	$190,720	$195,625	$125,337	$36,134	$7,404	$7,218	$7,554	
TETCO STX													
Delivered Mmbtu	0	102,816	145,890	116,385	0	73,396	75,116	47,177	13,331	2,758	2,673	2,758	
NYMEX $/Mmbtu Del	$3.622	$3.948	$4.069	$4.085	$4.057	$3.953	$3.980	$4.023	$4.083	$4.106	$4.106	$4.132	
Total Delivered Cost	$0	$405,946	$593,618	$475,384	$0	$290,130	$298,987	$189,799	$54,435	$11,326	$10,976	$11,396	
TETCO WLA													
Delivered Mmbtu	0	158,251	224,549	179,136	0	112,969	115,615	72,613	20,518	4,245	4,114	4,245	
$/Mmbtu Del	$3.6760	$4.0015	$4.0866	$4.0988	$4.0689	$3.9774	$4.0014	$4.0242	$4.0906	$4.1145	$4.1156	$4.1461	
Total Delivered Cost	$0	$633,238	$917,645	$734,239	$0	$449,324	$462,619	$292,212	$83,932	$17,467	$16,932	$17,601	
TETCO -> NF -> TRANSCO													
Delivered Mmbtu	0	11,283	16,011	12,773	0	8,055	8,243	5,177	1,463	303	293	303	
Delivered $/Mmbtu	$4.2501	$4.5594	$4.6885	$4.6963	$4.6665	$4.5775	$4.6015	$4.6582	$4.6877	$4.7150	$4.7161	$4.7466	
Delivered Cost	$0	$51,446	$75,066	$59,983	$0	$36,871	$37,932	$24,118	$6,858	$1,427	$1,383	$1,437	
M3 DELIVERED													
Delivered Mmbtu	595,600	304,600	203,700	125,100	1,119,700	531,500	518,400	27,000	0	0	29,800	518,400	
Delivered $/Mmbtu	$3.5509	$4.2473	$4.8090	$4.4968	$3.8908	$3.7901	$3.7952	$3.8315	$3.9052	$3.9264	$3.8406	$3.8759	
Delivered Cost	$2,114,918	$1,293,741	$979,585	$562,554	$4,356,504	$2,014,453	$1,967,418	$103,451	$0	$0	$114,450	$2,009,280	
COLUMBIA MAUMEE													
Delivered Mmbtu	762,400	1,173,100	1,172,900	1,059,400	1,172,900	774,600	82,400	102,800	1,700	0	0	41,900	
Delivered $/Mmbtu	$3.4415	$3.6912	$3.8076	$3.8158	$3.7777	$3.7853	$3.7977	$3.8245	$3.8584	$3.8698	$3.8646	$3.8832	
Total Delivered Cost	$2,623,770	$4,330,104	$4,465,923	$4,042,493	$4,430,877	$2,932,130	$312,931	$393,156	$6,559	$0	$0	$162,704	
COLUMBIA BROADRUN													
Delivered Mmbtu	291,400	300,900	300,800	271,700	300,800	291,600	301,400	291,400	251,300	252,500	291,600	301,100	
Delivered $/Mmbtu	$3.3972	$3.6675	$3.7921	$3.7777	$3.7190	$3.7153	$3.7668	$3.7833	$3.8131	$3.8183	$3.7926	$3.7884	
Total Delivered Cost	$989,941	$1,103,540	$1,140,674	$1,026,404	$1,118,670	$1,083,391	$1,135,318	$1,102,450	$958,244	$964,119	$1,105,909	$1,140,698	
COLUMBIA EAGLE													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.6474	$4.3578	$4.9306	$4.6123	$3.9941	$3.8914	$3.8965	$3.9336	$4.0088	$4.0304	$3.9429	$3.9789	
Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
COLUMBIA DOWNINGTOWN													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.6711	$4.4165	$5.1676	$4.8008	$4.0250	$3.8986	$3.8924	$3.9295	$4.0222	$4.0407	$3.9429	$3.9758	
Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

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TETCO -> DTI -> TETCO													
Delivered Mmbtu	0	6,697	9,502	7,581	0	4,781	4,893	3,073	868	180	174	180	
Delivered $/Mmbtu	$4.3630	$4.6810	$4.8138	$4.8217	$4.7911	$4.6996	$4.7243	$4.7826	$4.8129	$4.8410	$4.8421	$4.8735	
Delivered Cost	$0	$31,348	$45,743	$36,552	$0	$22,467	$23,114	$14,696	$4,179	$870	$843	$876	
TRANSCO ZONE 2													
Delivered Mmbtu	3,915	4,013	4,013	3,621	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.5477	$3.7953	$3.9370	$3.9168	$3.9306	$3.8842	$3.8906	$3.9577	$4.0109	$4.0163	$4.0269	$4.0567	
Delivered Cost	$13,889	$15,230	$15,798	$14,184	$0	$0	$0	$0	$0	$0	$0	$0	
TRANSCO ZONE 3													
Delivered Mmbtu	85	87	87	79	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.5550	$3.8155	$3.9376	$3.9493	$3.9163	$3.8796	$3.9030	$3.9528	$3.9921	$4.0250	$4.0197	$4.0303	
Delivered Cost	$303	$333	$343	$311	$0	$0	$0	$0	$0	$0	$0	$0	
DAWN TO TENNESSEE - ANE II													
Delivered Mmbtu	30,000	31,000	31,000	28,000	31,000	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.9729	$4.2095	$4.2282	$4.2344	$4.2168	$4.0840	$4.1068	$4.1556	$4.1566	$4.1587	$4.2158	$4.2448	
Total Delivered Cost	$119,188	$130,495	$131,074	$118,564	$130,721	$0	$0	$0	$0	$0	$0	$0	
NIAGARA TO TENNESSEE													
Delivered Mmbtu	0	3,200	0	0	0	32,000	0	0	0	0	0	0	
Delivered $/Mmbtu	$3.7755	$4.0894	$4.1075	$4.1136	$4.0964	$3.9168	$3.9390	$4.0036	$3.9925	$4.0086	$4.0450	$4.0732	
Total Delivered Cost	$0	$13,086	$0	$0	$0	$125,337	$0	$0	$0	$0	$0	$0	
Tetco to B&W - SCT													
Delivered Mmbtu	0	25,604	36,331	28,983	0	18,278	18,706	11,748	3,320	687	666	687	
Delivered $/Mmbtu	$4.3164	$4.6403	$4.7696	$4.7773	$4.7475	$4.6427	$4.6666	$4.7232	$4.7526	$4.7798	$4.7808	$4.8113	
Total Delivered Cost	$0	$118,811	$173,282	$138,462	$0	$84,858	$87,294	$55,490	$15,777	$3,283	$3,182	$3,305	
HUBLINE													
Total Delivered Vol	0	109,000	92,100	83,100	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.2171	$5.9524	$7.7635	$6.7494	$4.7675	$4.0980	$3.8699	$3.9728	$4.1212	$4.1424	$4.0294	$4.1515	
Total Delivered Cost	$0	$648,811	$715,019	$560,872	$0	$0	$0	$0	$0	$0	$0	$0	
	NOV	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	
Total Pipeline Costs	$7,673,795	$13,649,557	$14,331,795	$12,607,498	$12,900,400	$10,497,811	$7,348,912	$4,518,941	$2,650,994	$2,402,448	$2,612,438	$4,758,338	$95,952,928
Total Pipeline Volumes	2,204,700	3,489,400	3,520,600	3,134,200	3,361,600	2,741,500	1,909,200	1,167,500	690,900	628,300	685,100	1,237,200	24,770,200
WACOG	$3.4807	$3.9117	$4.0708	$4.0226	$3.8376	$3.8292	$3.8492	$3.8706	$3.8370	$3.8237	$3.8132	$3.8461	$3.8737
Injections	0	0	0	0	0	642,900	668,900	437,100	99,900	39,400	42,200	16,200	1,946,600
Value at WACOG	$0	$0	$0	$0	$0	$2,461,807	$2,574,737	$1,691,845	$383,318	$150,655	$160,918	$62,306	$7,485,585
Pipeline Costs less Injections	$7,673,795	$13,649,557	$14,331,795	$12,607,498	$12,900,400	$8,036,005	$4,774,175	$2,827,096	$2,267,677	$2,251,793	$2,451,520	$4,696,032	$88,467,342
Pipeline Volumes less injections	2,204,700	3,489,400	3,520,600	3,134,200	3,361,600	2,098,600	1,240,300	730,400	591,000	588,900	642,900	1,221,000	22,823,600
NYMEX cost of Supplies	$7,268,896	$12,352,476	$12,860,752	$11,483,709	$12,226,139	$7,569,650	$4,501,049	$2,676,916	$2,191,428	$2,196,008	$2,400,589	$4,593,402	$82,321,013
Non-gas cost of delivered supplies													**$0.2693**

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

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

Effective Period: November 1, 2012 through October 31, 2013

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	91%
January 1	86%
January 15	77%
February 1	67%
February 15	57%
March 1	48%
March 15	47%
April 1	46%

Peaking Inventory:

Inventory Level allocated on November 1, 2012 = MSQ-P
Injections are not allowed.
Minimum Inventory Levels:

November 1	100%
January 1	81%
February 1	48%
March 1	19%
April 1	5%

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

FT-2 Storage Variable Costs

SLF - Weighted Average Loss Factor on Storage Withdrawals

Storage	Withdrawals	Fuel %	Fuel Vol.	Fuel Avg.
TENN 501	360,300	0.00%	0	
GSS 300170	0	0.00%	0	
GSS 300168	42,700	0.00%	0	
GSS 300171	112,000	0.00%	0	
GSS-TE 600045	424,600	0.00%	0	
TETCO 400515	28,400	0.77%	219	
TETCO 400221	594,000	3.28%	19,483	
TETCO 400185	13,000	3.28%	426	
GSS 300169	103,900	0.00%	0	
COL FSS 9630	142,700	0.00%	0	
TENN 62918	125,000	0.00%	0	
	1,946,600		20,128	**1.0340%**

WWCC - Weighted Average Commodity Cost of Storage Withdrawals

Storage	Withdrawals	Unit Cost	Cost	Average
TENN 501	360,300	$0.0087	$3,135	
GSS 300170	0	$0.0193	$0	
GSS 300168	42,700	$0.0193	$824	
GSS 300171	112,000	$0.0193	$2,162	
GSS-TE 600045	424,600	$0.0244	$10,360	
TETCO 400515	28,181	$0.0346	$975	
TETCO 400221	574,517	$0.0606	$34,816	
TETCO 400185	12,574	$0.0606	$762	
GSS 300169	103,900	$0.0193	$2,005	
COL FSS 9630	142,700	$0.0153	$2,183	
TENN 62918	125,000	$0.0087	$1,088	
	1,926,472		$58,309	**$0.0303**

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

Storage	Transported		Fuel %		Fuel Vol.	Fuel Avg.
TENN 501	360,300			1.20%	4,324	
GSS 300170	0		2.85%	1.20%	0	
GSS 300168	42,700			1.20%	512	
GSS 300171	112,000		1.29%	1.00%	2,550	
GSS-TE 600045	424,600		1.50%	1.00%	10,551	
TETCO 400515	28,181		3.98%	1.00%	1,391	
TETCO 400221	574,517			1.00%	5,745	
TETCO 400185	12,574			1.00%	126	
GSS 300169	103,900	2.85%	0.00%	1.00%	3,971	
COL FSS 9630	142,700		1.963%	1.00%	4,200	
TENN 62918	125,000			1.20%	1,500	
	1,926,472				34,870	**1.8101%**

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

Storage	Withdrawals		Unit Cost		Cost	Average
TENN 501	356,000			$0.1091	$38,840	
GSS 300170	0		$0.0252	$0.1091	$0	
GSS 300168	42,200			$0.1091	$4,604	
GSS 300171	109,400		$0.0018	$0.0130	$1,619	
GSS-TE 600045	413,800		$0.0018	$0.0130	$6,124	
TETCO 400515	26,800		$0.0518	$0.0130	$1,737	
TETCO 400221	568,600			$0.0130	$7,392	
TETCO 400185	12,400			$0.0130	$161	
GSS 300169	99,800	$0.0252	$0.0018	$0.0130	$3,992	
COL FSS 9630	138,600		$0.0252	$0.0130	$5,295	
TENN 62918	123,500			$0.1091	$13,474	
	1,891,100				$83,237	**$0.0440**

DIRECT TESTIMONY

OF

ANN E. LEARY

September 4, 2012

Table of Contents

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. What is your position and responsibilities?

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

Q. Please describe your educational and professional background.

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

Q. Have you previously testified or appeared before this Commission?

A. I have not testified previously before this Commission. However, I have testified extensively in several ratemaking and regulatory proceedings before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission. In addition, I am currently a witness in the Company's Base Rate filing Docket No. 4323.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to explain the Gas Cost Recovery ("GCR") charges to be effective on November 1, 2012 for the following services: (1) Firm sales service 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) Gas Marketer Fixed Charges and factors associated with transportation services billed to Gas Marketers.

Q. How is your testimony organized?

A. My testimony is composed of four (4) general sections: I. Introduction; II. GCR Rate Development Overview; III. GCR Rate Development Details; and IV. Bill Impacts.

Q. Are you including any Attachments with your testimony?

A. Yes. I am sponsoring the following Attachments:

Attachment AEL-1 Gas Cost Recovery Factors

Attachment AEL-2 Annual GCR Reconciliation Filing including Attachment 1 only.

Attachment AEL-3 Projected Gas Cost Balances

Attachment AEL-4 Bill Impact Analysis

Attachment AEL-5 FT-2 Demand Rate

Attachment AEL-6 FT-2 Capacity Allocator Percentages

Attachment AEL-7 Marketer Reconciliation

II. GCR RATE DEVELOPMENT OVERVIEW

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

A. The proposed GCR rates reflect the load specific (high load and low load) factors necessary for the Company to collect the projected gas costs allocated to firm customers for the period November 1, 2012 through October 31, 2013. As shown in the testimony of Ms. Arangio on Attachment EDA-1, firm customers' gas costs for the period are projected to be approximately $159.6 million for the twelve months ended October 2013. In addition to these projected costs, the GCR factors also reflect Working Capital Costs of approximately $1.1 million (Attachment AEL-1, page 2 line 9 and page 3 line 6), Inventory Financing Costs of approximately $1.9 million (Attachment AEL-1, page 3 lines 9-10), a prior period Deferred Balance of approximately $0.1 million including the Marketer Fixed Cost Reconciliation (Attachment AEL-1 page 2 line 10-11 and page 3 line 7) based on actual data through July 2012 and forecast data for the period August 2012 through October 2012, LNG Operation and Maintenance ("O&M") Costs of approximately $1.0 million (Docket No. 3943) (Attachment AEL-1 page 2 line 8 and page 3 line 8, a $1.2 million credit associated with FT-2 Marketer Storage Demand costs (Attachment AEL-1 page 2 line 4), and a credit of approximately $1.0 million associated with LNG Costs (Attachment AEL-1 page 2 line 5 and page 3 line 3) which will be collected via the Distribution Adjustment Clause ("DAC") factor[1]. Thus, the GCR factors are intended to recover approximately $161.5 million in costs over the period November 2012 through October 2013.

Q. Please describe the changes to the GCR Rate Development that are part of this filing.

A. In this filing, the Company has simplified gas costs for high load factor rate classes and low load factor rate classes by consolidating all fixed gas costs into a single Fixed Gas Cost component and all variable gas costs into a single Variable

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[1] This figure aggregates LNG commodity related gas costs of: 1. Withdrawal commodity, $372,608; 2. Inventory Finance, $82,079; and Demand charges, $622,659.

Gas Cost component. This filing implements the approach presented in last year's GCR filing Docket No. 4283, which was not fully implemented due to issues related to the Company's billing system modifications. Further, this approach is now in line with the way the Commission approves a single rate applicable to the high load factor rate classes and a single rate applicable to the low load factor rate classes[2] in accordance with the restructuring of gas costs rates approved in Docket No. 3943 at 90.

In addition to the changes to the GCR, this filing also includes the redesign of the FT-2 rate as approved in Docket No. 4270, which will be implemented on November 1, 2012. These changes include the modification of the FT-2 storage charges for marketers, which will improve the alignment between how storage fixed costs are incurred and how they are recovered.

III. GCR RATE DEVELOPMENT DETAILS

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

A. The proposed GCR rates were developed utilizing Fixed and Variable cost components. The Company has consolidated the previous five bucket system into

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[2] Under this rate design, the Residential–Non-Heating, the Large High Load Commercial and Industrial ("C&I') and the Extra-Large High Load C&I rate classes comprised the high load factor group, and the Residential-Heating, Small C&I, Medium C&I, Large Low Load C&I and Extra-Large Low Load C&I rate classes comprise the low load factor group.

fixed and variable components by combining the supply fixed and storage fixed costs into the fixed cost component and the supply variable, storage variable product and storage variable non-product costs into the variable costs component. Attachment AEL-1 provides a summary of the GCR fixed and variable gas cost components used to derive the rates the Company seeks approval for in this filing for effect November 1, 2012.

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

A. The fixed cost component includes all of the fixed costs related to the purchase, storage, and delivery of firm gas for both the high load factor and low load factor customers. As shown on Attachment AEL-1, page 2, the fixed cost component is derived by taking the total fixed costs (net of Capacity Release), less any credits such as Natural Gas Portfolio Management Plan ("NGPMP") customer credits, LNG Demand costs allocated to the DAC, and storage demand costs billed to FT-2 Marketers. The FT-2 storage demand costs are calculated by multiplying the FT-2 Demand Charge rate by the forecast of storage and peaking Maximum Daily Quantity ("MDQ") to be billed to FT-2 Marketers. Adjustments are also made for Supply related LNG costs, working capital costs and prior period Deferred Fixed Gas Costs under/over-collection balances including an adjustment for the Marketer Fixed Cost Reconciliation as stipulated in the settlement agreement between the Company and the Division in Docket No. 4199. This results in total Fixed Gas Costs of $44,849,323 that are to be collected over the period November 2012 through October 2013. Finally, because the Company's gas-supply resources are planned so that there is sufficient capacity to meet the needs of firm sales customers under design winter conditions, the total Fixed Gas Costs are allocated to the various rate classes based on their proportion of design-winter use. The factor rates are derived using the allocated supply fixed costs and dividing them by the projected throughput for the upcoming year for each class. In this case the High Load classes would be expected to use 2.9% of the total throughput or 952,267 Dths while the Low Load classes would use the remaining 97.1% or 23,927,611 Dths. Accordingly, the GCR Fixed Low Load Factor of $1.8206 per dekatherm while the GCR Fixed High Load Factor is $1.3509 per dekatherm.

Q. Please describe how the Company calculated the Marketer Fixed Cost Reconciliation Balance?

A. In the Settlement Agreement approved in Docket No. 4199, the Company agreed to provide a reconciliation of Marketer fixed costs.[3] In the Company's 2011-2012 GCR Filing, Docket No. 4283, the Company included an adjustment

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[3] Order No. 20230 in Docket No. 4199 at 25.

associated with the Marketer fixed cost reconciliation. The reconciliation calculation has been updated and revised to better reflect the difference between projected and actual fixed costs paid by marketers during the two GCR years, 2010- 2011 and 2011 – 2012, (including last year's reconciliation credit) and the system actual weighted average cost of capacity in each year. Attachment AEL-7, shows the calculation of the Marketer reconciliation adjustment for both the 2010-2011 and 2011-2012 periods. The Company calculated the Marketer Reconciliation by updating the pipeline surcharge/credit for each path based on actual instead of projected pipeline capacity costs. The Company then compared the approved projected pipeline surcharge/credit (including the 2011- 2012 adjustment for the prior period reconciliation) for each path with the updated actual pipeline surcharge/credit and multiplied this variance by the Marketer's actual monthly capacity. (Please note- in the calculation of the 2010-2011 updated actual pipeline surcharge/credit, the Company used the final approved November 2011 Tennessee rates for the months of June 2011 through October 2011 and not the actual Tennessee rates billed during that period. Since the Company had directly provided each Marketer their portion of the Tennessee refund associated with the true up between the actual rates billed during June 2011-October 2011 and the rates finally approved in November 2011, the Company used the November 2011 approved rates in the recalculation of the 2010-2011 reconciliation to avoid a double credit to those Marketers purchasing

Tennessee capacity.) The Marketer fixed cost reconciliation for the two year period of 2010-2012 resulted in a net surcharge to Marketers of $374,462. In addition to crediting firm sales customers fixed costs for this amount, the Company included this reconciliation in its calculation of the 2012-2013 pipeline surcharge/credits detailed in Ms. Arangio's testimony. See Attachment EDA-4.

Q. How did the Company develop its design winter calculations?

A. The Company developed its design winter calculation using calendar month degree days consistent with Commission's finding in Docket No. 4097.

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

A. The variable cost component includes all variable costs of gas such as commodity costs; supply related LNG O&M, working capital, inventory finance costs; pipeline refunds, credit for the balancing related LNG costs to the DAC, and deferred cost balances. As shown on Attachment AEL-1, page 3 line 12 the total Variable Costs for the period November 2012 through October 2013 is $116,682,698. The variable costs are divided by the projected period throughput of 24,879,878 Dths to obtain a variable cost factor of $4.6898 per Dth.

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 2012, and forecasted data for the period August 2012 through October 2012, the total estimated deferred balance at October 31, 2012 is an under collection of approximately $487,002 as shown in Attachment AEL-1, page 7. This balance is incorporated into the development of the GCR rates for the period November 1, 2012 to October 31, 2013. In addition, the projected deferred gas cost balances for the November 2012 through October 2013 period are shown on Attachment AEL-3.

Q. Does the estimated October 31, 2012 deferred gas cost balance include any corrections identified by Ernst & Young (E&Y) as part of its analysis of gas costs?

A. Yes. As described in the Company's August 1, 2012 Annual GCR filing, Docket No. 4346, the Company commissioned the accounting firm of Ernst & Young ("E&Y") to perform an analysis and validation of gas costs in the Company's Gas Cost Recovery filings, which extended from September 2006[4] through June 2012. The broad time period covered by this review was undertaken in order to ensure that E&Y confirmed the calculation of the Company's GCR deferred balance filings since the time the Company acquired its gas operations in 2006

[4]Due to the absence of detailed account information from the acquisition of Narragansett Electric Company in August 2006, E&Y relied on a gas cost reconciliation filed with the RIPUC for information prior to that time.

until the present. In the course of that analysis, E&Y calculated revised monthly deferral balances resulting in proposed deferred balance adjustments of approximately $5.5 million in over collections. The Company has included a copy of the E&Y report in its 2012 Annual Gas Cost Reconciliation Filing in Docket 4346 submitted on August 1, 2012.

This analysis identified adjustments in the following areas:

- Capacity Release - $11,700,017;
- Conoco Hedges – ($6,669,322);
- Non-firm Gas Costs – ($10,353,515);
- Company Use - $2,136,371;
- Gas Cost Errors – ($2,053,984);
- Gas Collections Errors – ($193,165)
- Working Capital and Inventory Finance - $416,821;
- Interest – ($466,827).

Q. In addition to validating the historical gas costs, did E&Y recommend any process improvements?

A. Yes. In addition to validating gas costs, E&Y developed re-designed spreadsheets used in the process for calculating the monthly GCR deferral to reduce the chance of error and improve data quality. E&Y also recommend process improvement opportunities which the Company is currently implementing. This includes the establishments of various spreadsheet checks and balances and the validation of gas costs with the Company’s general ledger.

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

A. Yes. Consistent with the modifications in Docket No. 4270, the Company is submitting for approval its FT-2 marketer demand rate of $7.3770 per MDQ in Dth/month as shown in Attachment AEL-5. In addition, the Company is also submitting for approval the capacity assignment percentages for the high load and low load factors to be used in the determination of pipeline, underground storage and peaking capacity for Marketers. These percentages are set forth in Attachment AEL-6.

Q. Please describe how the proposed FT-2 marketer demand rate is calculated.

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

The FT-2 storage demand rate is derived by adding the total fixed storage costs, associated inventory finance, working capital charges and supply related LNG O&M costs less any LNG demand credits assigned to the DAC and refunds if applicable. That total is then divided by the total storage and peaking MDQ for the year to derive a monthly per dekatherm rate to be charged to Marketers. As shown in Attachment AEL-5, the proposed FT-2 marketer demand rate is $7.3770 per Dth and will be applied to the marketer's storage and peaking MDQ.

In addition, under the new rate design Marketers will now be charged a variable storage rate at the time gas is withdrawn from storage. Specifically, Marketers will be charged the gas storage inventory rate at the time it is withdrawn from storage, including all associated variable costs for transporting that storage gas to the city gate. These associated cost factors are provided in Ms. Arangio's testimony, Attachment EDA-5. In order to ensure that firm customers are appropriately compensated for these variable costs, the Company will calculate the variable storage rate each month and credit firm customers in the monthly deferred filings for the variable storage costs incurred by the Marketers.[5]

IV. BILL IMPACTS

Q. What is the combined bill impact of the proposed DAC and GCR rates on customer bills as compared to the rates currently in effect?

[5] The Company will calculate the FT-2 variable storage rate each month and will file the rate with the Commission and Division, similar to the process that is currently followed for the Transitional Sales Service surcharge.

A. An average residential heating customer using 922 therms per year will experience a total bill decrease related to the proposed GCR and DAC rates of approximately $72 or an annual 5.6% percent decrease over the current existing rates. This decrease is comprised of a $112 decrease in GCR related costs offset by a $40 increase in the DAC related costs filed today under separate cover, Docket No. 4339. A summary of annual bill impacts for customers with various levels of usage is provided on Attachment AEL-4.

Q. Does this conclude your testimony?

A. Yes.

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2012

Line No.	Description (a)	Source Reference (b)	Line #	High Load[1] (c)	Low Load[2] (d)	FT-2 Mkter[3] (e)
1	Fixed Cost Factor	**AEL-1 pg 2**	Line 17	$1.3509	$1.8206	
2	Variable Cost Factor	**AEL-1 pg 3**	Line 14	$4.6898	$4.6898	
3	Total Gas Cost Recovery Charge	(1)+(2)		$6.0407	$6.5104	
4	Uncollectible %	Docket 3943		2.46%	2.46%	
5	Total GCR Charge adjusted for Uncollectibles	(3) / [(1 - (4)]		$6.1930	$6.6746	
6	**GCR Charge on a per therm basis**	(5) / 10		**$0.6193**	**$0.6675**	
	Current rate effective 11/01/11			$0.7464	$0.7896	
	difference			($0.1271)	($0.1221)	
				-17.0%	-15.5%	

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load
[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load
[3] See AEL-5 for calculation of FT-2 rate

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

Line No.	Description (a)	Reference	Source Line # (b)	Amount (c)	High Load Factor Total (e)	Low Load Factor Total (d)	Line No.
1	Fixed Costs (net of Cap Rel to marketers)	**AEL-1 pg 4**	Line 56	$40,043,545			1
	Less:						
2	NGPMP Customer Benefit	EDA-1		($4,600,000)			2
3	Interruptible Costs			$0			3
4	FT-2 Storage Demand Costs	**AEL-5 pg 3**	Line 5	($1,178,704)			4
5	LNG Demand to DAC	**AEL-1 pg 4**	Line (33 + 52) x (18.12%)*	($622,659)			5
6	Refunds			$0			6
7	Total Credits	sum[(3):(7)]		($6,401,363)			7
	Plus:						
8	Supply Related LNG O&M Costs	Rate Case		$618,591			8
9	Working Capital Requirement	**AEL-1 pg 8**	Line 15	$265,525			9
10	Deferred Fixed Cost Balance	**AEL-1 pg 6**	Line 12 + Line 25	$10,697,488			10
11	Reconciliation Amount from Fixed costs- Marketers	EDA-4		($374,462)			11
12	Total Additions	sum[(8):(11)]		$11,207,142			12
13	Total Fixed Costs	(1) + (7) + (12)		$44,849,323			13
14	Design Winter Sales Percentage	**AEL-1 pg 12**	Lines 10 & 11		2.87%	97.13%	14
15	Allocated Supply Fixed Costs	(13) x (14)			$1,286,428	$43,562,895	15
16	Sales (Dt) Nov 2012 - Oct 2013	**AEL-1 pg 11**	Line 12	24,879,878	952,267	23,927,611	16
17	**Fixed Factor**	(15) / (16)			**$1.3509**	**$1.8206**	17

* System Balancing Factor (Dkt 4283)

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

Line No.	Description	Source Reference	Source Line #	Amount	Line No.
1	**Variable Costs**	**AEL-1 pg 4-5**	Line 87 - 81	$124,155,464	1
	Less:				
2	Non-Firm Sales			$0	2
3	Balancing Related LNG Costs (to DAC)	**AEL-1 pg 4-5**	Line 84 x (18.12%)*	($372,608)	3
4	Refunds	**AEL-1 pg 4-5**	Line 81	$0	4
5	Total Credits	sum [(2):(4)]		($372,608)	5
	Plus:				
6	Working Capital	**AEL-1 pg 8-9**	Line 31	$823,727	6
7	Reconciliation Amount	**AEL-1 pg 6-7**	Line 40 & 57 & 70	($10,210,487)	7
8	Supply Related LNG O&M	Docket 3943		$430,129	8
9	Inventory Financing - LNG (Supply)	**AEL-1 pg 10**	Line 25	$370,897	9
10	Inventory Financing - Storage	**AEL-1 pg 10**	Line 12	$1,485,575	10
11	Total Additions	sum [(6):(10)]		($7,100,158)	11
12	Total Variable Supply Costs	(1)+(5)+(11)		$116,682,698	12
13	Sales (Dt) Nov 2012 - Oct 2013	**AEL-1 pg 11**	Line 12	24,879,878	13
14	**Variable Cost Factor**	(12)/(13)		**$4.6898**	14

* System Balancing Factor (Dkt 4283)

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

Line No.		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-Oct
	SUPPLY FIXED COSTS - Pipeline Delivery													
1	Algonquin	650,451	650,451	650,451	650,451	650,451	650,451	650,451	650,451	650,451	650,451	650,451	650,451	7,805,408
2	Texas Eastern	212,532	212,532	212,532	212,532	212,532	212,532	212,532	212,532	212,532	212,532	212,532	212,532	2,550,389
3	TETCO	525,034	525,034	525,034	525,034	525,034	525,034	525,034	525,034	525,034	525,034	525,034	525,034	6,300,411
4	Tennessee	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	1,015,024	12,180,286
5	NETNE	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Iroquois	6,676	6,676	6,676	6,676	6,676	6,676	6,676	6,676	6,676	6,676	6,676	6,676	80,115
7	Union	2,429	2,510	2,510	2,267	2,510	2,429	2,510	2,429	2,510	2,510	2,429	2,510	29,556
8	Transcanada	10,459	10,808	10,808	9,762	10,808	10,459	10,808	10,459	10,808	10,808	10,459	10,808	127,251
9	Dominion	2,311	2,311	2,311	2,311	2,311	2,311	2,311	2,311	2,311	2,311	2,311	2,311	27,735
10	Transco	6,404	6,618	6,618	5,977	6,618	6,404	6,618	6,404	6,618	6,618	6,404	6,618	77,916
11	National Fuel	4,663	4,663	4,663	4,663	4,663	4,663	4,663	4,663	4,663	4,663	4,663	4,663	55,955
12	Columbia	288,384	288,384	288,384	288,384	288,384	288,384	288,384	288,384	288,384	288,384	288,384	288,384	3,460,608
13	Hubline	74,203	74,203	74,203	74,203	74,203	74,203	74,203	74,203	74,203	74,203	74,203	74,203	890,437
14	Westerly Lateral	56,324	56,324	54,984	54,984	54,984	54,984	54,984	54,984	54,984	54,984	54,984	54,984	662,490
15	East to West	84,341	84,341	84,341	84,341	84,341	84,341	84,341	84,341	84,341	84,341	84,341	84,341	1,012,092
16	Less Credits from Mkter Releases	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(551,270)	(6,615,235)
17	**TOTAL SUPPLY FIXED COSTS - Pipeline**	2,387,966	2,388,609	2,387,270	2,385,341	2,387,270	2,386,627	2,387,270	2,386,627	2,387,270	2,387,270	2,386,627	2,387,270	28,645,415
	Supply Fixed - Supplier													
18	Distrigas FCS													
19	**Total**	2,387,966	2,388,609	2,387,270	2,385,341	2,387,270	2,386,627	2,387,270	2,386,627	2,387,270	2,387,270	2,386,627	2,387,270	28,645,415
20	**Total Supply Fixed (Pipeline & Supplier)**	2,387,966	2,388,609	2,387,270	2,385,341	2,387,270	2,386,627	2,387,270	2,386,627	2,387,270	2,387,270	2,386,627	2,387,270	28,645,415
	STORAGE FIXED COSTS - Facilities													
21	Texas Eastern SS-1 Demand	81,515	81,515	81,515	81,515	81,515	81,515	81,515	81,515	81,515	81,515	81,515	81,515	978,175
22	Texas Eastern SS-1 Capacity	13,361	13,361	13,361	13,361	13,361	13,361	13,361	13,361	13,361	13,361	13,361	13,361	160,336
23	Texas Eastern FSS-1 Demand	845	845	845	845	845	845	845	845	845	845	845	845	10,139
24	Texas Eastern FSS-1 Capacity	610	610	610	610	610	610	610	610	610	610	610	610	7,324
25	Dominion GSS Demand	21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	257,087
26	Dominion GSS Capiacity	15,070	15,070	15,070	15,070	15,070	15,070	15,070	15,070	15,070	15,070	15,070	15,070	180,839
27	Dominion GSS-TE Demand	26,936	26,936	26,936	26,936	26,936	26,936	26,936	26,936	26,936	26,936	26,936	26,936	323,236
28	Dominion GSS-TE Capacity	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	239,480
29	Tennessee FSMA Demand	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	32,600	391,203
30	Tennessee FSMA Capacity	17,204	17,204	17,204	17,204	17,204	17,204	17,204	17,204	17,204	17,204	17,204	17,204	206,445
31	Columbia FSS Demand	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	46,085
32	Columbia FSS Capacity	5,894	5,894	5,894	5,894	5,894	5,894	5,894	5,894	5,894	5,894	5,894	5,894	70,732
33	Keyspan LNG Tank Lease Payment	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
34	**TOTAL FIXED STORAGE COSTS**	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	4,835,962
	STORAGE FIXED COSTS - Delivery													
35	Algonquin for TETCO SS-1	84,498	84,498	84,498	84,498	84,498	84,498	84,498	84,498	84,498	84,498	84,498	84,498	1,013,979
36	Algonquin delivery for FSS	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	67,709
37	TETCO delivery for FSS	4,964	4,964	4,964	4,964	4,964	4,964	4,964	4,964	4,964	4,964	4,964	4,964	59,563
38	Algonquin SCT for SS-1	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	19,079
39	Algonquin delivery for GSS, GSS-TE,	70,165	70,165	70,165	70,165	70,165	70,165	70,165	70,165	70,165	70,165	70,165	70,165	841,982
40	Algonquin SCT delivery for GSS-TE	447	447	447	447	447	447	447	447	447	447	447	447	5,365
41	Algonquin delivery for GSS Conv	20,168	20,168	20,168	20,168	20,168	20,168	20,168	20,168	20,168	20,168	20,168	20,168	242,013
42	Tennessee delivery for GSS	57,093	57,093	57,093	57,093	57,093	57,093	57,093	57,093	57,093	57,093	57,093	57,093	685,111
43	Tennessee delivery for FSMA	34,901	34,901	34,901	34,901	34,901	34,901	34,901	34,901	34,901	34,901	34,901	34,901	418,809
44	TETCO delivery for GSS	34,123	34,123	34,123	34,123	34,123	34,123	34,123	34,123	34,123	34,123	34,123	34,123	409,480
45	TETCO delivery for GSS-TE	3,538	3,538	3,538	3,538	3,538	3,538	3,538	3,538	3,538	3,538	3,538	3,538	42,455
46	TETCO delivery for GSS-TE	34,396	34,396	34,396	34,396	34,396	34,396	34,396	34,396	34,396	34,396	34,396	34,396	412,746
47	TETCO delivery for GSS Conv	10,674	10,674	10,674	10,674	10,674	10,674	10,674	10,674	10,674	10,674	10,674	10,674	128,087
48	Dominion delivery for GSS Conv	8,871	8,871	8,871	8,871	8,871	8,871	8,871	8,871	8,871	8,871	8,871	8,871	106,447
49	Dominion delivery for GSS	22,914	22,914	22,914	22,914	22,914	22,914	22,914	22,914	22,914	22,914	22,914	22,914	274,974
50	Algonquin delivery for FSS	15,212	15,212	15,212	15,212	15,212	15,212	15,212	15,212	15,212	15,212	15,212	15,212	182,541
51	Columbia Delivery for FSS	15,033	15,033	15,033	15,033	15,033	15,033	15,033	15,033	15,033	15,033	15,033	15,033	180,400
52	Distrigas FLS call payment	118,750	118,750	118,750	118,750	118,750	125,383	125,383	125,383	125,383	125,383	125,383	125,383	1,471,430
53	Less Credits from Mkter Releases													
54	**STORAGE DELIVERY FIXED COST**	542,978	542,978	542,978	542,978	542,978	549,611	549,611	549,611	549,611	549,611	549,611	549,611	6,562,168
55	**TOTAL STORAGE FIXED**	945,975	945,975	945,975	945,975	945,975	952,608	952,608	952,608	952,608	952,608	952,608	952,608	11,398,130
56	**TOTAL FIXED COSTS**	3,333,941	3,334,584	3,333,245	3,331,316	3,333,245	3,339,235	3,339,878	3,339,235	3,339,878	3,339,878	3,339,235	3,339,878	40,043,545

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

Line No.		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-Oct
	VARIABLE SUPPLY COSTS (Includes Injections)													
57	Tennessee Zone 0	206,178	718,614	656,924	727,964	493,286	430,130	243,469	159,480	0	0	0	0	3,636,045
58	Tennessee Zone 1	438,820	1,480,095	1,355,011	1,520,947	1,035,429	909,746	510,685	329,886	0	0	0	0	7,580,619
59	Tennessee Connexion	1,166,789	1,296,706	1,344,652	1,211,480	1,334,913	1,277,351	1,330,044	1,302,001	1,363,381	1,371,248	1,327,014	1,377,990	15,703,569
60	Tennessee Dracut	0	202,906	0	0	0	0	73,308	0	0	0	0	0	276,214
61	TETCO STX	0	405,946	593,618	475,384	0	290,130	298,987	189,799	54,435	11,326	10,976	11,396	2,341,997
62	TETCO ELA	0	910,185	1,333,569	1,065,875	0	650,903	670,168	426,865	121,494	25,304	24,530	25,498	5,254,390
63	TETCO WLA	0	633,238	917,645	734,239	0	449,324	462,619	292,212	83,932	17,467	16,932	17,601	3,625,210
64	TETCO ETX	0	264,924	387,869	311,230	0	190,720	195,625	125,337	36,134	7,404	7,218	7,554	1,534,016
65	TETCO NF	0	51,446	75,066	59,983	0	36,871	37,932	24,118	6,858	1,427	1,383	1,437	296,521
66	M3 Delivered	2,114,918	1,293,741	979,585	562,554	4,356,504	2,014,453	1,967,418	103,451	0	0	114,450	2,009,280	15,516,353
67	Maumee	2,623,770	4,330,104	4,465,923	4,042,493	4,430,877	2,932,130	312,931	393,156	6,559	0	0	162,704	23,700,646
68	Broadrun Col	989,941	1,103,540	1,140,674	1,026,404	1,118,670	1,083,391	1,135,318	1,102,450	958,244	964,119	1,105,909	1,140,698	12,869,358
69	Columbia Eagle and Downingtown	0	0	0	0	0	0	0	0	0	0	0	0	0
70	Transco Zone 2	13,889	15,230	15,798	14,184	0	0	0	0	0	0	0	0	59,100
71	Dominion to TETCO FTS	0	31,348	45,743	36,552	0	22,467	23,114	14,696	4,179	870	843	876	180,687
72	Transco Zone 3	303	333	343	311	0	0	0	0	0	0	0	0	1,290
73	ANE to Tennessee	119,188	130,495	131,074	118,564	130,721	0	0	0	0	0	0	0	630,043
74	Niagara to Tennessee	0	13,086	0	0	0	125,337	0	0	0	0	0	0	138,423
75	TETCO to B & W	0	118,811	173,282	138,462	0	84,858	87,294	55,490	15,777	3,283	3,182	3,305	683,745
76	DistriGas FCS													0
77	Hubline	0	648,811	715,019	560,872	0	0	0	0	0	0	0	0	1,924,702
78	Total Pipeline Commodity Charges	7,673,795	13,649,557	14,331,795	12,607,498	12,900,400	10,497,811	7,348,912	4,518,941	2,650,994	2,402,448	2,612,438	4,758,338	95,952,928
79	Hedging 2,937,811		3,308,328	3,521,856	2,677,745	2,967,584	1,488,598	889,801	612,975	621,754	538,642	382,288	344,471	20,291,853
80	Costs of Injections	0	0	0	0	0	(2,810,893)	(2,886,484)	(1,921,337)	(473,220)	(184,433)	(184,466)	(66,817)	(8,527,648)
81	Refunds													0
82	**TOTAL VARIABLE SUPPLY COSTS**	10,611,606	16,957,885	17,853,651	15,285,243	15,867,984	9,175,517	5,352,229	3,210,580	2,799,528	2,756,658	2,810,260	5,035,992	107,717,133
83	Underground Storage	0	1,611,095	6,922,920	5,134,424	245,598	0	0	0	0	0	0	112,685	14,026,722
84	LNG Withdrawals and Trucking	105,291	510,215	350,598	201,062	109,212	105,291	109,212	108,710	115,127	115,127	110,994	115,499	2,056,336
85	Storage Delivery Costs	0	34,268	174,468	136,135	5,721	0	0	0	0	0	0	4,682	355,274
86	**TOTAL VARIABLE STORAGE COSTS**	105,291	2,155,578	7,447,986	5,471,620	360,531	105,291	109,212	108,710	115,127	115,127	110,994	232,866	16,438,331
87	**TOTAL VARIABLE COSTS**	10,716,897	19,113,463	25,301,637	20,756,863	16,228,514	9,280,808	5,461,441	3,319,290	2,914,655	2,871,784	2,921,254	5,268,858	124,155,464
88	**TOTAL SUPPLY COSTS**	14,050,838	22,448,047	28,634,881	24,088,179	19,561,759	12,620,043	8,801,319	6,658,524	6,254,533	6,211,662	6,260,488	8,608,736	164,199,009
	Storage Costs for FT-2 Calculation													
89	**Storage Fixed Costs - Facilities**	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	402,997	4,835,962
90	**Storage Fixed Costs - Deliveries**	542,978	542,978	542,978	542,978	542,978	549,611	549,611	549,611	549,611	549,611	549,611	549,611	6,562,168
91	**Total Storage Costs**	945,975	945,975	945,975	945,975	945,975	952,608	952,608	952,608	952,608	952,608	952,608	952,608	11,398,130

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

Line No.		Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
		31	30	31	30	31	31	30	31
		actual	actual	actual	actual	actual	forecast	forecast	forecast
	I. Supply Fixed Cost Deferred								
1	Beginning Balance	$4,542,227	$3,622,411	$2,761,030	$3,566,306	$5,135,693	$6,444,991	$8,234,772	$9,923,967
2	Supply Fixed Costs (net of cap rel)	$2,420,835	$2,175,399	$2,301,228	$2,602,517	$2,200,867	$2,637,174	$2,636,499	$2,637,174
3	Capacity Release	$0	$0	$0	$0	$0	$0	$0	$0
4	NGPMP Credits	($326,667)	($1,040,994)	($326,667)	($326,667)	($326,667)	($326,667)	($326,667)	($326,667)
5	Working Capital	$16,066	$14,437	$15,272	$17,272	$14,606	$17,502	$17,497	$17,502
6	Total Supply Fixed Costs	$2,110,234	$1,148,842	$1,989,834	$2,293,122	$1,888,807	$2,328,009	$2,327,330	$2,328,009
7	Supply Fixed - Collections	$3,034,381	$2,013,501	$1,187,915	$728,203	$585,654	$546,016	$647,458	$685,387
8	Prelim. Ending Balance	$3,618,080	$2,757,753	$3,562,949	$5,131,226	$6,438,847	$8,226,983	$9,914,643	$11,566,588
9	Month's Average Balance	$4,080,153	$3,190,082	$3,161,990	$4,348,766	$5,787,270	$7,335,987	$9,074,707	$10,745,278
10	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
11	Interest Applied	$4,332	$3,277	$3,357	$4,468	$6,144	$7,788	$9,323	$11,408
12	Supply Fixed Ending Balance	$3,622,411	$2,761,030	$3,566,306	$5,135,693	$6,444,991	$8,234,772	$9,923,967	$11,577,996
	II. Storage Fixed Cost Deferred								
13	Beginning Balance	($3,200,098)	($3,655,954)	($3,706,601)	($3,434,575)	($3,319,121)	($2,842,091)	($2,153,388)	($1,500,464)
14	Storage Fixed Costs	$770,389	$782,521	$774,727	$436,007	$727,807	$876,522	$876,522	$876,522
15	LNG Demand to DAC	($56,567)	($52,389)	($52,389)	($52,389)	($52,389)	($29,670)	($29,670)	($29,670)
16	Supply Related LNG O & M	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549
17	Working Capital	$5,079	$5,188	$5,136	$2,888	$4,825	$5,962	$5,962	$5,962
18	Total Storage Fixed Costs	$770,452	$786,869	$779,023	$438,055	$731,792	$904,364	$904,364	$904,364
19	TSS Peaking Collections	$0	$0	$0	$0	$0	$0	$0	$0
20	Storage Fixed - Collections	$1,222,670	$833,736	$503,208	$319,134	$251,493	$213,011	$249,564	$283,145
21	Prelim. Ending Balance	($3,652,317)	($3,702,821)	($3,430,786)	($3,315,653)	($2,838,822)	($2,150,738)	($1,498,588)	($879,244)
22	Month's Average Balance	($3,426,207)	($3,679,387)	($3,568,694)	($3,375,114)	($3,078,972)	($2,496,414)	($1,825,988)	($1,189,854)
23	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
24	Interest Applied	($3,637)	($3,780)	($3,789)	($3,468)	($3,269)	($2,650)	($1,876)	($1,263)
25	Storage Fixed Ending Balance	($3,655,954)	($3,706,601)	($3,434,575)	($3,319,121)	($2,842,091)	($2,153,388)	($1,500,464)	($880,508)
	III. Variable Supply Cost Deferred								
26	Beginning Balance	($4,095,967)	($8,665,808)	($11,580,864)	($12,852,837)	($13,902,852)	($14,253,608)	($14,081,944)	($15,148,266)
27	Variable Supply Costs	$13,015,136	$8,797,510	$5,753,837	$3,222,939	$3,117,585	$3,417,404	$2,810,168	$5,297,426
28	Variable Delivery Storage	($10,262)	($1,764)	($1,716)	($2,756)	($2,196)	$0	$0	$0
29	Variable Injections Storage	($6,736)	($6,359)	($9,612)	($5,558)	($4,822)	($611)	($10,518)	($392)
30	Fuel Cost Allocated to Storage	($11,789)	($10,078)	($14,899)	($9,989)	($9,500)	($2,412)	($26,551)	($1,780)
31	Working Capital	$86,185	$58,265	$38,012	$21,268	$20,581	$22,660	$18,404	$35,142
32	Total Supply Variable Costs	$13,072,534	$8,837,574	$5,765,621	$3,225,903	$3,121,648	$3,437,041	$2,791,502	$5,330,397
33	Supply Variable - Collections	$17,643,818	$11,743,654	$7,026,260	$4,262,652	$3,457,510	$3,250,344	$3,842,816	$4,065,455
34	Deferred Responsibility	($8,213)	($1,420)	($1,629)	($471)	($45)	$0	$0	$0
35	Prelim. Ending Balance	($8,659,037)	($11,570,468)	($12,839,874)	($13,889,115)	($14,238,670)	($14,066,911)	($15,133,258)	($13,883,324)
36	Month's Average Balance	($6,377,502)	($10,118,138)	($12,210,369)	($13,370,976)	($14,070,761)	($14,160,259)	($14,607,601)	($14,515,795)
37	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
38	Interest Applied	($6,771)	($10,395)	($12,963)	($13,737)	($14,938)	($15,033)	($15,008)	($15,411)
39	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0
40	Supply Variable Ending Balance	($8,665,808)	($11,580,864)	($12,852,837)	($13,902,852)	($14,253,608)	($14,081,944)	($15,148,266)	($13,898,735)

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

Line No.		Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
		31	30	31	30	31	31	30	31
		actual	actual	actual	actual	actual	forecast	forecast	forecast
	IVa. Storage Variable Product Cost Deferred								
41	Beginning Balance	$10,920,603	$7,189,013	$5,581,359	$6,314,234	$4,703,516	$4,795,321	$4,521,429	$4,150,576
42	Storage Variable Prod. Costs - LNG	$415,824	$81,388	$73,019	$96,291	$117,174	$116,130	$111,839	$116,274
43	Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0	$0	$0	$0
44	Storage Variable Prod. Costs - UG	($1,036,118)	$317,500	$1,751,151	($1,117,579)	$390,861	$0	$0	$0
45	Supply Related LNG to DAC	$6,799	($14,747)	($13,231)	($17,448)	($21,232)	($21,043)	($20,265)	($21,069)
46	Supply Related LNG O & M	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844
47	Inventory Financing - LNG	$22,706	$22,626	$22,303	$25,323	$26,583	$39,188	$39,316	$39,450
48	Inventory Financing - UG	$120,472	$137,160	$147,763	$174,044	$181,249	$160,017	$178,115	$178,769
49	Inventory Financing - LP	$0	$0	$0	$0	$0	$0	$0	$0
50	Working Capital	($3,834)	$2,787	$12,256	($6,656)	$3,469	$869	$846	$870
51	Total Storage Variable Product Costs	($438,308)	$582,557	$2,029,106	($810,181)	$733,948	$331,005	$345,695	$350,138
52	Storage Variable Product Collections	$3,302,890	$2,196,768	$1,302,541	$806,194	$647,183	$609,840	$721,001	$762,773
53	Prelim. Ending Balance	$7,179,405	$5,574,802	$6,307,923	$4,697,860	$4,790,282	$4,516,487	$4,146,123	$3,737,941
54	Month's Average Balance	$9,050,004	$6,381,907	$5,944,641	$5,506,047	$4,746,899	$4,655,904	$4,333,776	$3,944,258
55	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
56	Interest Applied	$9,608	$6,557	$6,311	$5,657	$5,040	$4,943	$4,453	$4,187
57	Storage Variable Product Ending Bal.	$7,189,013	$5,581,359	$6,314,234	$4,703,516	$4,795,321	$4,521,429	$4,150,576	$3,742,128
	IVb. Stor Var Non-Prod Cost Deferred								
58	Beginning Balance	$65,387	$29,222	($21,676)	($32,647)	($29,422)	($25,209)	($42,562)	($29,073)
59	Storage Variable Non-prod. Costs	$50,623	$8,386	$7,661	$12,060	$9,495	$0	$0	$0
60	Variable Delivery Storage Costs	$10,262	$1,764	$1,716	$2,756	$2,196	$0	$0	$0
61	Variable Injection Storage Costs	$6,736	$6,359	$9,612	$5,558	$4,822	$611	$10,518	$392
62	Fuel Costs Allocated to Storage	$11,789	$10,078	$14,899	$9,989	$9,500	$2,412	$26,551	$1,780
63	Working Capital	$527	$176	$225	$202	$173	$20	$246	$14
64	Total Storage Var Non-product Costs	$79,937	$26,763	$34,113	$30,565	$26,185	$3,043	$37,316	$2,186
65	Storage Var Non-Product Collections	$116,153	$77,664	$45,055	$27,309	$21,943	$20,360	$23,790	$26,949
66	Prelim. Ending Balance	$29,171	($21,679)	($32,618)	($29,390)	($25,180)	($42,526)	($29,036)	($53,836)
67	Month's Average Balance	$47,279	$3,771	($27,147)	($31,019)	($27,301)	($33,868)	($35,799)	($41,455)
68	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
69	Interest Applied	$50	$4	($29)	($32)	($29)	($36)	($37)	($44)
70	Storage Var Non-Product Ending Bal.	$29,222	($21,676)	($32,647)	($29,422)	($25,209)	($42,562)	($29,073)	($53,880)
	GCR Deferred Summary								
71	Beginning Balance	$8,232,152	($1,481,116)	($6,966,752)	($6,439,518)	($7,412,185)	($5,880,597)	($3,521,694)	($2,603,261)
72	Gas Costs	$15,817,492	$12,342,746	$10,853,462	$5,469,158	$6,785,393	$7,283,116	$6,689,918	$9,182,270
73	NGPMP Credits	($326,667)	($1,040,994)	($326,667)	($326,667)	($326,667)	($326,667)	($326,667)	($326,667)
74	Working Capital	$104,024	$80,853	$70,901	$34,973	$43,653	$47,013	$42,955	$59,491
75	Total Costs	$15,594,849	$11,382,605	$10,597,696	$5,177,465	$6,502,379	$7,003,462	$6,406,207	$8,915,094
76	Collections	$25,311,699	$16,863,904	$10,063,350	$6,143,020	$4,963,738	$4,639,571	$5,484,629	$5,823,709
77	Prelim. Ending Balance	($1,484,698)	($6,962,414)	($6,432,405)	($7,405,073)	($5,873,544)	($3,516,705)	($2,600,116)	$488,125
78	Month's Average Balance	$3,373,727	($4,221,765)	($6,699,578)	($6,922,296)	($6,642,865)	($4,698,651)	($3,060,905)	($1,057,568)
79	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
80	Interest Applied	$3,582	($4,337)	($7,113)	($7,112)	($7,052)	($4,988)	($3,145)	($1,123)
81	Gas Purchase Plan Incentives/(Penalties)								
82	**Ending Bal. W/ Interest**	($1,481,116)	($6,966,752)	($6,439,518)	($7,412,185)	($5,880,597)	($3,521,694)	($2,603,261)	$\boxed{\textbf{\$487,002}}$

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

Line No.	Description (a)	Source (b)	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total
	Fixed Costs		$3,333,941	$3,334,584	$3,333,245	$3,331,316	$3,333,245	$3,339,235	$3,339,878	$3,339,235	$3,339,878	$3,339,878	$3,339,235	$3,339,878	$40,043,545
1	Capacity Release Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Less: LNG Demand to DAC		($51,187)	($51,187)	($51,187)	($51,187)	($51,187)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($622,659)
3	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Plus: Supply Related LNG O&M Costs		$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$618,591
5	Allowable Working Capital Costs	sum[(1):(4)]	$3,334,303	$3,334,946	$3,333,607	$3,331,678	$3,333,607	$3,338,395	$3,339,038	$3,338,395	$3,339,038	$3,339,038	$3,338,395	$3,339,038	$40,039,476
6	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
7	Working Capital Requirement	[(5) * (6)] / 365	$222,896	$222,939	$222,849	$222,720	$222,849	$223,169	$223,212	$223,169	$223,212	$223,212	$223,169	$223,212	
8	Cost of Capital	Dkt 4339	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	
9	Return on Working Capital Requirement	(7) * (8)	$16,099	$16,102	$16,096	$16,086	$16,096	$16,119	$16,122	$16,119	$16,122	$16,122	$16,119	$16,122	
10	Weighted Cost of Debt	Dkt 4339	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	
11	Interest Expense	(7) * (10)	$4,933	$4,934	$4,932	$4,929	$4,932	$4,939	$4,940	$4,939	$4,940	$4,940	$4,939	$4,940	
12	Taxable Income	(9) - (11)	$11,166	$11,168	$11,164	$11,157	$11,164	$11,180	$11,182	$11,180	$11,182	$11,182	$11,180	$11,182	
13	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
14	Return and Tax Requirement	(12) / (13)	$17,179	$17,182	$17,175	$17,165	$17,175	$17,200	$17,203	$17,200	$17,203	$17,203	$17,200	$17,203	
15	**Fixed Working Capital Requirement**	(11) + (14)	$22,112	$22,116	$22,107	$22,094	$22,107	$22,139	$22,143	$22,139	$22,143	$22,143	$22,139	$22,143	$265,525
16	**Variable Costs**		$10,716,897	$19,113,463	$25,301,637	$20,756,863	$16,228,514	$9,280,808	$5,461,441	$3,319,290	$2,914,655	$2,871,784	$2,921,254	$5,268,858	$124,155,464
17	Less: Non-firm Sales														$0
18	Less: Supply Refunds														$0
19	Less: Balancing Related LNG Commodity (to DAC)		($19,079)	($92,451)	($63,528)	($36,432)	($19,789)	($19,079)	($19,789)	($19,698)	($20,861)	($20,861)	($20,112)	($20,928)	($372,608)
20	Plus: Supply Related LNG O&M Costs		$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$430,129
21	Allowable Working Capital Costs	sum[(16):(20)]	$10,733,662	$19,056,856	$25,273,952	$20,756,275	$16,244,569	$9,297,574	$5,477,496	$3,335,436	$2,929,638	$2,886,767	$2,936,986	$5,283,774	$124,212,985
22	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
23	Working Capital Requirement	[(21) * (22)] / 365	$717,538	$1,273,938	$1,689,546	$1,387,543	$1,085,938	$621,536	$366,167	$222,972	$195,844	$192,978	$196,335	$353,217	
24	Cost of Capital	Dkt 4339	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	
25	Return on Working Capital Requirement	(23) * (24)	$51,826	$92,013	$122,031	$100,218	$78,434	$44,892	$26,447	$16,105	$14,145	$13,938	$14,181	$25,512	
26	Weighted Cost of Debt	Dkt 4339	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	
27	Interest Expense	(23) * (26)	$15,880	$28,195	$37,393	$30,709	$24,034	$13,756	$8,104	$4,935	$4,334	$4,271	$4,345	$7,817	
28	Taxable Income	(25) - (27)	$35,945	$63,819	$84,639	$69,510	$54,401	$31,136	$18,343	$11,170	$9,811	$9,667	$9,836	$17,695	
29	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
30	Return and Tax Requirement	(28) / (29)	$55,301	$98,182	$130,213	$106,938	$83,693	$47,902	$28,220	$17,184	$15,094	$14,873	$15,132	$27,222	
31	**Variable Working Capital Requirement**	(27) + (30)	$71,181	$126,377	$167,606	$137,647	$107,727	$61,658	$36,324	$22,119	$19,428	$19,144	$19,477	$35,040	$823,727

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Storage Fixed Cost Working Capital Calculation for FT-2 Demand Rate (see AEL-5 pg 2)

Line No.	Description (a)	Source (b)	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total
	Storage Fixed Costs		$945,975	$945,975	$945,975	$945,975	$945,975	$952,608	$952,608	$952,608	$952,608	$952,608	$952,608	$952,608	$11,398,130
32	Less: LNG Demand to DAC		($51,187)	($51,187)	($51,187)	($51,187)	($51,187)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($622,659)
33	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Plus: Supply Related LNG O&M Costs		$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$618,591
35	Allowable Working Capital Costs	sum[(32):(35)]	$946,337	$946,337	$946,337	$946,337	$946,337	$951,768	$951,768	$951,768	$951,768	$951,768	$951,768	$951,768	$11,394,061
36	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
37	Working Capital Requirement	[(35) * (36)] / 365	$63,262	$63,262	$63,262	$63,262	$63,262	$63,625	$63,625	$63,625	$63,625	$63,625	$63,625	$63,625	
38	Cost of Capital	Rate Case	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	
39	Return on Working Capital Requirement	(37) * (38)	$4,569	$4,569	$4,569	$4,569	$4,569	$4,595	$4,595	$4,595	$4,595	$4,595	$4,595	$4,595	
40	Weighted Cost of Debt	Rate Case	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	
41	Interest Expense	(37) * (40)	$1,400	$1,400	$1,400	$1,400	$1,400	$1,408	$1,408	$1,408	$1,408	$1,408	$1,408	$1,408	
42	Taxable Income	(39) - (41)	$3,169	$3,169	$3,169	$3,169	$3,169	$3,187	$3,187	$3,187	$3,187	$3,187	$3,187	$3,187	
43	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
44	Return and Tax Requirement	(42) / (43)	$4,876	$4,876	$4,876	$4,876	$4,876	$4,904	$4,904	$4,904	$4,904	$4,904	$4,904	$4,904	
45	**Storage Fixed Working Capital Requirement**	(41) + (44)	$6,276	$6,276	$6,276	$6,276	$6,276	$6,312	$6,312	$6,312	$6,312	$6,312	$6,312	$6,312	$75,561

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

Line No.	Description (a)	Source (b)	Nov-12 (c)	Dec-12 (d)	Jan-13 (e)	Feb-13 (f)	Mar-13 (g)	Apr-13 (h)	May-13 (i)	Jun-13 (j)	Jul-13 (k)	Aug-13 (l)	Sep-13 (m)	Oct-13 (n)	Total (p)
1	**Storage Inventory Balance**		$17,309,838	$16,458,019	$12,786,571	$10,057,438	$9,927,277	$12,404,846	$14,995,982	$16,698,544	$17,084,311	$17,235,932	$17,397,884	$17,346,745	
2	Hedging														
3	Subtotal	(1) + (2)	$17,309,838	$16,458,019	$12,786,571	$10,057,438	$9,927,277	$12,404,846	$14,995,982	$16,698,544	$17,084,311	$17,235,932	$17,397,884	$17,346,745	
4	Cost of Capital	Dkt 4339	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	
5	Return on Working Capital Requirement	(3) * (4)	$1,250,243	$1,188,718	$923,539	$726,422	$717,020	$895,968	$1,083,119	$1,206,091	$1,233,954	$1,244,905	$1,256,602	$1,252,908	$12,979,490
6	Weighted Cost of Debt	Dkt 4339	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	
7	Interest Charges Financed	(1) * (6)	$383,098	$364,246	$282,990	$222,589	$219,708	$274,542	$331,888	$369,569	$378,106	$381,462	$385,046	$383,915	$3,977,159
8	Taxable Income	(5) - (7)	$867,145	$824,473	$640,550	$503,832	$497,312	$621,427	$751,231	$836,522	$855,847	$863,443	$871,556	$868,994	
9	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
10	Return and Tax Requirement	(8) / (9)	$1,334,069	$1,268,420	$985,461	$775,127	$765,095	$956,041	$1,155,740	$1,286,957	$1,316,688	$1,328,373	$1,340,855	$1,336,914	$13,849,740
11	Working Capital Requirement	(7) + (10)	$1,717,167	$1,632,665	$1,268,451	$997,716	$984,804	$1,230,583	$1,487,628	$1,656,526	$1,694,794	$1,709,835	$1,725,901	$1,720,828	$17,826,899
12	Monthly Average	(11) / 12	$143,097	$136,055	$105,704	$83,143	$82,067	$102,549	$123,969	$138,044	$141,233	$142,486	$143,825	$143,402	$1,485,575
13	**LNG Inventory Balance**		$4,868,042	$4,357,827	$4,007,229	$3,806,168	$3,696,956	$3,591,665	$4,492,960	$5,243,279	$5,128,152	$5,013,026	$5,286,166	$5,303,072	
14	Cost of Capital	Dkt 4339	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	
15	Return on Working Capital Requirement	(13) * (14)	$351,605	$314,754	$289,431	$274,909	$267,021	$259,416	$324,514	$378,708	$370,393	$362,077	$381,806	$383,027	$3,957,662
16	Weighted Cost of Debt	Dkt 4339	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	
17	Interest Charges Financed	(13) * (16)	$107,739	$96,447	$88,687	$84,237	$81,820	$79,490	$99,437	$116,043	$113,495	$110,947	$116,992	$117,367	$1,212,702
18	Taxable Income	(15) - (17)	$243,867	$218,308	$200,744	$190,672	$185,201	$179,926	$225,077	$262,665	$256,897	$251,130	$264,813	$265,660	
19	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
20	Return and Tax Requirement	(18) / (19)	$375,180	$335,858	$308,837	$293,341	$284,924	$276,810	$346,272	$404,100	$395,227	$386,354	$407,405	$408,708	$4,223,015
21	Working Capital Requirement	(17) + (20)	$482,918	$432,304	$397,524	$377,579	$366,745	$356,300	$445,710	$520,143	$508,722	$497,301	$524,397	$526,074	$5,435,717
22	Monthly Average	(21) / 12	$40,243	$36,025	$33,127	$31,465	$30,562	$29,692	$37,142	$43,345	$42,393	$41,442	$43,700	$43,840	$452,976
23	System Balancing Factor	Dkt 4283	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	18.12%	
24	Balancing Related Inventory Costs	(22) * (23)	$7,292	$6,528	$6,003	$5,701	$5,538	$5,380	$6,730	$7,854	$7,682	$7,509	$7,918	$7,944	$82,079
25	Supply Related Inventory Costs	(22) - (24)	$32,951	$29,498	$27,124	$25,763	$25,024	$24,312	$30,412	$35,491	$34,712	$33,933	$35,781	$35,896	$370,897

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

Line No.	Rate Class	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(p)
	SALES (dth)													
1	Residential Non-Heating	39,952	59,594	78,573	77,377	66,696	52,095	46,325	34,178	29,995	27,280	27,901	28,447	568,413
3	Residential Non-Heating Low Income													
4	Residential Heating	1,099,863	2,058,633	3,053,892	3,108,191	2,680,218	1,998,463	1,232,855	674,166	443,392	388,331	399,794	515,751	17,653,549
5	Residential Heating Low Income													
6	Small C&I	121,739	254,777	460,531	442,493	396,614	264,475	142,278	71,605	53,665	47,990	48,259	48,988	2,353,415
7	Medium C&I	207,209	321,417	519,131	539,951	483,907	330,411	217,747	126,281	99,812	92,066	97,084	111,258	3,146,273
8	Large LLF	48,903	79,494	120,029	125,067	113,419	85,261	41,244	22,552	14,944	12,089	12,648	20,290	695,940
9	Large HLF	18,760	21,377	27,399	24,235	24,333	20,881	19,186	13,244	13,661	14,634	16,000	14,038	227,748
10	Extra Large LLF	5,824	9,181	12,885	12,530	12,644	9,031	5,606	3,688	1,676	1,620	1,523	2,227	78,434
11	Extra Large HLF	13,476	17,573	12,539	15,845	13,744	11,686	13,141	12,780	10,719	10,388	11,956	12,260	156,107
12	**Total Sales**	1,555,727	2,822,047	4,284,978	4,345,689	3,791,575	2,772,304	1,718,381	958,496	667,864	594,397	615,165	753,258	24,879,878
	FT-2 TRANSPORTATION													
13	FT-2 Medium	92,888	159,599	219,045	234,859	204,413	151,837	105,327	68,711	55,908	50,329	59,272	57,359	1,459,546
14	FT-2 Large LLF	60,687	110,429	167,936	167,051	155,037	122,409	66,369	40,157	19,655	15,980	19,047	29,944	974,700
15	FT-2 Large HLF	18,521	23,975	27,099	26,494	27,954	22,743	19,797	15,478	13,152	14,036	14,742	14,350	238,339
16	FT-2 Extra Large LLF	3,015	5,220	8,530	7,548	6,718	5,357	3,709	1,489	1,425	1,446	1,414	1,359	47,230
17	FT-2 Extra Large HLF	10,716	10,540	16,390	13,759	13,375	12,647	16,583	13,581	9,378	13,944	10,967	10,056	151,936
18	**Total FT-2 Transportation**	185,827	309,764	438,999	449,710	407,496	314,992	211,785	139,415	99,519	95,734	105,441	113,068	2,871,750
	FT-1 TRANSPORTATION													
30	FT-1 Medium	64,555	104,616	100,799	116,392	78,431	58,267	35,837	31,717	27,590	30,317	32,063	44,379	724,960
31	FT-1 Large LLF	112,575	160,912	187,148	175,061	147,149	100,655	35,931	26,084	19,007	18,700	23,103	48,557	1,054,881
32	FT-1 Large HLF	41,150	47,549	45,469	53,143	51,539	38,283	35,595	31,525	28,811	30,886	31,785	29,909	465,644
33	FT-1 Extra Large LLF	100,336	147,424	160,905	156,041	130,124	84,853	38,595	18,532	15,411	15,140	20,782	46,507	934,650
34	FT-1 Extra Large HLF	370,606	461,895	413,052	395,881	361,317	316,597	360,402	346,610	351,098	355,559	374,067	348,864	4,455,947
35	**Total FT-1 Transportation**	689,221	922,394	907,373	896,517	768,560	598,655	506,360	454,467	441,917	450,601	481,800	518,216	7,636,083
	Total THROUGHPUT													
36	Residential Non-Heating	39,952	59,594	78,573	77,377	66,696	52,095	46,325	34,178	29,995	27,280	27,901	28,447	568,413
37	Residential Heating	1,099,863	2,058,633	3,053,892	3,108,191	2,680,218	1,998,463	1,232,855	674,166	443,392	388,331	399,794	515,751	17,653,549
38	Small C&I	121,739	254,777	460,531	442,493	396,614	264,475	142,278	71,605	53,665	47,990	48,259	48,988	2,353,415
39	Medium C&I	364,651	585,632	838,975	891,201	766,750	540,515	358,911	226,708	183,310	172,711	188,419	212,996	5,330,780
40	Large LLF	222,164	350,835	475,113	467,179	415,605	308,325	143,544	88,793	53,607	46,769	54,797	98,791	2,725,521
41	Large HLF	78,431	92,901	99,967	103,872	103,826	81,907	74,577	60,247	55,624	59,555	62,527	58,297	931,731
42	Extra Large LLF	109,175	161,825	182,320	176,119	149,486	99,241	47,910	23,709	18,513	18,206	23,719	50,092	1,060,314
43	Extra Large HLF	394,798	490,008	441,981	425,484	388,437	340,930	390,126	372,971	371,195	379,890	396,990	371,180	4,763,990
44	**Total Throughput**	2,430,775	4,054,205	5,631,350	5,691,916	4,967,631	3,685,951	2,436,526	1,552,377	1,209,300	1,140,732	1,202,406	1,384,542	$\boxed{35,387,711}$

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

Line No.	Rate Class (a)	Nov-12 (b)	Dec-12 (c)	Jan-13 (d)	Feb-13 (e)	Mar-13 (f)	Total (h)	% (i)
	SALES (dth)							
1	Residential Non-Heating	54,215	79,028	80,492	74,631	69,327	357,694	1.84%
2	Residential Heating	1,844,909	3,173,035	3,253,614	3,044,950	2,638,910	13,955,419	71.62%
3	Small C&I	255,693	445,790	457,341	428,306	369,222	1,956,353	10.04%
4	Medium C&I	325,338	538,712	551,596	515,197	453,307	2,384,150	12.23%
5	Large LLF	73,930	129,957	133,364	124,949	107,370	569,569	2.92%
6	Large HLF	20,759	26,871	27,216	25,036	24,585	124,467	0.64%
7	Extra Large LLF	8,101	14,104	14,469	13,550	11,687	61,911	0.32%
8	Extra Large HLF	13,546	16,328	16,476	15,077	15,345	76,772	0.39%
9	Total Sales	2,596,493	4,423,824	4,534,568	4,241,695	3,689,754	19,486,334	100.00%
10	Low Load Factor	2,507,972	4,301,598	4,410,384	4,126,951	3,580,496	18,927,401	97.13%
11	High Load Factor	88,521	122,227	124,183	114,744	109,258	558,933	2.87%

nationalgrid

Thomas R. Teehan
Senior Counsel

August 1, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: 2012 Annual Gas Cost Recovery Reconciliation

Dear Ms. Massaro:

In accordance with the provisions of the National Grid's[1] Gas Cost Recovery ("GCR") Clause Tariff, R.I.P.U.C. NG No. 101, Section 2, Schedule A, Item 1.2, enclosed are ten (10) copies of National Grid's annual GCR reconciliation filing. The reconciliation consists of six schedules and contains actual gas cost and collection data for the twelve months ending March 31, 2012.[2] In addition to the annual GCR reconciliation schedules, the Company is submitting as attachments to this filing a written report on the results of the recent analysis of the Company's GCR deferred balance calculations, along with supporting documentation.

As described in the July Monthly Deferred Balance Report, the Company commissioned the accounting firm of Ernst & Young ("E&Y") to perform an analysis and validation of gas costs in the Company's Gas Cost Recovery filings, which extended from September 2006[3] through June 2012. E&Y's analysis of the Company's GCR deferral calculations involved a comparison and reconciliation of the monthly deferral balances report and the Company's General Ledger for the months of September 2006 through November 2011. As part of its review, E&Y validated actual gas costs related to gas supply, underground and LNG storage activity, hedging, marketer invoices, non-firm sales, off-system sales, NGPMP credits, and GCR collections. Additionally, their analysis traced information among GCR filings, preliminary "two-day close" materials, the General Ledger, journal entries, source schedules, and source documents such as invoices. E&Y also validated the gas costs data for the months December 2011 through June 2012 for use in the recently filed July Monthly Deferred Balance Report.

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[1] The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company").
[2] In Docket 4199, the Company and the Division of Public Utilities and Carriers agreed to adjust the period of the annual gas cost reconciliation to reflect the Company's current fiscal year (April 1 through March 31). In Docket 4283, the Company filed an amended tariff incorporating that change.
[3]Because of the absence of detailed account information from the acquisition of the Company in August 2006, E&Y relied on a gas cost reconciliation filed with the Commission for information prior to that time.

The Company has also identified and included in this GCR annual reconciliation $453,344 in gas supply replacement costs incurred during the period March 2011 – September 2011, while DOT-required inspection, integrity testing, and repair work was performed on an interstate pipeline servicing National Grid. While that pipeline was out of service, the Company served customers utilizing an LNG vaporizer provided by Transgas. Although the Company had initially charged these costs to an account that is not included in the calculation of gas costs, the Company corrected this oversight in March 2012.

In order to fully inform the Commission with respect to E&Y's GCR deferred balance analysis, the Company is also submitting the following attachments:

- Attachment 1-Fiscal year 2012 (April 2011-March 2012) GCR Reconciliation
- Attachment 2-Summary 2006 - 2011 showing original and revised ending balances ending October of each year
- Attachment 3- High level explanation of adjustments by GCR Year (November through October).
- Attachment 4-Original detail monthly GCR Reconciliation Filings for the periods November 2005 – November 2011
- Attachment 5-Revised monthly detail GCR Reconciliation Filing for the periods November 2005 – November 2011
- Attachment 6-Monthly Variance (differences between original and revised deferrals shown on attachments 5 and 6)
- Attachment 7-E&Y Report

The enclosed 2012 annual GCR reconciliation (Attachment 1) consists of six schedules. Schedule 1 presents the monthly gas-cost specific ending deferred balances for the period April 1, 2011 through March 31, 2012, resulting in an end-of-period over-collection of approximately $1.5 million, as shown on the bottom of page 2. The $1.5 million over-collection is comprised of five distinct cost components: Supply Fixed, Storage Fixed, Supply Variable, Storage Variable Product, and Storage Variable Non-Product. The monthly balances for each of the components are also contained in Schedule 1.

Schedule 2 provides monthly gas costs by pipeline, and Schedule 3 summarizes Gas Cost Collections for the period April 2011 through March 2012.

Schedule 4 presents the calculation of inventory financing costs, and Schedule 5 provides the calculations of Working Capital consistent with the methodology approved in Docket 3943. Lastly, monthly firm throughput is summarized in Schedule 6.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosure

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

Attachment 1

The Narragansett Electric Company

2012 Annual Gas Cost Recovery Reconciliation

Attachment 1- Fiscal year 2012

(April 2011-March 2012) GCR Reconciliation

Attachment 1
April 11-March 12 GCR Reconciliation

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance

Schedule 1
Page 1 of 2

	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr - Mar
	30	31	30	31	31	30	31	30	31	31	29	31	366
	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	
I. Supply Fixed Cost Deferred													
Beginning Balance	($2,803,431)	($3,953,917)	($3,375,406)	($1,560,078)	$271,004	$2,178,473	$4,106,471	$5,499,135	$6,216,149	$6,340,426	$5,554,643	$4,542,227	
Supply Fixed Costs (net of cap rel)	$2,219,985	$1,950,996	$2,700,197	$2,556,345	$2,522,525	$2,589,061	$2,710,817	$2,364,181	$2,530,100	$2,631,108	$2,750,889	$2,420,835	$29,947,037
NGPMP Credits	($1,027,975)	($200,000)	($200,000)	($200,000)	($200,000)	($200,000)	($1,051,532)	($326,667)	($326,667)	($326,667)	($326,667)	($326,667)	($4,712,840)
Working Capital	$15,083	$13,255	$18,345	$17,368	$17,138	$17,590	$18,418	$15,690	$16,791	$17,462	$18,257	$16,066	$201,463
Total Supply Fixed Costs	$1,207,092	$1,764,251	$2,518,542	$2,373,713	$2,339,663	$2,406,651	$1,677,703	$2,053,205	$2,220,224	$2,321,903	$2,442,479	$2,110,234	$25,435,660
Supply Fixed - Collections	$2,354,109	$1,181,852	$700,680	$541,947	$433,493	$481,880	$516,117	$1,342,206	$2,102,609	$3,113,997	$3,459,906	$3,034,381	$19,263,177
Prelim. Ending Balance	($3,950,447)	($3,371,518)	($1,557,544)	$271,688	$2,177,174	$4,103,244	$5,268,057	$6,210,134	$6,333,764	$5,548,332	$4,537,215	$3,618,080	
Month's Average Balance	($3,376,939)	($3,662,717)	($2,466,475)	($644,195)	$1,224,089	$3,140,859	$4,687,264	$5,854,634	$6,274,956	$5,944,379	$5,045,929	$4,080,153	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($3,469)	($3,889)	($2,534)	($684)	$1,300	$3,227	$4,976	$6,015	$6,662	$6,311	$5,011	$4,332	$27,257
GPIP	$0	$0	$0	$0	$0	$0	$226,102	$0	$0	$0	$0	$0	$226,102
Marketer Reconcilation													$0
Supply Fixed Ending Balance	($3,953,917)	($3,375,406)	($1,560,078)	$271,004	$2,178,473	$4,106,471	$5,499,135	$6,216,149	$6,340,426	$5,554,643	$4,542,227	$3,622,411	
II. Storage Fixed Cost Deferred													
Beginning Balance	($4,072,243)	($4,731,862)	($4,646,601)	($4,219,973)	($3,733,241)	($3,193,304)	($2,686,086)	($2,180,509)	($2,011,899)	($2,141,494)	($2,586,165)	($3,200,098)	
Storage Fixed Costs	$613,490	$746,221	$813,848	$773,740	$763,838	$752,376	$774,910	$743,017	$684,098	$755,845	$716,734	$770,389	$8,908,505
LNG Demand to DAC	($27,508)	($47,187)	($37,348)	($37,348)	($37,348)	($37,348)	($37,348)	($29,670)	($56,567)	($56,567)	($56,567)	($56,567)	($517,370)
Supply Related LNG O & M	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$618,591
Working Capital	$4,331	$5,100	$5,626	$5,353	$5,286	$5,208	$5,361	$5,076	$4,507	$4,983	$4,723	$5,079	$60,635
Total Storage Fixed Costs	$641,862	$755,683	$833,675	$793,295	$783,325	$771,786	$794,473	$769,973	$683,588	$755,810	$716,440	$770,452	$9,070,360
TSS Peaking Collections	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$1
Storage Fixed - Collections	$1,296,960	$665,446	$402,494	$302,344	$239,713	$261,549	$286,312	$599,211	$810,979	$1,197,974	$1,327,501	$1,222,670	$8,613,153
Prelim. Ending Balance	($4,727,341)	($4,641,626)	($4,215,420)	($3,729,022)	($3,189,629)	($2,683,067)	($2,177,927)	($2,009,746)	($2,139,290)	($2,583,657)	($3,197,227)	($3,652,317)	
Month's Average Balance	($4,399,792)	($4,686,744)	($4,431,011)	($3,974,497)	($3,461,435)	($2,938,185)	($2,432,006)	($2,095,127)	($2,075,594)	($2,362,575)	($2,891,696)	($3,426,207)	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($4,520)	($4,976)	($4,552)	($4,220)	($3,675)	($3,019)	($2,582)	($2,153)	($2,204)	($2,508)	($2,872)	($3,637)	($40,917)
Storage Fixed Ending Balance	($4,731,862)	($4,646,601)	($4,219,973)	($3,733,241)	($3,193,304)	($2,686,086)	($2,180,509)	($2,011,899)	($2,141,494)	($2,586,165)	($3,200,098)	($3,655,954)	
III. Variable Supply Cost Deferred													
Beginning Balance	$1,811,641	($7,724,982)	($11,472,992)	($13,642,067)	($16,927,656)	($16,343,072)	($17,488,018)	($15,097,876)	($12,205,777)	($5,710,117)	($3,113,656)	($4,095,967)	
Variable Supply Costs	$9,695,707	$5,992,903	$3,666,592	$1,275,388	$4,236,094	$2,907,879	$6,671,063	$12,170,461	$18,768,619	$20,583,663	$19,051,547	$13,015,136	$118,035,053
Variable Delivery Storage	($5,205)	($4,709)	($1,660)	($8,277)	($1,597)	($669)	($3,733)	($6,444)	($8,970)	($16,879)	($23,794)	($10,262)	($92,200)
Variable Injections Storage	($11,178)	($11,127)	($8,847)	($6,493)	($14,872)	($15,324)	($8,731)	($1,853)	($3,279)	($5,466)	($1,177)	($6,736)	($95,082)
Fuel Cost Allocated to Storage	($34,544)	($29,628)	($28,072)	($20,805)	($47,373)	($42,601)	($23,460)	($3,956)	($8,572)	($12,446)	($2,680)	($11,789)	($265,927)
Working Capital	$65,528	$40,407	$24,649	$8,423	$28,347	$19,358	$45,080	$80,689	$124,422	$136,375	$126,254	$86,185	$785,716
Total Supply Variable Costs	$9,710,307	$5,987,847	$3,652,662	$1,248,236	$4,200,598	$2,868,643	$6,680,220	$12,238,897	$18,872,219	$20,685,246	$19,150,150	$13,072,534	$118,367,560
Supply Variable - Collections	$19,240,239	$9,702,164	$5,790,541	$4,517,203	$3,599,581	$3,996,219	$4,272,790	$9,335,509	$12,375,753	$18,091,448	$20,129,117	$17,643,818	$128,694,381
Deferred Responsibility	$3,655	$23,508	$18,301	$405	($1,218)	$0	$0	($2,730)	($8,700)	($7,344)	($235)	($8,213)	$17,429
Prelim. Ending Balance	($7,721,946)	($11,462,807)	($13,629,172)	($16,911,438)	($16,325,421)	($17,470,648)	($15,080,588)	($12,191,759)	($5,700,612)	($3,108,975)	($4,092,388)	($8,659,037)	
Month's Average Balance	($2,955,152)	($9,593,895)	($12,551,082)	($15,276,753)	($16,626,539)	($16,906,860)	($16,284,303)	($13,644,818)	($8,953,195)	($4,409,546)	($3,603,022)	($6,377,502)	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($3,036)	($10,185)	($12,895)	($16,218)	($17,651)	($17,370)	($17,288)	($14,019)	($9,505)	($4,681)	($3,578)	($6,771)	($133,199)
Supply Variable Ending Balance	($7,724,982)	($11,472,992)	($13,642,067)	($16,927,656)	($16,343,072)	($17,488,018)	($15,097,876)	($12,205,777)	($5,710,117)	($3,113,656)	($4,095,967)	($8,665,808)	

Attachment 1
April 11-March 12 GCR Reconciliation

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance

Schedule 1
Page 2 of 2

	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr - Mar
	30	31	30	31	31	30	31	30	31	31	29	31	366
	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	
IVa. Storage Variable Product Cost Deferred													
Beginning Balance	$5,860,284	$3,794,105	$3,234,763	$3,002,956	$3,739,983	$3,798,252	$3,985,449	$4,229,720	$4,316,605	$5,131,706	$8,211,378	$10,920,603	
Storage Variable Prod. Costs - LNG	$144,000	$210,514	$157,936	$159,200	$154,573	$110,854	$217,317	$132,967	$217,371	$1,534,727	$301,350	$415,824	$3,756,633
Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Variable Prod. Costs - UG	$691,207	$598,968	$327,864	$1,078,730	$238,456	$440,196	$442,554	$1,291,223	$2,648,256	$4,947,560	$6,011,166	($1,036,118)	$17,680,061
Supply Related LNG to DAC	($23,866)	($35,366)	($26,533)	($26,746)	($25,968)	($18,623)	($36,509)	($24,094)	($39,388)	($278,093)	($54,605)	$6,799	($582,992)
Supply Related LNG O & M	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$430,129
Inventory Financing - LNG	$31,612	$36,291	$35,061	$34,052	$36,138	$36,063	$35,938	$33,879	$32,384	$22,419	$21,063	$22,706	$377,606
Inventory Financing - UG	$106,822	$128,312	$151,174	$157,058	$184,386	$210,325	$219,260	$204,503	$188,042	$154,031	$106,896	$120,472	$1,931,281
Inventory Financing - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$5,756	$5,503	$3,364	$8,472	$2,737	$3,861	$4,479	$9,530	$18,994	$41,413	$41,769	($3,834)	$142,044
Total Storage Variable Product Costs	$991,375	$980,066	$684,709	$1,446,611	$626,166	$818,520	$918,882	$1,683,852	$3,101,505	$6,457,901	$6,463,483	($438,308)	$23,734,763
Storage Variable Product Collections	$3,062,511	$1,543,137	$919,719	$713,161	$571,897	$635,319	$678,970	$1,601,356	$2,291,416	$3,385,307	$3,763,754	$3,302,890	$22,469,437
Prelim. Ending Balance	$3,789,148	$3,231,034	$2,999,753	$3,736,406	$3,794,252	$3,981,453	$4,225,362	$4,312,217	$5,126,693	$8,204,299	$10,911,107	$7,179,405	
Month's Average Balance	$4,824,716	$3,512,569	$3,117,258	$3,369,681	$3,767,118	$3,889,852	$4,105,406	$4,270,968	$4,721,649	$6,668,003	$9,561,243	$9,050,004	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	$4,957	$3,729	$3,203	$3,577	$3,999	$3,996	$4,358	$4,388	$5,013	$7,079	$9,496	$9,608	$63,404
Storage Variable Product Ending Bal.	$3,794,105	$3,234,763	$3,002,956	$3,739,983	$3,798,252	$3,985,449	$4,229,720	$4,316,605	$5,131,706	$8,211,378	$10,920,603	$7,189,013	
IVb. Stor Var Non-Prod Cost Deferred													
Beginning Balance	($538,277)	($381,779)	($273,955)	($202,888)	($112,635)	($25,635)	$54,014	$124,728	$167,545	$158,243	$167,251	$65,387	
Storage Variable Non-prod. Costs	$22,158	$19,257	$6,923	$34,380	$6,577	$2,681	$14,752	$34,071	$47,195	$87,214	$2,110	$50,623	$327,942
Variable Delivery Storage Costs	$5,205	$4,709	$1,660	$8,277	$1,597	$669	$3,733	$6,444	$8,970	$16,879	$23,794	$10,262	$92,200
Variable Injection Storage Costs	$11,178	$11,127	$8,847	$6,493	$14,872	$15,324	$8,731	$1,853	$3,279	$5,466	$1,177	$6,736	$95,082
Fuel Costs Allocated to Storage	$34,544	$29,628	$28,072	$20,805	$47,373	$42,601	$23,460	$3,956	$8,572	$12,446	$2,680	$11,789	$265,927
Working Capital	$497	$440	$309	$475	$478	$416	$344	$307	$451	$810	$198	$527	$5,253
Total Storage Var Non-product Costs	$73,582	$65,160	$45,811	$70,431	$70,898	$61,691	$51,020	$46,632	$68,468	$122,815	$29,958	$79,937	$786,404
Storage Var Non-Product Collections	($83,388)	($43,012)	($25,501)	($19,989)	($16,176)	($17,943)	($19,599)	$3,965	$77,943	$113,979	$131,938	$116,153	$218,370
Prelim. Ending Balance	($381,307)	($273,607)	($202,643)	($112,468)	($25,561)	$54,000	$124,633	$167,395	$158,070	$167,078	$65,272	$29,171	
Month's Average Balance	($459,792)	($327,693)	($238,299)	($157,678)	($69,098)	$14,183	$89,324	$146,062	$162,807	$162,660	$116,261	$47,279	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($472)	($348)	($245)	($167)	($73)	$15	$95	$150	$173	$173	$115	$50	($535)
Storage Var Non-Product Ending Bal.	($381,779)	($273,955)	($202,888)	($112,635)	($25,635)	$54,014	$124,728	$167,545	$158,243	$167,251	$65,387	$29,222	
GCR Deferred Summary													
Beginning Balance	$257,974	($12,998,435)	($16,534,192)	($16,622,050)	($16,762,546)	($13,585,285)	($12,028,169)	($7,424,802)	($3,517,378)	$3,778,763	$8,233,451	$8,232,152	
Gas Costs	$13,560,999	$9,688,302	$7,883,106	$6,092,193	$8,166,664	$7,080,857	$11,100,148	$17,007,932	$25,107,504	$30,469,300	$28,937,976	$15,817,492	$180,912,475
NGPMP Credits	($1,027,975)	($200,000)	($200,000)	($200,000)	($200,000)	($200,000)	($1,051,532)	($326,667)	($326,667)	($326,667)	($326,667)	($326,667)	($4,712,840)
Working Capital	$91,194	$64,705	$52,293	$40,093	$53,987	$46,434	$73,682	$111,293	$165,165	$201,041	$191,200	$104,024	$1,195,111
Total Costs	$12,624,218	$9,553,007	$7,735,400	$5,932,285	$8,020,651	$6,927,291	$10,122,298	$16,792,558	$24,946,003	$30,343,675	$28,802,509	$15,594,849	$177,394,746
Collections	$25,874,087	$13,073,096	$7,806,234	$6,055,070	$4,827,289	$5,357,025	$5,734,592	$12,879,517	$17,650,000	$25,895,360	$28,811,981	$25,311,699	$179,275,949
Prelim. Ending Balance	($12,991,894)	($16,518,524)	($16,605,026)	($16,744,835)	($13,569,184)	($12,015,018)	($7,640,463)	($3,511,760)	$3,778,624	$8,227,078	$8,223,979	($1,484,698)	
Month's Average Balance	($6,366,960)	($14,758,479)	($16,569,609)	($16,683,442)	($15,165,865)	($12,800,152)	($9,834,316)	($5,468,281)	$130,623	$6,002,921	$8,228,715	$3,373,727	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($6,541)	($15,668)	($17,024)	($17,712)	($16,101)	($13,151)	($10,441)	($5,618)	$139	$6,373	$8,172	$3,582	($83,990)
Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$226,102	$0	$0	$0	$0	$0	$226,102
Ending Bal. W/ Interest	($12,998,435)	($16,534,192)	($16,622,050)	($16,762,546)	($13,585,285)	($12,028,169)	($7,424,802)	($3,517,378)	$3,778,763	$8,233,451	$8,232,152	($1,481,116)	

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance

Attachment 1
April 11-March 12 GCR Reconciliation

	Apr-11 actual	May-11 actual	Jun-11 actual	Jul-11 actual	Aug-11 actual	Sep-11 actual	Oct-11 actual	Nov-11 actual	Dec-11 actual	Jan-12 actual	Feb-12 actual	Mar-12 actual	Apr - Mar
SUPPLY FIXED COSTS - Pipeline Delivery													
Algonquin	639,787	706,566	1,020,716	869,521	869,990	868,393	870,290	872,052	1,037,363	991,108	949,100	725,335	10,420,219
Alberta Northeast	22	0	763	416	508	(345)	17		526	526	474	(51)	2,856
Texas Eastern	0	0	0	0	0	0	0	765,159	903,311	819,999	862,839	875,989	4,227,297
TETCO	426,307	818,046	771,130	778,846	785,520	768,809	735,016	0	0	0	0	0	5,083,675
Tennessee	785,151	641,226	1,155,688	1,188,401	1,210,419	1,296,626	1,450,301	1,028,887	891,113	1,140,018	1,085,702	941,329	12,814,860
NETNE	0	0	0	0	0	0	0						0
Iroquois	6,676	6,693	6,676	6,676	6,676	6,676	6,676	6,676	6,676	0	6,676	6,676	73,456
Union	0	0	0	0	0	0	0	2,530	(71)	(780)	2,479	2,519	6,676
Transcanada	0	0	0	0	0	0	0						0
Dominion	2,313	2,313	2,313	1,156	2,892	2,313	2,313	34,096	34,959	34,096	36,625	123,304	278,694
Transco	6,561	6,669	6,453	6,584	6,626	5,412	10,621	1,289	6,625	6,625	6,282	6,625	76,374
National Fuel	4,184	4,184	4,184	4,184	4,184	4,184	4,184	4,184	4,184	4,199	4,214	0	46,066
Columbia	291,347	302,186	301,968	294,574	312,418	305,233	305,395	315,540	265,769	321,915	302,332	319,604	3,638,279
Hubline	0	0	0	0	0	0	0						0
Westerly Lateral	57,637	57,637	57,637	57,656	57,637	57,637	57,637	57,637	57,485	57,010	55,011	44,628	675,245
BG LNG Energy								11,968	88,542	12,247	38,823	62,958	214,538
GDF Seuz													0
East to West	0	0	0	0	0	0	0						0
Less Credits from Mkter Releases	542,603	594,522	627,330	651,668	734,345	725,876	731,631	735,836	766,383	755,856	599,667	688,082	8,153,801
TOTAL SUPPLY FIXED COSTS - Pipeline	2,219,985	1,950,996	2,700,197	2,556,345	2,522,525	2,589,061	2,710,817	2,364,181	2,530,100	2,631,108	2,750,889	2,420,835	29,947,037
Supplier													
Distrigas FCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply Fixed (Pipeline & Supplier)	2,219,985	1,950,996	2,700,197	2,556,345	2,522,525	2,589,061	2,710,817	2,364,181	2,530,100	2,631,108	2,750,889	2,420,835	29,947,037
STORAGE FIXED COSTS - Facilities													
Texas Eastern SS-1 Demand	88,844	87,289	87,729	86,978	87,011	87,007	87,048	87,194	(268)	0	0	0	698,833
Texas Eastern SS-1 Capacity													0
Texas Eastern FSS-1 Demand													0
Texas Eastern FSS-1 Capacity													0
Dominion GSS Demand	83,655	83,655	83,655	83,655	83,655	83,655	83,655	83,387	86,440	83,387	84,978	(0)	923,775
Dominion GSS Capiacity													0
Dominion GSS-TE Demand													0
Dominion GSS-TE Capacity													0
Tennessee FSMA Demand	39,425	39,427	61,371	90,926	47,558	34,943	58,699	49,804	43,128	56,480	49,804	32,600	604,165
Tennessee FSMA Capacity													0
Columbia FSS Demand									24,720	0	0	0	24,720
Columbia FSS Capacity													0
Iroquois									6,676	112	0	0	6,788
Repsol								8,333	0	0	0	0	8,333
Keyspan LNG Tank Lease Payment	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	1,964,880
TOTAL FIXED STORAGE COSTS	367,330	374,111	396,495	425,299	381,963	369,345	393,143	392,459	324,436	303,719	298,522	196,340	4,223,162
STORAGE FIXED COSTS - Delivery													
Algonquin for TETCO SS-1	128,718	137,533	139,526	138,190	137,911	139,017	137,753	145,543	91,424	158,405	156,758	275,688	1,786,467
Algonquin delivery for FSS													0
TETCO delivery for FSS													0
Algonquin SCT for SS-1													0
Algonquin delivery for GSS, GSS-TE,													0
Algonquin SCT delivery for GSS-TE													0
Algonquin delivery for GSS Conv													0
Tennessee delivery for GSS	63,824	63,824	165,641	98,066	131,854	131,854	131,854	118,854	66,208	91,993	91,993	92,038	1,248,002
Tennessee delivery for FSMA													0
TETCO delivery for GSS	53,617	53,617	53,617	53,617	53,543	53,593	53,593	86,162	53,593	53,593	21,023	53,679	643,246
TETCO delivery for GSS-TE													0
TETCO delivery for GSS-TE													0
TETCO delivery for GSS Conv													0
Dominion delivery for GSS Conv													0
Dominion delivery for GSS													0
Algonquin delivery for FSS													0
Columbia Delivery for FSS													0
Distrigas FLS call payment	0	117,136	58,568	58,568	58,568	58,568	58,568		148,438	148,438	148,438	148,438	1,003,726
National Fuel												4,206	4,206
VPEM										(303)	0	0	(303)
STORAGE DELIVERY FIXED COST $	246,159	372,110	417,352	348,441	381,875	383,031	381,768	350,558	359,662	452,125	418,212	574,049	4,685,343
TOTAL STORAGE FIXED	613,490	746,221	813,848	773,740	763,838	752,376	774,910	743,017	684,098	755,845	716,734	770,389	8,908,505
TOTAL FIXED COSTS	2,833,474	2,697,217	3,514,044	3,330,085	3,286,362	3,341,436	3,485,727	3,107,198	3,214,198	3,386,953	3,467,623	3,191,224	38,855,541

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance

Attachment 1
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	Apr-11 actual	May-11 actual	Jun-11 actual	Jul-11 actual	Aug-11 actual	Sep-11 actual	Oct-11 actual	Nov-11 actual	Dec-11 actual	Jan-12 actual	Feb-12 actual	Mar-12 actual	Apr - Mar
VARIABLE SUPPLY COSTS (Includes Injections)													
Total Pipeline Commodity Charges	7,771,266	4,288,297	2,595,139	812,810	3,330,568	1,901,256	4,118,671	6,107,083	10,722,952	11,589,916	10,008,590	5,338,209	68,584,756
Hedging 2,570,313		1,561,096	952,140	889,870	895,617	1,295,791	2,554,521	6,136,997	8,090,460	9,471,036	9,242,977	9,248,290	52,909,108
Costs of Injections													0
Refunds (Tennessee)	(406,764)			(406,764)		(406,764)	0			(406,764)		(1,548,477)	(3,175,532)
TOTAL VARIABLE SUPPLY COSTS	9,934,814	5,849,393	3,547,279	1,295,916	4,226,185	2,790,283	6,673,192	12,244,080	18,813,413	20,654,189	19,251,567	13,038,022	118,318,333
VARIABLE STORAGE COSTS													
Underground Storage	713,365	618,224	334,787	1,113,110	245,033	442,878	457,306	1,325,294	2,695,451	5,034,774	6,013,275	(985,495)	18,008,003
LNG Withdrawals and Trucking	144,000	210,514	157,936	159,200	154,573	110,854	217,317	132,967	217,371	1,534,727	301,350	415,824	3,756,633
TOTAL VARIABLE STORAGE COSTS	857,365	828,738	492,723	1,272,310	399,606	553,731	674,623	1,458,261	2,912,822	6,569,501	6,314,625	(569,671)	21,764,636
TOTAL VARIABLE COSTS	10,792,180	6,678,131	4,040,002	2,568,226	4,625,791	3,344,014	7,347,815	13,702,342	21,726,235	27,223,690	25,566,192	12,468,351	140,082,969
TOTAL SUPPLY COSTS	13,625,654	9,375,348	7,554,047	5,898,311	7,912,153	6,685,451	10,833,542	16,809,540	24,940,433	30,610,643	29,033,815	15,659,575	178,938,510
Storage Costs for FT-2 Calculation													
Storage Fixed Costs - Facilities	367,330	374,111	396,495	425,299	381,963	369,345	393,143	392,459	324,436	303,719	298,522	196,340	4,223,162
Storage Fixed Costs - Deliveries	246,159	372,110	417,352	348,441	381,875	383,031	381,768	350,558	359,662	452,125	418,212	574,049	4,685,343
Variable Delivery Costs	5,205	4,709	1,660	8,277	1,597	669	3,733	6,444	8,970	16,879	23,794	10,262	92,200
Variable Injection/withdrawal Costs	11,178	11,127	8,847	6,493	14,872	15,324	8,731	1,853	3,279	5,466	1,177	6,736	95,082
Fuel Costs Allocated to Storage	34,544	29,628	28,072	20,805	47,373	42,601	23,460	3,956	8,572	12,446	2,680	11,789	265,927
Total Storage Costs	664,417	791,685	852,426	809,315	827,680	810,970	810,833	755,270	704,920	790,636	744,385	799,176	9,361,714
Pipeline Variable	$9,934,814	$5,849,393	$3,547,279	$1,295,916	$4,226,185	$2,790,283	$6,673,192	$12,244,080	$18,813,413	$20,654,189	$19,251,567	$13,038,022	118,318,333
Less Non-firm Gas Costs	$209,593	$60,580	$84,758	$82,117	$79,294	$74,451	$123,187	$232,486	$380,432	$178,276	$133,990	$109,223	1,748,387
Less Company Use	$82,199	$20,336	$17,894	$24,547	$41,058	($21,679)	$8,571	$28,957	$33,795	$43,404	$42,370	$52,075	373,527
Less Manchester St Balancing	$45,383	$20,056	$9,564	$9,178	$7,255	$8,810	$10,863	$13,030	$19,304	$43,830	$43,830	$18,401	249,504
Plus Cashout													0
Less Mkter Over-takes	$5,334	$0	$4,216	$25,392	$4,336	$5,441	$5,996	$140,012	$6,885	$28,950	$25,058	$0	251,620
Less Mkter W/drawals	$89,281	($18,889)	($55,969)	$22,875	$19,982	$12,189	$20,711	($223,162)	($148,276)	$22,939	$184,448	$64,311	(9,559)
Plus Mkter Undertakes	$46,865	$101,303	$52,358	$20,701	$34,382	$68,038	$42,632	($10,599)	$72,692	$68,739	$52,947	$52,607	602,665
Plus Mkter Injections								$0					0
Storage Service Charge													0
Plus Pipeline Srchg/Credit	$145,816	$124,290	$127,418	$122,880	$127,453	$128,770	$124,568	$128,303	$174,654	$178,133	$176,730	$168,518	1,727,533
TOTAL FIRM COMMODITY COSTS	$9,695,707	$5,992,903	$3,666,592	$1,275,388	$4,236,094	$2,907,879	$6,671,063	$12,170,461	$18,768,619	$20,583,663	$19,051,547	$13,015,136	118,035,053

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance
National Grid
GCR - Gas Cost Collections

Attachment 1
April 11-March 12 GCR Reconciliation

	Apr-11 actual	May-11 actual	Jun-11 actual	Jul-11 actual	Aug-11 actual	Sep-11 actual	Oct-11 actual	Nov-11 actual	Dec-11 actual	Jan-12 actual	Feb-12 actual	Mar-12 actual	Total Apr - Mar
I. Supply Fixed Cost Collections --													
(a) Low Load dth	2,788,263	1,386,304	803,520	607,863	496,718	543,919	588,024	1,444,870	2,167,029	3,232,330	3,586,992	3,140,582	20,786,414
Supply Fixed Cost Factor	$0.8200	$0.8172	$0.8199	$0.8304	$0.8050	$0.8193	$0.8184	$0.8919	$0.9419	$0.9402	$0.9401	$0.9404	
Low Load collections	$2,286,446	$1,132,899	$658,773	$504,752	$399,881	$445,621	$481,238	$1,288,746	$2,041,191	$3,039,105	$3,372,056	$2,953,408	$18,604,116
(b) High Load dth	106,657	77,221	66,178	58,662	53,003	57,192	55,152	82,160	96,677	118,036	138,549	127,454	1,036,942
Supply Fixed Cost Factor	$0.6344	$0.6339	$0.6332	$0.6341	$0.6342	$0.6340	$0.6324	$0.6507	$0.6353	$0.6345	$0.6341	$0.6353	
High Load collections	$67,663	$48,953	$41,907	$37,195	$33,612	$36,259	$34,879	$53,460	$61,418	$74,892	$87,850	$80,973	$659,061
sub-total Dth	2,894,921	1,463,524	869,697	666,525	549,721	601,110	643,176	1,527,031	2,263,705	3,350,366	3,725,541	3,268,037	21,823,355
TOTAL Supply Fixed Collections	**$2,354,109**	**$1,181,852**	**$700,680**	**$541,947**	**$433,493**	**$481,880**	**$516,117**	**$1,342,206**	**$2,102,609**	**$3,113,997**	**$3,459,906**	**$3,034,381**	**$19,263,177**
II. Storage Fixed Cost Collections --													
(a) Low Load dth	2,788,263	1,386,304	803,520	607,863	496,718	543,919	588,024	1,444,870	2,167,029	3,232,330	3,586,992	3,140,582	20,786,414
Storage Fixed Cost Factor	$0.3989	$0.3975	$0.3988	$0.4039	$0.3916	$0.3985	$0.3981	$0.3725	$0.3369	$0.3363	$0.3362	$0.3363	
Low Load collections	$1,112,235	$551,096	$320,457	$245,534	$194,519	$216,771	$234,096	$538,210	$730,051	$1,086,965	$1,206,050	$1,056,314	$7,492,298
(b) High Load dth	106,657	77,221	66,178	58,662	53,003	57,192	55,152	82,160	96,677	118,036	138,549	127,454	1,036,942
Storage Fixed Cost Factor	$0.3033	$0.3031	$0.3028	$0.3032	$0.3032	$0.3032	$0.3024	$0.2687	$0.2209	$0.2206	$0.2205	$0.2209	
High Load collections	$32,354	$23,407	$20,038	$17,787	$16,072	$17,338	$16,678	$22,073	$21,353	$26,039	$30,544	$28,152	$271,835
(c) FT-2 dth	272,234	174,976	99,159	85,083	73,855	80,970	102,547	174,749	254,172	337,494	544,128	489,404	2,688,771
Storage Fixed Cost Factor	$0.3841	$0.3841	$0.3841	$0.3841	$0.3841	$0.3841	$0.3841	$0.3566	$0.2344	$0.2518	$0.1671	$0.2824	
FT-2 collection	$104,565	$67,208	$38,087	$32,680	$28,368	$31,101	$39,388	$62,307	$59,575	$84,970	$90,907	$138,204	$777,360
sub-total Dth	3,167,155	1,638,500	968,857	751,608	623,577	682,081	745,723	1,701,779	2,517,877	3,687,860	4,269,669	3,757,440	$24,512,127
TOTAL Storage Fixed Collections	**$1,296,960**	**$665,446**	**$402,494**	**$302,344**	**$239,713**	**$261,549**	**$286,312**	**$599,211**	**$810,979**	**$1,197,974**	**$1,327,501**	**$1,222,670**	**$8,613,153**
III. Variable Supply Cost Collections --													
(a) Firm Sales dth	2,894,921	1,463,524	869,697	666,525	549,721	601,110	643,176	1,527,031	2,263,705	3,350,366	3,725,541	3,268,037	21,823,355
Variable Supply Cost Factor	$6.6274	$6.6055	$6.6250	$6.7031	$6.5174	$6.6212	$6.6133	$6.0905	$5.3951	$5.3854	$5.3845	$5.3867	
Variable Supply collections	$19,185,767	$9,667,314	$5,761,777	$4,467,766	$3,582,765	$3,980,102	$4,253,546	$9,300,304	$12,212,869	$18,043,126	$20,060,195	$17,603,853	$128,119,384
(b) TSS Sales dth	7,269	5,349	3,099	980	1,637	525	815	1,221	1,811	13,150	16,570	11,444	63,871
TSS Variable Supply Cost F.	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
TSS Surcharge collections	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$1
(c) NGV Sales dth	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable Supply Cost Factor	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Variable Supply collections	$0	$0	$0	($140)	$0	$0	$0	$0	$0	$0	$0	$0	($140)
(d) Default Sales dth	6,143	3,930	1,961	4,023	1,378	1,818	2,170	4,486	5,240	5,962	9,219	5,189	51,519
Variable Supply Cost Factor	$9.0910	$9.0910	$9.0910	$9.0910	$9.0910	$9.0910	$9.0910	$7.8960	$8.1056	$7.7018	$7.7018	$7.7018	
Variable Supply collections	$54,472	$34,850	$28,764	$49,577	$16,816	$16,117	$19,243	$35,205	$42,444	$48,322	$68,922	$39,965	$454,696
Peaking Gas revenue									$120,440				$120,440
TOTAL Variable Supply Collections	**$19,240,239**	**$9,702,164**	**$5,790,541**	**$4,517,203**	**$3,599,581**	**$3,996,219**	**$4,272,790**	**$9,335,509**	**$12,375,753**	**$18,091,448**	**$20,129,117**	**$17,643,818**	**$128,694,381**

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	Apr-11 actual	May-11 actual	Jun-11 actual	Jul-11 actual	Aug-11 actual	Sep-11 actual	Oct-11 actual	Nov-11 actual	Dec-11 actual	Jan-12 actual	Feb-12 actual	Mar-12 actual	Total Apr - Mar
IVa. Storage Variable Product Cost Collections --													
(a) Firm Sales dth	2,894,921	1,463,524	869,697	666,525	549,721	601,110	643,176	1,527,031	2,263,705	3,350,366	3,725,541	3,268,037	21,823,355
Variable Supply Cost Factor	$1.0579	$1.0544	$1.0575	$1.0700	$1.0403	$1.0569	$1.0557	$1.0487	$1.0122	$1.0104	$1.0103	$1.0107	
TOTAL Stor Var Product collections	**$3,062,511**	**$1,543,137**	**$919,719**	**$713,161**	**$571,897**	**$635,319**	**$678,970**	**$1,601,356**	**$2,291,416**	**$3,385,307**	**$3,763,754**	**$3,302,890**	**$22,469,437**
IVb. Storage Variable Non-product Cost Collections --													
(a) Firm Sales dth	2,894,921	1,463,524	869,697	666,525	549,721	601,110	643,176	1,527,031	2,263,705	3,350,366	3,725,541	3,268,037	21,823,355
Variable Supply Cost Factor	($0.0263)	($0.0262)	($0.0263)	($0.0266)	($0.0259)	($0.0263)	($0.0263)	$0.0023	$0.0310	$0.0309	$0.0309	$0.0309	
Stor Var Non-Product collec	($76,228)	($38,410)	($22,893)	($17,751)	($14,234)	($15,813)	($16,902)	$3,563	$70,089	$103,550	$115,124	$101,030	$191,125
(b) FT-2 dth	272,234	174,976	99,159	85,083	73,855	80,970	102,547	174,749	254,172	337,494	544,128	489,404	2,688,771
Variable Supply Cost Factor	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	$0.0023	$0.0309	$0.0309	$0.0309	$0.0309	
Stor Var Non-Product collec	($7,160)	($4,602)	($2,608)	($2,238)	($1,942)	($2,130)	($2,697)	$402	$7,854	$10,429	$16,814	$15,123	$27,245
Total Firm Sales/FT-2 dth	3,167,155	1,638,500	968,857	751,608	623,577	682,081	745,723	1,701,779	2,517,877	3,687,860	4,269,669	3,757,440	24,512,127
TOTAL Stor Var Non-Product collec	**($83,388)**	**($43,012)**	**($25,501)**	**($19,989)**	**($16,176)**	**($17,943)**	**($19,599)**	**$3,965**	**$77,943**	**$113,979**	**$131,938**	**$116,153**	**$218,370**
Deferred Responsibility	**$3,655**	**$23,508**	**$18,301**	**$405**	**($1,218)**	**$0**	**$0**	**($2,730)**	**($8,700)**	**($7,344)**	**($235)**	**($8,213)**	**$17,429**
Total Gas Cost Collections	**$25,874,087**	**$13,073,096**	**$7,806,234**	**$6,055,070**	**$4,827,289**	**$5,357,025**	**$5,734,591**	**$12,879,517**	**$17,650,000**	**$25,895,360**	**$28,811,981**	**$25,311,699**	**$179,275,948**

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No.	Description (a)	Reference (b)	Apr-11 (c)	May-11 (d)	Jun-11 (e)	Jul-11 (f)	Aug-11 (g)	Sep-11 (h)	Oct-11 (i)	Nov-11 (j)	Dec-11 (k)	Jan-12 (l)	Feb-12 (m)	Mar-12 (n)	Total (o)
1	**Storage Inventory Balance**		11,649,879	12,985,012	14,732,691	14,843,799	17,441,445	20,122,933	21,140,596	$19,971,317	$19,073,568	$16,766,654	$12,541,091	$14,561,908	
2	Hedging		962,847	2,165,095	3,116,688	3,700,318	4,329,345	4,710,582	4,747,817	$4,747,817	$3,655,825	$1,851,663	$379,848	$24	
3	Subtotal	(1) + (2)	12,612,726	15,150,108	17,849,378	18,544,117	21,770,790	24,833,515	25,888,413	24,719,134	$22,729,393	$18,618,318	$12,920,939	$14,561,933	$230,198,763
4	Cost of Capital	Rate Case	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.23%	7.23%	7.23%	7.23%	7.23%	
5	Return on Working Capital Requirement	(3) * (4)	941,646	1,131,083	1,332,607	1,384,475	1,625,373	1,854,031	1,932,788	1,787,193	1,643,335	1,346,104	934,184	1,052,828	$16,965,648
6	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
7	Interest Charges Financed	(1) * (6)	309,806	372,131	438,433	455,498	534,754	609,984	635,895	548,765	504,593	413,327	286,845	323,275	$5,433,305
8	Taxable Income	(5) - (7)	631,841	758,952	894,174	928,977	1,090,619	1,244,047	1,296,893	1,238,429	$1,138,743	$932,778	$647,339	$729,553	
9	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
10	Return and Tax Requirement	(8) / (9)	972,063	1,167,619	1,375,652	1,429,195	1,677,875	1,913,919	1,995,220	1,905,275	$1,751,912	$1,435,043	$995,906	$1,122,389	$17,742,066
11	Working Capital Requirement	(7) + (10)	1,281,868	1,539,750	1,814,085	1,884,693	2,212,629	2,523,903	2,631,115	2,454,040	$2,256,504	$1,848,369	$1,282,751	$1,445,664	$23,175,371
12	Monthly Average	(11) / 12	106,822	128,312	151,174	157,058	184,386	210,325	219,260	204,503	$188,042	$154,031	$106,896	$120,472	$1,931,281
13	**LNG Inventory Balance**		4,486,140	5,150,249	4,975,591	4,832,462	5,128,501	5,117,860	5,100,106	$5,001,334	$4,780,667	$3,309,527	$3,109,341	$3,351,880	
14	Cost of Capital	Rate Case	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.23%	7.23%	7.23%	7.23%	7.23%	
15	Return on Working Capital Requirement	(13) * (14)	334,928	384,510	371,470	360,784	382,886	382,091	380,766	361,596	$345,642	$239,279	$224,805	$242,341	$4,011,098
16	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
17	Interest Charges Financed	(13) * (16)	110,193	126,505	122,215	118,699	125,971	125,710	125,274	111,030	$106,131	$73,471	$69,027	$74,412	$1,288,638
18	Taxable Income	(15) - (17)	224,735	258,004	249,255	242,085	256,915	256,382	255,492	250,567	$239,511	$165,807	$155,778	$167,929	
19	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
20	Return and Tax Requirement	(18) / (19)	345,747	396,930	383,469	372,438	395,254	394,433	393,065	385,487	$368,479	$255,088	$239,658	$258,353	$4,188,401
21	Working Capital Requirement	(17) + (20)	455,940	523,435	505,684	491,137	521,225	520,143	518,339	496,517	$474,610	$328,560	$308,686	$332,764	$5,477,039
22	Monthly Average	(21) / 12	37,995	43,620	42,140	40,928	43,435	43,345	43,195	41,376	$39,551	$27,380	$25,724	$27,730	$456,420
23	System Balancing Factor	Rate Case	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	18.12%	18.12%	18.12%	18.12%	18.12%	
24	Balancing Related Inventory Costs	(22) * (23)	6,383	7,328	7,080	6,876	7,297	7,282	7,257	7,497	$7,167	$4,961	$4,661	$5,025	$78,814
25	Supply Related Inventory Costs	(22) - (24)	31,612	36,291	35,061	34,052	36,138	36,063	35,938	33,879	$32,384	$22,419	$21,063	$22,706	$377,606

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No.	Description (a)	Reference (b)	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Total
1	**Supply Fixed Costs**		$2,219,985	$1,950,996	$2,700,197	$2,556,345	$2,522,525	$2,589,061	$2,710,817	$2,364,181	$2,530,100	$2,631,108	$2,750,889	$2,420,835	$29,947,037
2	Capacity Release Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Allowable Working Capital Costs	(1) - (2)	$2,219,985	$1,950,996	$2,700,197	$2,556,345	$2,522,525	$2,589,061	$2,710,817	$2,364,181	$2,530,100	$2,631,108	$2,750,889	$2,420,835	$29,947,037
4	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$148,404	$130,423	$180,506	$170,890	$168,629	$173,077	$181,216	$158,044	$169,135	$175,888	$183,895	$161,831	
6	Cost of Capital	Rate Case	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.23%	7.23%	7.23%	7.23%	7.23%	
7	Return on Working Capital Requirement	(5) * (6)	$11,080	$9,737	$13,476	$12,758	$12,590	$12,922	$13,529	$11,427	$12,228	$12,717	$13,296	$11,700	
8	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
9	Interest Expense	(5) * (8)	$3,645	$3,204	$4,434	$4,198	$4,142	$4,251	$4,451	$3,509	$3,755	$3,905	$4,082	$3,593	
10	Taxable Income	(7) - (9)	$7,434	$6,534	$9,043	$8,561	$8,448	$8,670	$9,078	$7,918	$8,474	$8,812	$9,213	$8,108	
11	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
12	Return and Tax Requirement	(10) / (11)	$11,438	$10,052	$13,912	$13,170	$12,996	$13,339	$13,966	$12,182	$13,036	$13,557	$14,174	$12,473	
13	**Supply Fixed Working Capital Requirement**	(9) + (12)	$15,083	$13,255	$18,345	$17,368	$17,138	$17,590	$18,418	$15,690	$16,791	$17,462	$18,257	$16,066	$201,463
14	**Storage Fixed Costs**		$613,490	$746,221	$813,848	$773,740	$763,838	$752,376	$774,910	$743,017	$684,098	$755,845	$716,734	$770,389	$8,908,505
15	Less: LNG Demand to DAC		$27,508	$47,187	$37,348	$37,348	$37,348	$37,348	$37,348	$29,670	$56,567	$56,567	$56,567	$56,567	$517,370
16	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Plus: Supply Related LNG O&M Costs		$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$618,591
18	Allowable Working Capital Costs	(14) - (15) + (16)	$637,531	$750,583	$828,049	$787,941	$778,039	$766,577	$789,112	$764,897	$679,081	$750,827	$711,717	$765,372	$9,009,726
19	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
20	Working Capital Requirement	[(17) * (18)] / 365	$42,618	$50,176	$55,355	$52,673	$52,011	$51,245	$52,752	$51,133	$45,396	$50,192	$47,578	$51,165	
21	Cost of Capital	Rate Case	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.23%	7.23%	7.23%	7.23%	7.23%	
22	Return on Working Capital Requirement	(19) * (20)	$3,182	$3,746	$4,133	$3,933	$3,883	$3,826	$3,938	$3,697	$3,282	$3,629	$3,440	$3,699	
23	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
24	Interest Expense	(19) * (22)	$1,047	$1,232	$1,360	$1,294	$1,278	$1,259	$1,296	$1,135	$1,008	$1,114	$1,056	$1,136	
25	Taxable Income	(19) - (23)	$2,135	$2,514	$2,773	$2,639	$2,606	$2,567	$2,643	$2,562	$2,274	$2,515	$2,384	$2,563	
26	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
27	Return and Tax Requirement	(24) / (25)	$3,285	$3,867	$4,266	$4,060	$4,009	$3,949	$4,066	$3,941	$3,499	$3,869	$3,667	$3,944	
28	**Storage Fixed Working Capital Requirement**	(23) + (26)	$4,331	$5,100	$5,626	$5,353	$5,286	$5,208	$5,361	$5,076	$4,507	$4,983	$4,723	$5,079	$60,635
1	**Supply Variable Costs**		$9,695,707	$5,992,903	$3,666,592	$1,275,388	$4,236,094	$2,907,879	$6,671,063	$12,170,461	$18,768,619	$20,583,663	$19,051,547	$13,015,136	$118,035,053
2a	Less: Non-firm Sales														$0
2b	Less: Variable Delivery Storage Costs		$5,205	$4,709	$1,660	$8,277	$1,597	$669	$3,733	$6,444	$8,970	$16,879	$23,794	$10,262	$92,200
2c	Less: Variable Injection Storage Costs		$11,178	$11,127	$8,847	$6,493	$14,872	$15,324	$8,731	$1,853	$3,279	$5,466	$1,177	$6,736	$95,082
2d	Less: Fuel Costs Allocated to Storage		$34,544	$29,628	$28,072	$20,805	$47,373	$42,601	$23,460	$3,956	$8,572	$12,446	$2,680	$11,789	$265,927
2e	Less: Supply Refunds														$0
2	Total Credits		$50,927	$45,464	$38,579	$35,575	$63,843	$58,594	$35,923	$12,253	$20,821	$34,791	$27,651	$28,787	$453,209
3	Allowable Working Capital Costs	(1) - (2)	$9,644,779	$5,947,439	$3,628,013	$1,239,813	$4,172,252	$2,849,285	$6,635,140	$12,158,208	$18,747,797	$20,548,872	$19,023,896	$12,986,349	$117,581,844
4	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$644,747	$397,582	$242,530	$82,881	$278,912	$190,473	$443,555	$812,768	$1,253,277	$1,373,678	$1,271,734	$868,129	
6	Cost of Capital	Rate Case	$0	$0	$0	$0	$0	$0	$0	$0	7.23%	7.23%	7.23%	7.23%	
7	Return on Working Capital Requirement	(5) * (6)	$48,136	$29,683	$18,107	$6,188	$20,823	$14,220	$33,115	$58,763	$90,612	$99,317	$91,946	$62,766	
8	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
9	Interest Expense	(5) * (8)	$15,837	$9,766	$5,957	$2,036	$6,851	$4,679	$10,895	$18,043	$27,823	$30,496	$28,233	$19,272	
10	Taxable Income	(7) - (9)	$32,299	$19,917	$12,150	$4,152	$13,972	$9,542	$22,220	$40,720	$62,789	$68,821	$63,714	$43,493	
11	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
12	Return and Tax Requirement	(10) / (11)	$49,691	$30,642	$18,692	$6,388	$21,496	$14,680	$34,185	$62,646	$96,599	$105,879	$98,021	$66,913	
13	**Supply Variable Working Capital Requirement**	(9) + (12)	$65,528	$40,407	$24,649	$8,423	$28,347	$19,358	$45,080	$80,689	$124,422	$136,375	$126,254	$86,185	$785,716

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance

Attachment 1
April 11-March 12 GCR Reconciliation

No.	Description (a)	Reference (b)	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Total
14	**Storage Variable Product Costs**		$835,207	$809,481	$485,800	$1,237,930	$393,029	$551,050	$659,871	$1,424,190	$2,865,627	$6,482,287	$6,312,515	($620,294)	$21,436,694
15	Less: Balancing Related LNG Commodity (to DAC)		($23,866)	($35,366)	($26,533)	($26,746)	($25,968)	($18,623)	($36,509)	($24,094)	($39,388)	($278,093)	($54,605)	$6,799	($582,992)
16	Plus: Supply Related LNG O&M Costs		$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$430,129
17	Allowable Working Capital Costs	(14) + (15) + (16)	$847,185	$809,959	$495,111	$1,247,029	$402,905	$568,271	$659,206	$1,435,940	$2,862,084	$6,240,038	$6,293,755	($577,652)	$21,283,831
18	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
19	Working Capital Requirement	[(17) * (18)] / 365	$56,634	$54,145	$33,098	$83,363	$26,934	$37,989	$44,067	$95,992	$191,328	$417,142	$420,733	($38,616)	
20	Cost of Capital	Rate Case	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.23%	7.23%	7.23%	7.23%	7.23%	
21	Return on Working Capital Requirement	(19) * (20)	$4,228	$4,042	$2,471	$6,224	$2,011	$2,836	$3,290	$6,940	$13,833	$30,159	$30,419	($2,792)	
22	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
23	Interest Expense	(19) * (22)	$1,391	$1,330	$813	$2,048	$662	$933	$1,082	$2,131	$4,247	$9,261	$9,340	($857)	
24	Taxable Income	(19) - (23)	$2,837	$2,712	$1,658	$4,176	$1,349	$1,903	$2,208	$4,809	$9,586	$20,899	$21,079	($1,935)	
25	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
26	Return and Tax Requirement	(24) / (25)	$4,365	$4,173	$2,551	$6,425	$2,076	$2,928	$3,396	$7,399	$14,747	$32,152	$32,429	($2,976)	
27	**Storage Var. Product Working Capital Requir.**	(23) + (26)	$5,756	$5,503	$3,364	$8,472	$2,737	$3,861	$4,479	$9,530	$18,994	$41,413	$41,769	($3,834)	$142,044
1	**Storage Variable Non-Product Costs**		$73,085	$64,721	$45,502	$69,955	$70,420	$61,275	$50,676	$46,324	$68,016	$122,005	$29,761	$79,410	$781,151
2	Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Allowable Working Capital Costs	(1) - (2)	$73,085	$64,721	$45,502	$69,955	$70,420	$61,275	$50,676	$46,324	$68,016	$122,005	$29,761	$79,410	$781,151
4	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$4,886	$4,327	$3,042	$4,676	$4,708	$4,096	$3,388	$3,097	$4,547	$8,156	$1,989	$5,309	
6	Cost of Capital	Rate Case	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.23%	7.23%	7.23%	7.23%	7.23%	
7	Return on Working Capital Requirement	(5) * (6)	$365	$323	$227	$349	$351	$306	$253	$224	$329	$590	$144	$384	
8	Weighted Cost of Debt	Rate Case	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.22%	2.22%	2.22%	2.22%	2.22%	
9	Interest Expense	(5) * (8)	$120	$106	$75	$115	$116	$101	$83	$69	$101	$181	$44	$118	
10	Taxable Income	(7) - (9)	$245	$217	$152	$234	$236	$205	$170	$155	$228	$409	$100	$266	
11	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
12	Return and Tax Requirement	(10) / (11)	$377	$333	$234	$360	$363	$316	$261	$239	$350	$629	$153	$409	
13	**Storage Variable Non-product WC Requir.**	(9) + (12)	$497	$440	$309	$475	$478	$416	$344	$307	$451	$810	$198	$527	$5,253

National Grid
Rhode Island - Gas
Deferred Gas Cost Balance

Attachment 1
April 11-March 12 GCR Reconciliation

Line No.	Rate Class (a)	Apr-11 (b) actual	May-11 (c) actual	Jun-11 (d) actual	Jul-11 (e) actual	Aug-11 (f) actual	Sep-11 (g) actual	Oct-11 (h) actual	Nov-11 (i) actual	Dec-11 (j) actual	Jan-12 (k) actual	Feb-12 (l) actual	Mar-12 (m) actual	Apr - Mar (n)
1	**SALES (dth)**													
2	Residential Non-Heating	60,827	42,710	35,440	29,795	25,513	28,158	28,795	44,902	58,419	74,486	80,015	74,243	583,302
3	Residential Non-Heating Low Income	2,654	1,609	945	705	596	638	667	1,359	1,937	2,622	2,598	2,895	19,228
4	Residential Heating	1,843,901	913,059	514,509	367,950	338,829	351,381	377,486	960,000	1,459,048	2,163,628	2,410,188	2,120,996	13,820,976
5	Residential Heating Low Income	220,131	115,189	71,759	51,639	42,811	45,777	48,508	114,787	155,722	228,341	228,599	220,671	1,543,932
6	Small C&I	275,546	123,393	68,788	54,697	46,827	46,018	47,648	122,071	197,162	331,804	365,172	314,636	1,993,763
7	Medium C&I	349,862	198,349	119,313	121,760	55,517	94,239	97,191	198,585	282,086	399,576	460,864	377,195	2,754,537
8	Large LLF	88,541	30,116	26,427	10,951	11,406	5,507	11,795	42,525	64,369	89,953	96,183	86,574	564,349
9	Large HLF	24,915	16,658	14,962	14,957	15,242	15,261	14,027	21,365	20,964	25,224	24,057	26,950	234,581
10	Extra Large LLF	4,090	2,759	1,770	881	1,063	701	4,792	5,735	7,085	7,032	9,417	9,066	54,392
11	Extra Large HLF	17,184	14,335	12,683	12,210	10,280	12,906	11,450	14,479	15,102	14,550	31,879	23,367	190,426
	Total Sales	2,887,652	1,458,175	866,598	665,545	548,084	600,586	642,361	1,525,810	2,261,894	3,337,216	3,708,971	3,256,593	21,759,485
12	**TSS**													
13	Medium	3,970	2,868	780	(24)	257	294	601	1,160	1,292	5,510	7,494	5,171	29,374
14	Large LLF	2,223	571	171	9	8	1	2	7	264	6,486	9,077	6,272	25,091
15	Large HLF	1,076	1,909	2,148	996	1,372	229	212	54	256	1,154	0	0	9,406
16	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
18	**Total TSS**	7,269	5,349	3,099	980	1,637	525	815	1,221	1,811	13,150	16,570	11,444	63,871
19	**FT-2 TRANSPORTATION**													
20	FT-2 Medium	132,781	82,783	54,623	41,849	35,737	39,442	55,125	84,497	124,415	173,238	198,009	169,456	1,191,953
21	FT-2 Large LLF	88,452	55,989	14,153	15,487	12,410	15,061	19,760	55,136	88,932	120,006	148,698	123,509	757,592
22	FT-2 Large HLF	24,528	18,634	15,697	15,021	13,286	14,111	13,712	19,363	23,314	25,100	25,571	26,395	234,732
23	FT-2 Extra Large LLF	8,526	3,841	2,005	2,063	1,424	1,288	4,316	3,048	4,804	5,464	159,674	151,682	348,136
24	FT-2 Extra Large HLF	17,947	13,729	12,681	10,663	10,998	11,069	9,634	12,705	12,707	13,687	12,176	18,361	156,358
25	**Total FT-2 Transportation**	272,234	174,976	99,159	85,083	73,855	80,970	102,547	174,749	254,172	337,494	544,128	489,404	2,688,771
26	**Sales & FT-2 THROUGHPUT**													
27	Residential Non-Heating	60,827	42,710	35,440	29,795	25,513	28,158	28,795	44,902	58,419	74,486	80,015	74,243	583,302
28	Residential Non-Heating Low Income	2,654	1,609	945	705	596	638	667	1,359	1,937	2,622	2,598	2,895	19,228
29	Residential Heating	1,843,901	913,059	514,509	367,950	338,829	351,381	377,486	960,000	1,459,048	2,163,628	2,410,188	2,120,996	13,820,976
30	Residential Heating Low Income	220,131	115,189	71,759	51,639	42,811	45,777	48,508	114,787	155,722	228,341	228,599	220,671	1,543,932
31	Small C&I	275,546	123,393	68,788	54,697	46,827	46,018	47,648	122,071	197,162	331,804	365,172	314,636	1,993,763
32	Medium C&I	486,613	284,000	174,717	163,584	91,511	133,975	152,316	284,241	407,793	578,324	666,366	551,822	3,975,263
33	Large LLF	179,216	86,676	40,752	26,448	23,825	20,570	31,555	97,668	153,565	216,444	253,957	216,356	1,347,030
34	Large HLF	50,520	37,201	32,807	30,973	29,900	29,600	27,739	40,783	44,533	51,478	49,627	53,345	478,507
35	Extra Large LLF	12,616	6,600	3,775	2,945	2,487	1,989	9,108	8,784	11,889	12,496	169,091	160,748	402,528
36	Extra Large HLF	35,131	28,064	25,364	22,872	21,278	23,975	21,084	27,184	27,809	28,237	44,055	41,728	346,783
37	**Total Sales & FT-2 Throughput**	3,167,155	1,638,500	968,857	751,608	623,577	682,081	744,907	1,701,779	2,517,877	3,687,860	4,269,669	3,757,440	24,511,311
38	**FT-1 TRANSPORTATION**													
39	FT-1 Medium	68,251	34,922	34,237	26,402	30,027	32,048	43,552	70,505	71,907	84,346	126,067	76,260	698,523
40	FT-1 Large LLF	103,539	38,937	17,336	15,214	18,741	24,007	38,099	112,279	126,331	150,594	240,868	130,914	1,016,860
41	FT-1 Large HLF	45,009	35,881	31,477	25,870	30,954	30,335	32,424	38,799	39,984	43,691	58,511	42,388	455,323
42	FT-1 Extra Large LLF	104,731	45,827	12,885	12,768	15,780	19,228	37,595	112,161	108,994	120,681	42,743	(7,662)	625,731
43	FT-1 Extra Large HLF	408,779	351,634	365,278	329,704	373,896	345,600	349,002	404,370	417,990	435,051	537,893	430,383	4,749,580
44	Default	6,143	3,930	1,961	4,023	1,378	1,818	2,170	4,486	5,240	5,962	9,219	5,189	51,519
45	**Total FT-1 Transportation**	736,452	511,131	463,174	413,982	470,777	453,035	502,841	742,601	770,446	840,325	1,015,301	677,471	7,597,536
46	**Total THROUGHPUT**													
47	Residential Non-Heating	60,827	42,710	35,440	29,795	25,513	28,158	28,795	44,902	58,419	74,486	80,015	74,243	583,302
48	Residential Non-Heating Low Income	2,654	1,609	945	705	596	638	667	1,359	1,937	2,622	2,598	2,895	19,228
49	Residential Heating	1,843,901	913,059	514,509	367,950	338,829	351,381	377,486	960,000	1,459,048	2,163,628	2,410,188	2,120,996	13,820,976
50	Residential Heating Low Income	220,131	115,189	71,759	51,639	42,811	45,777	48,508	114,787	155,722	228,341	228,599	220,671	1,543,932
51	Small C&I	275,546	123,393	68,788	54,697	46,827	46,018	47,648	122,071	197,162	331,804	365,172	314,636	1,993,763
52	Medium C&I	554,864	318,922	208,954	189,986	121,538	166,023	195,868	354,746	479,700	662,670	792,433	628,082	4,673,786
53	Large LLF	282,755	125,613	58,087	41,662	42,566	44,577	69,654	209,947	279,896	367,039	494,826	347,270	2,363,891
53	Large HLF	95,529	73,082	64,285	56,843	60,854	59,935	60,163	79,582	84,517	95,169	108,139	95,733	933,830
54	Extra Large LLF	117,347	52,426	16,660	15,713	18,268	21,217	46,703	120,944	120,883	133,177	211,833	153,086	1,028,259
55	Extra Large HLF	443,910	379,698	390,642	352,576	395,175	369,575	370,086	431,555	445,798	463,288	581,948	472,111	3,096,363
56	Default	6,143	3,930	1,961	4,023	1,378	1,818	2,170	4,486	5,240	5,962	9,219	5,189	51,519
57	**Total Throughput**	3,903,607	2,149,631	1,432,031	1,165,590	1,094,353	1,135,116	1,247,749	2,444,380	3,288,323	4,528,185	5,284,970	4,434,912	32,108,848

actual dth

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

Line No.		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
		30	31	31	28	31	30	31	30	31	31	30	31
		forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast
1	I. Fixed Cost Deferred												
2	Beginning Balance	$10,697,488	$10,410,463	$8,204,311	$3,339,024	($1,644,543)	($5,627,975)	($7,763,366)	($7,983,639)	($6,829,029)	($5,146,133)	($3,328,599)	($1,545,859)
3	Fixed Costs (net of cap rel)	$3,333,941	$3,334,584	$3,333,245	$3,331,316	$3,333,245	$3,339,235	$3,339,878	$3,339,235	$3,339,878	$3,339,878	$3,339,235	$3,339,878
4	Storage Costs to Marketer FT-2	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)	($98,225)
5	Working Capital	$22,112	$22,116	$22,107	$22,094	$22,107	$22,139	$22,143	$22,139	$22,143	$22,143	$22,139	$22,143
6	LNG Demand to DAC	($51,187)	($51,187)	($51,187)	($51,187)	($51,187)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)	($52,389)
7	Supply Related LNG O & M	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549
8	Total Supply Fixed Costs	$3,258,189	$3,258,837	$3,257,489	$3,255,547	$3,257,489	$3,262,308	$3,262,956	$3,262,308	$3,262,956	$3,262,956	$3,262,308	$3,262,956
9	Fixed - Collections	($2,798,449)	($5,091,532)	($7,745,566)	($7,856,592)	($6,853,729)	($5,007,490)	($3,091,541)	($1,716,760)	($1,190,373)	($1,057,592)	($1,093,732)	($1,345,668)
10	NGPMP Credits	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)
11	Prelim. Ending Balance	$10,773,895	$8,194,435	$3,332,900	($1,645,355)	($5,624,116)	($7,756,490)	($7,975,284)	($6,821,424)	($5,139,780)	($3,324,103)	($1,543,356)	($11,905)
12	Month's Average Balance	$10,735,692	$9,302,449	$5,768,605	$846,835	($3,634,330)	($6,692,232)	($7,869,325)	($7,402,531)	($5,984,404)	($4,235,118)	($2,435,978)	($778,882)
13	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
14	Interest Applied	$11,030	$9,876	$6,124	$812	($3,858)	($6,876)	($8,354)	($7,605)	($6,353)	($4,496)	($2,503)	($827)
15	GPIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Marketer Reconcilation	($374,462)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17													
18	Fixed Ending Balance	$10,410,463	$8,204,311	$3,339,024	($1,644,543)	($5,627,975)	($7,763,366)	($7,983,639)	($6,829,029)	($5,146,133)	($3,328,599)	($1,545,859)	($12,731)
19													
20													
21	II. Variable Cost Deferred												
22	Beginning Balance	($10,210,487)	($6,534,239)	($423,979)	$5,057,178	$5,684,743	$4,367,736	$854,959	($1,536,061)	($2,502,198)	($2,511,997)	($2,219,779)	($1,970,861)
23	Variable Costs	$10,716,897	$19,113,463	$25,301,637	$20,756,863	$16,228,514	$9,280,808	$5,461,441	$3,319,290	$2,914,655	$2,871,784	$2,921,254	$5,268,858
24	Supply Related LNG to DAC	($19,079)	($92,451)	($63,528)	($36,432)	($19,789)	($19,079)	($19,789)	($19,698)	($20,861)	($20,861)	($20,112)	($20,928)
25	Supply Related LNG O & M	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844
26	Inventory Financing - LNG	$32,951	$29,498	$27,124	$25,763	$25,024	$24,312	$30,412	$35,491	$34,712	$33,933	$35,781	$35,896
27	Inventory Financing - UG	$143,097	$136,055	$105,704	$83,143	$82,067	$102,549	$123,969	$138,044	$141,233	$142,486	$143,825	$143,402
28	Working Capital	$71,181	$126,377	$167,606	$137,647	$107,727	$61,658	$36,324	$22,119	$19,428	$19,144	$19,477	$35,040
29	Total Variable Costs	$10,980,892	$19,348,786	$25,574,387	$21,002,828	$16,459,387	$9,486,091	$5,668,202	$3,531,090	$3,125,011	$3,082,330	$3,136,069	$5,498,111
30	Variable - Collections	($7,296,047)	($13,234,835)	($20,095,688)	($20,380,411)	($17,781,727)	($13,001,550)	($8,058,861)	($4,495,153)	($3,132,149)	($2,787,602)	($2,884,999)	($3,532,630)
31	Deferred Responsibility	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Prelim. Ending Balance	($6,525,642)	($420,288)	$5,054,720	$5,679,595	$4,362,403	$852,278	($1,535,700)	($2,500,125)	($2,509,336)	($2,217,269)	($1,968,709)	($5,379)
33	Month's Average Balance	($8,368,064)	($3,477,263)	$2,315,370	$5,368,387	$5,023,573	$2,610,007	($340,370)	($2,018,093)	($2,505,767)	($2,364,633)	($2,094,244)	($988,120)
34	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
35	Interest Applied	($8,597)	($3,692)	$2,458	$5,148	$5,333	$2,682	($361)	($2,073)	($2,660)	($2,510)	($2,152)	($1,049)
36	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Variable Ending Balance	($6,534,239)	($423,979)	$5,057,178	$5,684,743	$4,367,736	$854,959	($1,536,061)	($2,502,198)	($2,511,997)	($2,219,779)	($1,970,861)	($6,429)
38													
39													
40	**GCR Deferred Summary**												
41	Beginning Balance	$487,002	$3,876,224	$7,780,331	$8,396,202	$4,040,200	($1,260,238)	($6,908,406)	($9,519,700)	($9,331,227)	($7,658,130)	($5,548,378)	($3,516,720)
42	Gas Costs	$13,771,327	$22,459,130	$28,642,163	$24,098,634	$19,587,042	$12,664,603	$8,872,690	$6,749,140	$6,346,395	$6,303,999	$6,356,761	$8,703,884
43	Working Capital	$93,293	$148,493	$189,713	$159,741	$129,834	$83,796	$58,467	$44,258	$41,571	$41,287	$41,616	$57,183
44	Total Costs	$13,864,619	$22,607,623	$28,831,876	$24,258,375	$19,716,876	$12,748,399	$8,931,157	$6,793,398	$6,387,966	$6,345,285	$6,398,377	$8,761,067
45	Collections	($10,094,496)	($18,326,367)	($27,841,254)	($28,237,003)	($24,635,456)	($18,009,040)	($11,150,402)	($6,211,913)	($4,322,522)	($3,845,194)	($3,978,731)	($4,878,298)
46	NGPMP Credits	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)	($383,333)
46	Prelim. Ending Balance	$4,257,125	$8,157,480	$8,770,953	$4,417,574	($878,380)	($6,520,879)	($9,127,651)	($8,938,215)	($7,265,783)	($5,158,038)	($3,128,732)	$366,049
47	Month's Average Balance	$2,372,063	$6,016,852	$8,275,642	$6,406,888	$1,580,910	($3,890,559)	($8,018,029)	($9,228,958)	($8,298,505)	($6,408,084)	($4,338,555)	($1,575,335)
48	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
49	Interest Applied	$2,432	$6,184	$8,582	$5,960	$1,475	($4,194)	($8,716)	($9,679)	($9,014)	($7,007)	($4,654)	($1,876)
50	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51													
52	**Ending Bal. W/ Interest**	$3,876,224	$7,780,331	$8,396,202	$4,040,200	($1,260,238)	($6,908,406)	($9,519,700)	($9,331,227)	($7,658,130)	($5,548,378)	($3,516,720)	$\boxed{\textbf{(\$19,160)}}$

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2012

Residential Heating:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: DAC	DAC: ISR	EnergyEff
	600	$845	$892	($47)	-5.3%	$0	($73)	$26	$0	($113)
	664	$919	$971	($52)	-5.3%	$0	($81)	$29	$0	$0
	730	$996	$1,053	($57)	-5.4%	$0	($89)	$32	$0	$0
	794	$1,069	$1,131	($62)	-5.5%	$0	($97)	$35	$0	$0
	857	$1,138	$1,205	($67)	-5.6%	$0	($105)	$38	$0	$0
Average Customer	**922**	**$1,209**	**$1,281**	**($72)**	**-5.6%**	**$0**	**($113)**	**$40**	**$0**	**$0**
	987	$1,280	$1,357	($77)	-5.7%	$0	($120)	$43	$0	$0
	1,051	$1,349	$1,431	($82)	-5.7%	$0	($128)	$46	$0	$0
	1,114	$1,415	$1,502	($87)	-5.8%	$0	($136)	$49	$0	$0
	1,180	$1,484	$1,577	($92)	-5.9%	$0	($144)	$52	$0	$0
	1,247	$1,554	$1,652	($98)	-5.9%	$0	($152)	$55	$0	$0

Residential Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EnergyEff
	600	$808	$855	($47)	-5.5%	$0	($73)	$26	$0	$0
	664	$880	$931	($52)	-5.6%	$0	($81)	$29	$0	$0
	730	$954	$1,011	($57)	-5.6%	$0	($89)	$32	$0	$0
	794	$1,024	$1,086	($62)	-5.7%	$0	($97)	$35	$0	$0
	857	$1,091	$1,158	($67)	-5.8%	$0	($105)	$38	$0	$0
Average Customer	**922**	**$1,160**	**$1,232**	**($72)**	**-5.8%**	**$0**	**($113)**	**$40**	**$0**	**$0**
	987	$1,229	$1,306	($77)	-5.9%	$0	($120)	$43	$0	$0
	1,051	$1,296	$1,379	($82)	-6.0%	$0	($128)	$46	$0	$0
	1,114	$1,361	$1,448	($87)	-6.0%	$0	($136)	$49	$0	$0
	1,180	$1,428	$1,521	($92)	-6.1%	$0	($144)	$52	$0	$0
	1,247	$1,497	$1,594	($98)	-6.1%	$0	($152)	$55	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2012

Residential Non-Heating:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: DAC	DAC: ISR	EnergyEff
	123	$265	$275	($10)	-3.6%	$0	($16)	$6	$0	$0
	137	$282	$293	($11)	-3.8%	$0	($17)	$6	$0	$0
	147	$294	$306	($12)	-3.9%	$0	($19)	$7	$0	$0
	161	$310	$323	($13)	-4.0%	$0	($20)	$8	$0	$0
	176	$328	$342	($14)	-4.1%	$0	($22)	$8	$0	$0
Average Customer	**189**	**$343**	**$358**	**($15)**	**-4.2%**	**$0**	**($24)**	**$9**	**$0**	**$0**
	202	$359	$375	($16)	-4.3%	$0	($26)	$9	$0	$0
	217	$376	$394	($17)	-4.4%	$0	($28)	$10	$0	$0
	231	$393	$411	($18)	-4.5%	$0	($29)	$11	$0	$0
	241	$405	$424	($19)	-4.6%	$0	($31)	$11	$0	$0
	256	$423	$443	($21)	-4.6%	$0	($33)	$12	$0	$0

Residential Non-Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: DAC	DAC: ISR	EnergyEff
	123	$248	$258	($10)	-3.8%	$0	($16)	$6	$8	$0
	137	$264	$275	($11)	-4.0%	$0	($17)	$6	$9	$0
	147	$276	$288	($12)	-4.1%	$0	($19)	$7	$10	$0
	161	$292	$305	($13)	-4.2%	$0	($20)	$8	$11	$0
	176	$309	$323	($14)	-4.4%	$0	($22)	$8	$12	$0
Average Customer	**189**	**$324**	**$339**	**($15)**	**-4.5%**	**$0**	**($24)**	**$9**	**$13**	**$0**
	202	$339	$355	($16)	-4.6%	$0	($26)	$9	$14	$0
	217	$356	$373	($17)	-4.7%	$0	($28)	$10	$15	$0
	231	$372	$390	($19)	-4.7%	$0	($29)	$11	$16	$0
	241	$383	$402	($19)	-4.8%	$0	($31)	$11	$16	$0
	256	$400	$421	($21)	-4.9%	$0	($33)	$12	$17	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2012

C & I Small:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	824	$1,245	$1,310	($65)	-5.0%	$0	($101)	$36	$0	$0
	916	$1,346	$1,419	($72)	-5.1%	$0	($112)	$39	$0	$0
	1,003	$1,441	$1,521	($79)	-5.2%	$0	($122)	$43	$0	$0
	1,092	$1,535	$1,622	($86)	-5.3%	$0	($133)	$47	$0	$0
	1,179	$1,623	$1,717	($93)	-5.4%	$0	($144)	$51	$0	$0
Average Customer	**1,269**	**$1,714**	**$1,814**	**($100)**	**-5.5%**	**$0**	**($155)**	**$55**	**$0**	**$0**
	1,359	$1,805	$1,913	($107)	-5.6%	$0	($166)	$59	$0	$0
	1,447	$1,894	$2,008	($114)	-5.7%	$0	($177)	$62	$0	$0
	1,535	$1,981	$2,103	($121)	-5.8%	$0	($187)	$66	$0	$0
	1,622	$2,068	$2,196	($128)	-5.8%	$0	($198)	$70	$0	$0
	1,715	$2,161	$2,296	($135)	-5.9%	$0	($209)	$74	$0	$0

C & I Medium:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	7,117	$7,947	$8,512	($565)	-6.6%	$0	($869)	$304	$0	$0
	7,884	$8,726	$9,352	($626)	-6.7%	$0	($963)	$337	$0	$0
	8,649	$9,503	$10,190	($687)	-6.7%	$0	($1,056)	$369	$0	$0
	9,416	$10,282	$11,030	($748)	-6.8%	$0	($1,150)	$402	$0	$0
	10,185	$11,063	$11,872	($809)	-6.8%	$0	($1,244)	$435	$0	$0
Average Customer	**10,950**	**$11,840**	**$12,709**	**($869)**	**-6.8%**	**$0**	**($1,337)**	**$468**	**$0**	**$0**
	11,715	$12,617	$13,547	($930)	-6.9%	$0	($1,430)	$500	$0	$0
	12,484	$13,398	$14,389	($991)	-6.9%	$0	($1,524)	$533	$0	$0
	13,251	$14,176	$15,228	($1,052)	-6.9%	$0	($1,618)	$566	$0	$0
	14,016	$14,953	$16,066	($1,113)	-6.9%	$0	($1,711)	$598	$0	$0
	14,783	$15,732	$16,906	($1,174)	-6.9%	$0	($1,805)	$631	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2012

C & I LLF Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	37,532	$38,473	$42,977	($4,504)	-10.5%	$0	($4,583)	$79	$0	$0
	41,573	$42,461	$47,449	($4,989)	-10.5%	$0	($5,076)	$87	$0	$0
	45,616	$46,450	$51,924	($5,474)	-10.5%	$0	($5,570)	$96	$0	$0
	49,660	$50,440	$56,399	($5,959)	-10.6%	$0	($6,063)	$104	$0	$0
	53,699	$54,426	$60,869	($6,444)	-10.6%	$0	($6,557)	$113	$0	$0
Average Customer	**57,742**	**$58,415**	**$65,344**	**($6,929)**	**-10.6%**	**$0**	**($7,050)**	**$121**	**$0**	**$0**
	61,785	$62,404	$69,818	($7,414)	-10.6%	$0	($7,544)	$130	$0	$0
	65,824	$66,390	$74,288	($7,899)	-10.6%	$0	($8,037)	$138	$0	$0
	69,868	$70,380	$78,764	($8,384)	-10.6%	$0	($8,531)	$147	$0	$0
	73,911	$74,369	$83,238	($8,869)	-10.7%	$0	($9,025)	$155	$0	$0
	77,952	$78,356	$87,711	($9,354)	-10.7%	$0	($9,518)	$164	$0	$0

C & I HLF Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	37,970	$33,379	$38,118	($4,739)	-12.4%	$7,632	($4,826)	$87	$0	$0
	42,061	$36,820	$42,070	($5,249)	-12.5%	$8,299	($5,346)	$97	$0	$0
	46,151	$40,261	$46,020	($5,760)	-12.5%	$8,966	($5,866)	$106	$0	$0
	50,240	$43,700	$49,970	($6,270)	-12.5%	$9,632	($6,386)	$116	$0	$0
	54,329	$47,140	$53,920	($6,780)	-12.6%	$10,299	($6,905)	$125	$0	$0
Average Customer	**58,418**	**$50,579**	**$57,870**	**($7,291)**	**-12.6%**	**$10,966**	**($7,425)**	**$134**	**$0**	**$0**
	62,508	$54,020	$61,821	($7,801)	-12.6%	$11,633	($7,945)	$144	$0	$0
	66,596	$57,459	$65,770	($8,311)	-12.6%	$12,300	($8,464)	$153	$0	$0
	70,686	$60,898	$69,720	($8,822)	-12.7%	$12,966	($8,984)	$163	$0	$0
	74,775	$64,338	$73,670	($9,332)	-12.7%	$13,633	($9,504)	$172	$0	$0
	78,867	$67,780	$77,623	($9,843)	-12.7%	$14,300	($10,024)	$181	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2012

C & I LLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	189,450	$162,073	$184,940	($22,867)	-12.4%	$0	($23,132)	$265	$0	$0
	209,855	$179,142	$204,471	($25,329)	-12.4%	$0	($25,623)	$294	$0	$0
	230,255	$196,206	$223,998	($27,792)	-12.4%	$0	($28,114)	$322	$0	$0
	250,655	$213,271	$243,525	($30,254)	-12.4%	$0	($30,605)	$351	$0	$0
	271,059	$230,338	$263,055	($32,717)	-12.4%	$0	($33,096)	$379	$0	$0
Average Customer	**291,462**	**$247,405**	**$282,584**	**($35,179)**	**-12.4%**	**$0**	**($35,588)**	**$408**	**$0**	**$0**
	311,865	$264,472	$302,114	($37,642)	-12.5%	$0	($38,079)	$437	$0	$0
	332,269	$281,539	$321,644	($40,105)	-12.5%	$0	($40,570)	$465	$0	$0
	352,669	$298,604	$341,171	($42,567)	-12.5%	$0	($43,061)	$494	$0	$0
	373,069	$315,668	$360,698	($45,029)	-12.5%	$0	($45,552)	$522	$0	$0
	393,474	$332,737	$380,229	($47,492)	-12.5%	$0	($48,043)	$551	$0	$0

C & I HLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	184,661	$149,839	$173,069	($23,230)	-13.4%	$0	($23,470)	$240	$0	$0
	204,549	$165,589	$191,321	($25,732)	-13.4%	$0	($25,998)	$266	$0	$0
	224,435	$181,337	$209,571	($28,234)	-13.5%	$0	($28,526)	$292	$0	$0
	244,321	$197,086	$227,821	($30,736)	-13.5%	$0	($31,053)	$318	$0	$0
	264,206	$212,833	$246,071	($33,237)	-13.5%	$0	($33,581)	$343	$0	$0
Average Customer	**284,094**	**$228,583**	**$264,322**	**($35,739)**	**-13.5%**	**$0**	**($36,108)**	**$369**	**$0**	**$0**
	303,982	$244,333	$282,574	($38,241)	-13.5%	$0	($38,636)	$395	$0	$0
	323,867	$260,081	$300,823	($40,742)	-13.5%	$0	($41,164)	$421	$0	$0
	343,753	$275,829	$319,073	($43,244)	-13.6%	$0	($43,691)	$447	$0	$0
	363,639	$291,577	$337,323	($45,746)	-13.6%	$0	($46,219)	$473	$0	$0
	383,527	$307,327	$355,575	($48,248)	-13.6%	$0	($48,746)	$499	$0	$0

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

Item	Reference	Proposed	Billing Units
FT-2 Demand	**AEL-5 pg 2**	**$7.3770**	Dth/Mth
Weighted Average Upstream Pipeline Transportation Cost	EDA - 4	**$0.8601**	Per Therm of capacity

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

Line No.	Description	Source Reference	Line #	Amount	
1	Storage Fixed Costs	**AEL-1 pg 4**	Line 55	$11,398,130	
	Less:				
2	LNG Demand to DAC	**AEL-1 pg 2**	Line 5	($622,659)	
3	Credits			$0	
4	Refunds			$0	
5	Total Credits	sum [(2):(4)]		($622,659)	
	Plus:				
6	Supply Related LNG O&M Costs	Rate Case		$618,591	
7	Working Capital Requirement	**AEL-1 pg 9**	Line 45	$75,561	
8	Total Additions	sum [(6):(7)]		$694,152	
9	Total Storage Fixed Costs	(1) + (5) + (8)		$11,469,622	
	Inventory Financing				
10	Underground	**AEL-1 pg 10**	Line 12	$1,485,575	
11	LNG	**AEL-1 pg 10**	Line 25	$370,897	
12	Total Storage Fixed Costs	(9) + (10) + (11)		$13,326,094	
13	LNG Storage MDQ (Dth)			111,857	
14	AGT	EDA-4		31,641	
15	TENN	EDA-4		10,836	
16	Total Storage MDQ	sum [(13):(15)]		154,334	
17	Storage MDQ X 12 Months	(16) *12		1,852,008	MDCQ Dth
18	**FT- 2 Demand Rate**	(12) / (17)		**$7.1955**	per MDCQ Dth
19	Uncollectible %	Docket 3943		2.46%	
20	Total FT-2 Demand Rate adjusted for Uncollectibles	(18) / [(1 - (19)]		**$7.3770**	per MDCQ Dth

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

Line No.	Description	Source Reference	Line #	Amount	
1	**FT- 2 Demand Rate**	**AEL-5 pg 2**	Line 18	**$7.1955**	per MDCQ Dth
2	MDQ-U	Mkter MDQ Forecast		3,774	
3	MDQ-P	Mkter MDQ Forecast		9,877	
4	Marketer MDQs	(2) + (3)		13,651	Dth/Mth
5	**FT-2 Storage Costs**	(19) x (20) x 12 Months		**$1,178,704**	

RI Gas Company
Capacity Assignment Table

		% of Peak Day Requirement				% of Total Capacity		
		Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking
HLF	Res - Non-Heating	60.0%	11.0%	29.0%	100.0%	1.8%	1.5%	1.5%
HLF	Res - Non-Heating LI	60.0%	11.0%	29.0%	100.0%			
LLF	Res - Heating	53.0%	13.0%	34.0%	100.0%	59.8%	60.7%	60.7%
LLF	Res - Heating LI	53.0%	13.0%	34.0%	100.0%			
LLF	Small	53.0%	13.0%	34.0%	100.0%	8.1%	8.3%	8.3%
LLF	Med	53.0%	13.0%	34.0%	100.0%	9.5%	9.1%	9.1%
LLF	Large Low Load	53.0%	13.0%	34.0%	100.0%	2.4%	2.6%	2.6%
HLF	Large High Load	60.0%	11.0%	29.0%	100.0%	0.6%	0.3%	0.3%
LLF	XL Low Load	53.0%	13.0%	34.0%	100.0%	0.2%	0.3%	0.3%
HLF	XL High Load	60.0%	11.0%	29.0%	100.0%	0.5%	0.4%	0.4%

HLF	High Load Factor	60.0%	11.0%	29.0%	100.0%	5.8%	4.6%	4.6%
LLF	Low Load Factor	53.0%	13.0%	34.0%	100.0%	94.2%	95.4%	95.4%
	Total	54.0%	13.0%	33.0%	100.0%	100.0%	100.0%	100.0%

2010/11 & 2011/2012 Annual Marketer Reconciliation

	# of days	Tetco ELA/Algonquin	Tetco WLA/Algonquin	Tennessee Zone 1 to NEGC	Tetco STX/Algonquin	Algonquin @ Lambertville, NJ	Columbia (Maumee/Downington)	Total
2010-2010 Marketer Reconciliation								
Month of activity								
Nov-10	30	165,000	249,030	249,000	121,320	81,420	26,880	892,650
Dec-10	31	170,500	263,035	280,178	125,364	84,134	27,311	950,522
Jan-11	31	170,500	263,035	286,347	116,157	84,134	26,381	946,554
Feb-11	28	154,000	238,000	265,552	100,296	75,992	23,828	857,668
Mar-11	31	170,500	263,500	294,500	125,364	84,134	28,892	966,890
Apr-11	30	171,840	253,440	285,000	120,210	81,420	27,630	939,540
May-11	31	179,831	262,973	294,376	119,815	84,134	28,551	969,680
Jun-11	30	179,730	254,490	285,000	111,450	81,420	26,580	938,670
Jul-11	31	186,217	262,756	294,500	116,157	84,134	26,877	970,641
Aug-11	31	188,511	262,756	294,500	118,203	84,134	26,660	974,764
Sep-11	30	190,620	255,000	285,000	108,840	81,420	24,090	944,970
Oct-11	31	197,408	263,500	294,500	111,166	84,134	24,893	975,601
		2,124,657	3,091,515	3,408,453	1,394,342	990,610	318,573	11,328,150
Approved								
System Average		$0.9677	$0.9677	$0.9677	$0.9677	$0.9677	$0.9677	
Path $1.1380			$1.2116	$1.0050	$1.3453	$0.7824	$0.6872	
Credit/Surcharge		($0.1703)	($0.2439)	($0.0373)	($0.3776)	$0.1853	$0.2805	
Revised								
System Average		$0.9843	$0.9843	$0.9843	$0.9843	$0.9843	$0.9843	
Path		$1.1331	$1.2065	$1.1003	$1.3396	$0.7824	$0.6862	
Credit/Surcharge		($0.1489)	($0.2222)	($0.1160)	($0.3554)	$0.2018	$0.2980	
Variance- approved Surcharge/Credit vs. Revised Surcharge/C		$0.0215	$0.0217	($0.0787)	$0.0222	$0.0166	$0.0175	
Annual MDCQ		2,124,657	3,091,515	3,408,453	1,394,342	990,610	318,573	11,328,150
Marketer Reconciliation Adjustment		$45,592	$67,045	($268,183)	$30,961	$16,419	$5,580	($102,587)
2011-2012 Marketer Reconciliation								
Month of activity								
Nov-11	30	195,000	255,000	285,000	115,826	81,420	6,424	938,670
Dec-11	31	201,531	263,500	294,531	120,869	84,134	15,314	979,879
Jan-12	31	201,526	263,513	294,460	121,614	84,105	20,521	985,738
Feb-12	29	188,500	246,500	275,471	114,840	78,735	26,825	930,871
Mar-12	31	201,461	263,500	294,500	120,807	84,086	15,318	979,672
Apr-12	30	195,000	254,970	285,030	117,600	81,450	18,840	952,890
May-12	31	201,500	263,469	294,500	122,109	84,165	22,599	988,342
Jun-12	30	195,030	255,000	285,030	118,320	81,450	22,680	957,510
Jul-12	31	201,500	263,500	294,469	122,636	84,134	26,288	992,527
Aug-12	31	201,469	263,469	294,469	124,062	84,134	37,231	1,004,834
Sep-12	30	194,970	254,970	284,970	120,060	81,420	36,030	972,420
Oct-12	31	201,469	263,469	294,469	124,062	84,134	37,231	1,004,834
		2,378,957	3,110,860	3,476,899	1,442,805	993,367	285,300	11,688,187
Approved								
System Average		$0.9617	$0.9617	$0.9617	$0.9617	$0.9617	$0.9617	
Path $0.9584			$1.1556	$1.2849	$1.3372	$0.8669	$0.6419	
Credit/Surcharge		$0.0033	($0.1939)	($0.3232)	($0.3755)	$0.0949	$0.3198	
Revised								
System Average		$0.9252	$0.9252	$0.9252	$0.9252	$0.9252	$0.9252	
Path		$0.9604	$1.1578	$1.0205	$1.3399	$0.8669	$0.6425	
Credit/Surcharge		($0.0352)	($0.2326)	($0.0952)	($0.4147)	$0.0584	$0.2828	
Variance- approved Surcharge/Credit vs. Revised Surcharge/C		($0.0385)	($0.0387)	$0.2279	($0.0392)	($0.0365)	($0.0370)	
Annual MDCQ		2,378,957	3,110,860	3,476,899	1,442,805	993,367	285,300	11,688,187
Marketer Reconciliation Adjustment		($91,566)	($120,445)	$792,492	($56,608)	($36,261)	($10,562)	$477,049
2010/11 & 2011/2012 Marketer Reconciliation								$374,462

Note: Tennessee rates for June - October 2011 are the settlement rates reflecting since there was a refund of the difference between the rates in effect at that time and the settlement rates.

DIRECT TESTIMONY

OF

STEPHEN A. MC CAULEY

September 4, 2012

Table of Contents

I. INTRODUCTION

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS**.

A. My name is Stephen A Mc Cauley. My business address is 100 E. Old Country Road, Hicksville, NY 11801**.**

Q. WHAT IS YOUR POSITION AND RESPONSIBILITIES?

A. I am Director of Origination and Price Volatility Management in the Energy Procurement organization. As Director, I am responsible for all financial hedging activity for the National Grid regulated natural gas and electric utilities. I am also responsible for structuring and optimizing the natural gas assets to help return the most value to the regulated entities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the United States Merchant Marine Academy in 1984 with a Bachelor of Science degree in Marine Engineering Systems.

Q. PLEASE DESCRIBE YOUR PROFESSION EXPERIENCE.

A. I joined National Grid in 1992 as an engineer for the gas peak-shaving plants and the gas-regulator and telemetering stations. In 1996, I joined the gas supply group as a trader responsible for purchasing the natural gas supply requirements for both the firm gas customers and the LILCO generation facilities. In 1999, my responsibilities were changed to managing the emissions-allowance portfolio and the financial-hedging activities of the regulated utilities. In 2002, I was promoted to my current position as Director.

Q. ARE YOU SPONSORING ANY ATTACHMENTS?

A. Yes. I am sponsoring the following schedules:

SAM-1	Revised Gas Procurement Incentive Plan (GPIP) for National Grid
SAM-1a	Redlined Gas Procurement Incentive Plan
SAM-2	GPIP July 2011 through June 2012 Results (excerpt pages 1-8)
SAM-3	NGPMP Annual Report, April 2011 through March 2012 (excerpt pages 1-12)

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the results of the Gas Procurement Incentive Plan ("GPIP") for the period July 1, 2011 through June 30, 2012. In addition, I also will address the results of the Natural Gas Portfolio Management Plan ("NGPMP") for the period April 1, 2011 through March 31, 2012.

II. <u>GAS PROCUREMENT INCENTIVE PLAN</u>

Q. PLEASE DESCRIBE THE INCENTIVE PORTION OF THE GAS PROCUREMENT INCENTIVE PLAN (GPIP)?

A. The GPIP encourages the Company to purchase supply in a way designed to stabilize prices and reduce the risk that commodity costs will escalate dramatically. An outline of the proposed GPIP with revisions is provided in Attachment SAM-1 and the relined version reflecting changes to the plan approved by the Commission in last year's GCR proceeding, Docket No. 4283.

The gas procurement portion of the GPIP is based on the Company's gas purchasing program under which the Company fixes the price of commodity purchases through purchases or financial hedges over a 24-month horizon. The minimum amount fixed or financially hedged is 60% of the expected purchases for April and October, and 70% for the remaining ten months of the year. The hedged volume is based on the five-year firm-sales forecast filed each year in the Gas Cost Recovery docket. These mandatory hedges are required to be made ratably over the period beginning 24 months prior to the start of each month and ending four months before the month begins. These mandatory hedges also form the benchmark for the incentive calculation. For each month, the average unit cost of the mandatory hedges is compared to the average unit cost of discretionary purchases to determine the savings or loss per dekatherm resulting from the discretionary purchases. This difference, multiplied by the discretionary volumes, determines the total savings or cost. To determine the incentive or penalty for the month, this total is multiplied by 10% with two exceptions. The first exception is for discretionary purchases made at least 8 months prior to the month of gas flow where the unit cost savings is greater than 50 cents per dekatherm, in which case the incentive applicable to those purchases is 20%. The second exception is that for any discretionary purchases made during the four months prior to the month of flow will only generate an incentive of 5%.

Q. WHAT IS THE GPIP GAS PROCUREMENT INCENTIVE FOR THE PAST YEAR?

A. Attachment SAM-2, which contains pages 1 through 6 of the Company's Semi-Annual GPIP Report, shows the results for the period July 1, 2011 through June 30, 2012 by month. As shown, the Company purchased discretionary supply of 3,725,000 Dth during the period resulting in a net calculated incentive of $355,884. The average cost of discretionary purchases was per Dth less than the mandatory hedges.

The calculation of the savings and incentive is shown for each month. For example, in July 2011 the average purchase cost per Dth for mandatory purchases was $5.4991 and discretionary purchases were made at an average cost of $4.6921, which equates to a savings of $0.81 per Dth on discretionary purchases of 163,000 Dth, resulting in a savings for the month of $131,526.

Q. WHAT IS THE GAS PROCUREMENT INCENTIVE THE COMPANY IS FILING?

A. The Company is proposing that it be granted the full incentive of $355,884 for the period July 2011 through June 2012.

Q. ARE THERE ANY RECOMMENDED CHANGES TO THE GPIP FOR THE PERIOD STARTING JULY 2012?

A. No. The Company is not recommending any changes at this time.

III. NATURAL GAS PORTFOLIO MANAGEMENT PLAN (“NGPMP”)

Q. BRIEFLY DESCRIBE THE NGPMP?

A. In Docket No. 4038, the Commission approved the NGPMP which implemented changes to the management of the Company’s Rhode Island gas portfolio. These changes were designed to provide various financial, regulatory, and risk management benefits over the previous asset management arrangements. The Company changed the management of the gas portfolio from an external third-party asset-management agreement to an internal portfolio management by the Company. The Company uses its transportation contracts, underground storage contracts, peaking supplies, and supply contracts first to purchase gas supplies to economically and reliably serve sales customers and then to make additional purchases and sales that generate revenue by extracting value from any assets that are not required to serve customers on any day. The mix of supply, transportation, and storage contracts creates flexibility and opportunities for optimization to create value for Rhode Island customers. This potential optimization value is subject to market variables: the fluctuation of gas pricing, the value of temporarily unused assets, the existence of excess transportation and storage capacity, and the opportunities to optimize delivered supplies as storage fill opportunities arise. These activities were previously executed by external third-party asset managers. The Company believes that the internal management of the portfolio is superior to the external portfolio management for two primary reasons. First, active asset management by the Company reduces the potential for performance failure by a third-party asset manager, which may impact supply reliability. Second, the NGPMP creates an appropriate incentive for the Company to maximize the savings to its customers at levels that would be comparable to or that would exceed those from a third-party asset manager.

Q. WHAT WERE THE RESULTS OF THE NPGMP FOR THE INCENTIVE YEAR APRIL 2011 THROUGH MARCH 2012?

A. As required by Order 19627 in Commission Docket No. 4038, the Company has filed comprehensive reports of its optimization activity each quarter and on June 1, 2012, it filed its annual report showing the results of the past year of the NGPMP, April 2011 through March 2012. Attachment SAM-3 contains pages 1 through 13 of that annual report which shows that the second year of the NGPMP produced total savings of $5,498,990.90. Under the provisions of the NGPMP, customers receive $4,599,192 of those savings.

Q. WHAT IS THE NGPMP INCENTIVE THE COMPANY IS FILING?

A. The Company's incentive, as specified in the NGPMP, is determined as 20% of the total savings in excess of $1,000,000. Accordingly, the Company is filing for approval of an NGPMP incentive of $899,798 for the April 2011 through March 2012 period.

Q. ARE THERE ANY RECOMMENDED CHANGES TO THE NGPMP FOR THE PERIOD STARTING APRIL 2013?

A. In Docket 4283 the Commission approved the continuation of the NGPMP through March 2014 and therefore no changes will take effect starting in April 2013. As required by Order 19627 Docket 4038, the Company and Division will review the results of the NGPMP after March 2013 in order to evaluate additional extensions and/or recommended changes to the Plan for inclusion in the Company's September 1, 2013 GCR filing.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Gas Procurement Incentive Plan for National Grid

Revised Effective July 1, 2011

I. Objective

To reduce the volatility of gas costs and to encourage National Grid (or "Company") to achieve a lower hedged gas commodity cost for its customers.

II. Structure of the Gas Procurement Incentive Plan

A. The original Plan became effective June 1, 2003 and was most recently revised in Docket No. 4283. It will be reviewed with each gas cost recovery ("GCR") filing. The cap on the amount of the incentive that may be earned by the Company was eliminated effective July 1, 2010 and approved by the Commission in Docket 4283. The Company will file the Plan results semi-annually on January 31st and July 31 of each year. Effective January 2011 the quarterly reports were eliminated and the material was consolidated into the semi-annual report. These reports shall include reporting for all Plan activity and results through the end of the month prior to the filing.

1. The Gas Procurement Incentive Plan revised effective December 1, 2008 applied to discretionary hedges that settled up to June 2010.
2. This revised Plan will be effective for hedges that settle starting in July 2010.

B. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. The hedging plan volume will be adjusted based on this revised forecast. Changes to the hedged volume execution plan will become effective in November of each year. The Company will not unwind or sell any purchases or hedged positions without notifying the Commission and Division. If a midyear revision is warranted the Company will file support for the revised purchase forecast with the Commission and Division.

III. <u>The Gas Procurement Incentive Program</u>

A. The Company will make purchases of natural gas, natural gas swaps or natural gas futures which lock or hedge the NYMEX Henry Hub portion of the variable cost. For any future gas supply month the Company will make three types of gas purchases:

1. Mandatory Purchases and/or Hedges

a. Are defined as mandatory monthly purchases of gas volumes or hedges made in approximately uniform monthly increments. (Mandatory purchases and/or hedges will vary as the forecast of purchases is updated periodically and in order to adjust for the rounding of the 10,000 Dth futures contract.)

b. Will equal 60% of forecasted normal weather gas purchase requirements for the April and October gas supply months and 70% of forecasted normal weather gas purchase requirements for the remaining ten months. Purchases and/or hedges will be based on the forecast of requirements in place when the purchases and/or hedges are made.

c. Will be purchased in approximately uniform monthly increments on a mandatory basis starting 24 months prior to the month of delivery and ending 4 months prior to the start of deliveries.

d. The first purchases and/or hedges made each month will be deemed the Company's mandatory hedge up to the amount of the Company's scheduled mandatory requirement for the month.

e. The Company will make the financial hedges in increments of one contract, 10,000 Dth. The Company will adjust the schedule of hedging to achieve the required mandatory level in accordance with paragraph II.B. Within the constraints of 10,000 Dth contract increments, the Company will seek to maximize the uniformity of monthly mandatory purchase/hedge volumes over the 20 month period specified in paragraph III.A.1.c.

f. The Company and the Division may agree to accelerate a portion of the mandatory hedges. They will notify the Commission of any such plan and provide 3 business days for the Commission to object. Accelerated hedges will neither earn an incentive nor be used in the calculation of mandatory benchmark.

2. Discretionary Purchases and/or Hedges

a. Are defined as the purchases and/or hedges established at least 6 business days prior to the start of the delivery month for delivery to the system or storage in excess of the mandatory hedging requirements in a month.

b. The cost or benefit of any financial purchase and/or hedge will be included in the calculation of the average unit price.

c. The total financial and physical hedged volume (planned mandatory plus accelerated plus discretionary), shall not exceed 95% of the forecasted normal weather requirements for a given supply month. Subsequent revisions to the forecast may impact the hedge percentage for existing deals.

3. Other Discretionary Purchases and/or Hedges Not Subject To Incentives

a. LNG

b. Supplies that lock in price but are not part of the program.

c. Hedges specifically put in place as part of the Natural Gas Procurement Management Program to lock in optimization savings for customers.

d. Purchases and/or hedges made less than 6 business days prior to the beginning of the month, during the month or under a contract which does not allow for the locking of the price.

e. Purchases and/or hedges made due to updated levels of forecasted migration of throughput volumes from transportation service to sales service.

B. Computation of Gas Procurement Incentives

Gas Procurement Incentives will be determined on the basis of comparisons of the volume-weighted average cost per dekatherm of discretionary purchases and/or hedges and the volume weighted average cost per dekatherm of mandatory gas purchases, excluding any accelerated hedges for each gas supply month. All comparisons will be based on the NYMEX portion of the variable cost per dekatherm of the purchased gas supply or the price of the NYMEX futures contract.

C. Any purchases and/or hedges made for a future gas supply month, excluding other discretionary purchases and/or hedges not subject to incentives as shown in III.A.3, that are in excess of the mandatory purchases and/or hedges requirement for the month, will be deemed discretionary purchases and/or hedges.

D. The timing of discretionary purchases and/or hedges is left solely to the discretion of the Company. However, beginning in November 2005 the Company will make sufficient discretionary purchases and/or hedges by November 1st of each year, such that a minimum of 80% of supply needed for December, January and February and 75% of supply needed for a normal November and March will be at a fixed or capped price. The fixed and capped supplies will include all forward purchases, financially based purchases and/or hedges, DOMAC FCS contract purchases fixed in price, LNG supplies and storage supplies.

E. After all purchases and/or hedges for forecasted gas requirements for a given gas supply month are completed, the volume-weighted average cost of mandatory purchases and/or hedges will be computed. That volume weighted average cost for mandatory purchases and/or hedges will then be compared against the actual cost of each discretionary purchase and/or hedge made for the same gas supply month.

1. For all discretionary purchases and/or hedges executed more than eight months prior to the start of the gas supply month, the Company will be provided a positive incentive equal to 10 percent

of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average cost of mandatory purchases and/or hedges for the same gas supply month. In the event that the cost of the discretionary purchases/hedges is at least 50 cents less than the cost of the mandatory purchases/hedges, the incentive will be 20 percent.

2. For all discretionary purchases and/or hedges executed within the last five to eight months prior to the start of the gas supply month, the Company will be provided as positive incentive equal to 10% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average cost of mandatory purchases for the same gas supply month.

3. For all discretionary purchases and/or hedges executed within the last four months prior to the start of the gas supply month, the Company will be provided as positive incentive equal to 5% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases for the same gas supply month.

4. For any and all discretionary purchases and/or hedges that are made at a cost which is greater than the volume-weighted average cost for mandatory purchases and/or hedges, made for the same gas supply month, regardless of when they occur prior to the start of the gas supply month, the Company will be assessed a penalty equal to 10% of the difference between the volume-weighted average cost for mandatory purchases and/or hedges and the cost of the each such discretionary purchase.

5. The net incentive/penalty for the Company for each gas supply month shall equal the sum of the incentives/penalties calculated for all individual discretionary purchases and/or hedges executed for the subject gas supply month.

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Gas Procurement Incentive Plan for National Grid

Revised Effective July 1, 2011

I. Objective

To reduce the volatility of gas costs and to encourage National Grid (or "Company") to achieve a lower hedged gas commodity cost for its customers.

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II. Structure of the Gas Procurement Incentive Plan

A. The original Plan became effective June 1, 2003 and was most recently revised in Docket No. 4283. It will be reviewed with each gas cost recovery ("GCR") filing. The cap on the amount of the incentive that may be earned by the Company was eliminated effective July 1, 2010 and approved by the Commission in Docket 4283. The Company will file the Plan results semi-annually on January 31st and July 31 of each year. Effective January 2011 the quarterly reports were eliminated and the material was consolidated into the semi-annual report. These reports shall include reporting for all Plan activity and results through the end of the month prior to the filing.

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1. The Gas Procurement Incentive Plan revised effective December 1, 2008 applied to discretionary hedges that settled up to June 2010.
2. This revised Plan will be effective for hedges that settle starting in July 2010.

B. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. The hedging plan volume will be adjusted based on this revised forecast. Changes to the hedged volume execution plan will become effective in November of each year. The Company will not unwind or sell any purchases or hedged positions without notifying the Commission and Division. If a midyear revision is warranted the Company will file support for the revised purchase forecast with the Commission and Division.

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III. The Gas Procurement Incentive Program

A. The Company will make purchases of natural gas, natural gas swaps or natural gas futures which lock or hedge the NYMEX Henry Hub portion of the variable cost. For any future gas supply month the Company will make three types of gas purchases:

1. Mandatory Purchases and/or Hedges

a. Are defined as mandatory monthly purchases of gas volumes or hedges made in approximately uniform monthly increments. (Mandatory purchases and/or hedges will vary as the forecast of purchases is updated periodically and in order to adjust for the rounding of the 10,000 Dth futures contract.)

b. Will equal 60% of forecasted normal weather gas purchase requirements for the April and October gas supply months and 70% of forecasted normal weather gas purchase requirements for the remaining ten months. Purchases and/or hedges will be based on the forecast of requirements in place when the purchases and/or hedges are made.

c. Will be purchased in approximately uniform monthly increments on a mandatory basis starting 24 months prior to the month of delivery and ending 4 months prior to the start of deliveries.

d. The first purchases and/or hedges made each month will be deemed the Company's mandatory hedge up to the amount of the Company's scheduled mandatory requirement for the month.

e. The Company will make the financial hedges in increments of one contract, 10,000 Dth. The Company will adjust the schedule of hedging to achieve the required mandatory level in accordance with paragraph II.B. Within the constraints of 10,000 Dth contract increments, the Company will seek to maximize the uniformity of monthly mandatory purchase/hedge volumes over the 20 month period specified in paragraph III.A.1.c.

f. The Company and the Division may agree to accelerate a portion of the mandatory hedges. They will notify the Commission of any such plan and provide 3 business days for the Commission to object. Accelerated hedges will neither earn an incentive nor be used in the calculation of mandatory benchmark.

2. Discretionary Purchases and/or Hedges

a. Are defined as the purchases and/or hedges established at least 6 business days prior to the start of the delivery month for delivery to the system or storage in excess of the mandatory hedging requirements in a month.

b. The cost or benefit of any financial purchase and/or hedge will be included in the calculation of the average unit price.

c. The total financial and physical hedged volume (planned mandatory plus accelerated plus discretionary), shall not exceed 95% of the forecasted normal weather requirements for a given supply month. Subsequent revisions to the forecast may impact the hedge percentage for existing deals.

3. Other Discretionary Purchases and/or Hedges Not Subject To Incentives

a. LNG

b. Supplies that lock in price but are not part of the program.

c. Hedges specifically put in place as part of the Natural Gas Procurement Management Program to lock in optimization savings for customers.

d. Purchases and/or hedges made less than 6 business days prior to the beginning of the month, during the month or under a contract which does not allow for the locking of the price.

e. Purchases and/or hedges made due to updated levels of forecasted migration of throughput volumes from transportation service to sales service.

B. Computation of Gas Procurement Incentives

Gas Procurement Incentives will be determined on the basis of comparisons of the volume-weighted average cost per dekatherm of discretionary purchases and/or hedges and the volume weighted average cost per dekatherm of mandatory gas purchases, excluding any accelerated hedges for each gas supply month. All comparisons will be based on the NYMEX portion of the variable cost per dekatherm of the purchased gas supply or the price of the NYMEX futures contract.

C. Any purchases and/or hedges made for a future gas supply month, excluding other discretionary purchases and/or hedges not subject to incentives as shown in III.A.3, that are in excess of the mandatory purchases and/or hedges requirement for the month, will be deemed discretionary purchases and/or hedges.

D. The timing of discretionary purchases and/or hedges is left solely to the discretion of the Company. However, beginning in November 2005 the Company will make sufficient discretionary purchases and/or hedges by November 1st of each year, such that a minimum of 80% of supply needed for December, January and February and 75% of supply needed for a normal November and March will be at a fixed or capped price. The fixed and capped supplies will include all forward purchases, financially based purchases and/or hedges, DOMAC FCS contract purchases fixed in price, LNG supplies and storage supplies.

E. After all purchases and/or hedges for forecasted gas requirements for a given gas supply month are completed, the volume-weighted average cost of mandatory purchases and/or hedges will be computed. That volume weighted average cost for mandatory purchases and/or hedges will then be compared against the actual cost of each discretionary purchase and/or hedge made for the same gas supply month.

1. For all discretionary purchases and/or hedges executed more than eight months prior to the start of the gas supply month, the Company will be provided a positive incentive equal to 10% of

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the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average cost of mandatory purchases and/or hedges for the same gas supply month. In the event that the cost of the discretionary purchases/hedges is at least 50 cents less than the cost of the mandatory purchases/hedges, the incentive will be 20%.

2. For all discretionary purchases and/or hedges executed within the last five to eight months prior to the start of the gas supply month, the Company will be provided as positive incentive equal to 10% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average cost of mandatory purchases for the same gas supply month.

3. For all discretionary purchases and/or hedges executed within the last four months prior to the start of the gas supply month, the Company will be provided as positive incentive equal to 5% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases for the same gas supply month.

4. For any and all discretionary purchases and/or hedges that are made at a cost which is greater than the volume-weighted average cost for mandatory purchases and/or hedges, made for the same gas supply month, regardless of when they occur prior to the start of the gas supply month, the Company will be assessed a penalty equal to 10% of the difference between the volume-weighted average cost for mandatory purchases and/or hedges and the cost of the each such discretionary purchase.

5. The net incentive/penalty for the Company for each gas supply month shall equal the sum of the incentives/penalties calculated for all individual discretionary purchases and/or hedges executed for the subject gas supply month.

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Thomas R. Teehan
Senior Counsel – Rhode Island

August 1, 2012

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Semi-annual Report on Gas Procurement Incentive Plan

Dear Ms. Massaro:

Pursuant to the provisions of the Gas Procurement Incentive Plan ("Plan") initially approved in Docket No. 3436, enclosed are ten (10) copies of National Grid's semi-annual report on the status of the penalties and incentives as of the end of June 2011.

A summary of incentives and penalties associated with the GPIP is shown on page 1 of the attachment. This summary shows the purchases made under the GPIP for the months of July 2011 to June 2014. Through June 30, 2012, the discretionary purchases have resulted in $2.6 million in savings compared to the benchmark mandatory prices. The associated Company incentive for this period is $0.4 million. For the July 2012 to June 2013 year, it shows a benefit to customers from discretionary purchases of $2.8 million and a $0.5 million calculated incentive. For the July 2013 to June 2014 measurement year, the benefit is $0.07 million and the incentive is $0.01 million.

Pages 2 and 3 reflect Plan provisions where, discretionary hedges can have an incentive of 10 percent if they were made five to eight months in advance of the supply period and 20 percent if they were made greater than 8 months in advance of the supply period and if the cost was at least $0.50 per dekatherm lower than the prices obtained for the mandatory purchasing amount. For all discretionary purchases and/or hedges executed within the last four months prior to the start of the gas supply period, the incentive equals 5 percent of the difference between the cost of each discretionary and mandatory purchase. These figures are shown on page 4.

Page 5 of the Report shows the mandatory, accelerated, and discretionary hedge volumes and the total volume hedged as a percentage of the original forecast. The last two columns on page 5 show the average NYMEX hedge price and the total weighted cost.

Page 6 of the Report shows the dollar amount of hedges broken out into mandatory, accelerated, and discretionary and the unit cost of each type of hedge under the program.

Finally, the individual trade data that had previously been provided in the GPIP quarterly report is shown beginning on page 7.

Thank you for your attention to this matter. If you have any questions, please do not hesitate to contact Stephen Mc Cauley at (516) 545-5403 or me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures
cc: Thomas Ahern, Division
Stephen Scialabba, Division
Bruce Oliver, Division
Leo Wold, Esq.

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Gas Procurement Incentive Program Worksheet - June 30, 2012
Incentive Calculation
National Grid - Rhode Island

TOTAL

	Mandatory NYMEX	Discretionary NYMEX	Difference	Discretionary Volumes (Dt)	Gain/ (Loss)	Aggregate * Incentive %	Company Incentive
Jul-11	$ 5.4991	$ 4.6921	$ 0.81	163,000	$ 131,526	10.00%	$ 13,153
Aug-11	$ 5.5336	$ 4.9009	$ 0.63	202,000	$ 127,805	10.00%	$ 12,780
Sep-11	$ 5.8136	$ 4.7907	$ 1.02	166,000	$ 169,808	15.23%	$ 25,854
Oct-11	$ 5.7167	$ 5.0080	$ 0.71	94,000	$ 66,613	15.61%	$ 10,399
Nov-11	$ 5.8693	$ 5.1914	$ 1.04	138,000	$ 143,297	13.06%	$ 18,711
Dec-11	$ 6.2298	$ 4.9743	$ 1.26	281,000	$ 352,798	20.00%	$ 70,560
Jan-12	$ 5.9471	$ 4.9555	$ 0.99	454,000	$ 450,199	14.58%	$ 65,628
Feb-12	$ 5.7335	$ 5.1623	$ 0.57	532,000	$ 303,879	10.00%	$ 30,388
Mar-12	$ 5.3124	$ 4.5439	$ 0.77	619,000	$ 475,697	14.66%	$ 69,726
Apr-12	$ 4.9247	$ 4.4734	$ 0.45	656,000	$ 296,020	10.00%	$ 29,602
May-12	$ 4.9125	$ 4.5848	$ 0.33	260,000	$ 85,227	10.00%	$ 8,523
Jun-12	$ 4.7821	$ 4.7470	$ 0.04	160,000	$ 5,611	10.00%	$ 561
Subtotal 11-12				3,725,000	$ 2,608,480		$ 355,884
Jul-12	$ 4.7743	$ 4.3258	$ 0.45	160,000	$ 71,762	10.00%	$ 7,176
Aug-12	$ 4.7660	$ 4.2702	$ 0.50	190,000	$ 94,194	10.00%	$ 9,419
Sep-12	$ 3.9253	$ 3.8920	$ 0.03	300,000	$ 9,998	10.00%	$ 1,000
Oct-12	$ 4.0987	$ 3.5824	$ 0.52	360,000	$ 185,850	10.00%	$ 18,585
Nov-12	$ 4.3596	$ 3.6486	$ 0.71	450,000	$ 319,935	20.00%	$ 63,987
Dec-12	$ 4.5346	$ 3.7011	$ 0.83	640,000	$ 533,473	20.00%	$ 106,695
Jan-13	$ 4.6610	$ 3.7997	$ 0.86	640,000	$ 551,223	20.00%	$ 110,245
Feb-13	$ 4.6205	$ 3.7433	$ 0.88	510,000	$ 447,361	20.00%	$ 89,472
Mar-13	$ 4.6032	$ 3.8992	$ 0.70	360,000	$ 253,441	20.00%	$ 50,688
Apr-13	$ 4.4080	$ 3.7857	$ 0.62	370,000	$ 230,235	20.00%	$ 46,047
May-13	$ 4.4764	$ 3.9379	$ 0.54	110,000	$ 59,235	20.00%	$ 11,847
Jun-13	$ 4.3208	$ 4.1738	$ 0.15	60,000	$ 8,823	10.00%	$ 882
Subtotal 12-13				4,150,000	$ 2,765,529		$ 516,043
Jul-13	$ 4.3698	$ 4.2151	$ 0.15	60,000	$ 9,285	10.00%	$ 928
Aug-13	$ 4.8688	$ 4.3678	$ 0.50	60,000	$ 30,055	20.00%	$ 6,011
Sep-13	$ 3.9868	$ 3.8837	$ 0.10	50,000	$ 5,156	10.00%	$ 516
Oct-13	$ 3.9734	$ 3.8657	$ 0.11	50,000	$ 5,389	10.00%	$ 539
Nov-13	$ 4.0198	$ 3.9543	$ 0.07	50,000	$ 3,275	10.00%	$ 327
Dec-13	$ 4.1456	$ 4.0155	$ 0.13	50,000	$ 6,508	10.00%	$ 651
Jan-14	$ 4.1446	$ 3.9951	$ 0.15	40,000	$ 5,980	10.00%	$ 598
Feb-14	$ 3.9667	$ 3.9584	$ 0.01	30,000	$ 247	10.00%	$ 25
Mar-14	$ 3.9170	$ 3.9287	$ (0.01)	20,000	$ (233)	-10.00%	$ (23)
Apr-14	$ 3.7925	$ 3.7187	$ 0.07	20,000	$ 1,477	10.00%	$ 148
May-14	$ 3.7200	$ 3.6700	$ 0.05	10,000	$ 500	10.00%	$ 50
Jun-14	$ 3.7000	$ -	$ -	-	$ -	0.00%	$ -
Subtotal 13-14				440,000	$ 67,639		$ 9,769
TOTAL				8,315,000	$ 5,441,649		$ 881,696

* Percentage Computed as the weighted average of the three levels of incentive as detailed below:

a) INCENTIVE MECHANISM — Deals executed after Dec 1 2008

a. i) 5% for trades executed within 4 months to the start of the supply month; 10% for trades executed within the 8 months to the start of the Supply Month.

a. ii) 20% for trades executed at least 8 months prior to the start of the Supply Month and Margin is higher than $.50, 10% if margin is lower than $0.50.

In both a & b explained above a 10% Penalty is applicable for months where discretionary price is higher than the mandatory hedged price.

Gas Procurement Incentive Program Worksheet - June 30, 2012
Incentive Calculation
National Grid - Rhode Island

nationalgrid

Deals executed within eight months of the Supply Month - 10% Incentive Level

	VOLUME (Dth)			PURCHASE (USD)			Average Price ($/Dth)			Margin	10% Incentive
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	($/Dth)	(USD)
Jul-11	370,000	480,000	90,000	$ 2,034,650	$ 3,084,500	$ 390,450	$ 5.4991	$ 6.4260	$ 4.3383	$ 1.1607	$ 10,446
Aug-11	308,000	470,000	110,000	$ 1,704,360	$ 3,109,050	$ 474,450	$ 5.5336	$ 6.6150	$ 4.3132	$ 1.2205	$ 13,425
Sep-11	136,000	470,000	50,000	$ 790,650	$ 3,062,050	$ 209,600	$ 5.8136	$ 6.5150	$ 4.1920	$ 1.6216	$ 8,108
Oct-11	356,000	590,000	20,000	$ 2,035,140	$ 3,986,800	$ 85,100	$ 5.7167	$ 6.7573	$ 4.2550	$ 1.4617	$ 2,923
Nov-11	609,000	1,510,000	-	$ 3,574,430	$ 9,795,450	$ -	$ 5.8693	$ 6.4871	$ -	$ -	$ -
Dec-11	691,000	1,700,000	-	$ 4,304,790	$ 11,367,600	$ -	$ 6.2298	$ 6.6868	$ -	$ -	$ -
Jan-12	838,000	1,670,000	200,000	$ 4,983,680	$ 11,361,150	$ 945,300	$ 5.9471	$ 6.8031	$ 4.7265	$ 1.2206	$ 24,412
Feb-12	720,000	1,500,000	140,000	$ 4,128,150	$ 9,728,000	$ 664,900	$ 5.7335	$ 6.4853	$ 4.7493	$ 0.9843	$ 13,780
Mar-12	780,000	1,670,000	180,000	$ 4,143,680	$ 9,787,250	$ 702,100	$ 5.3124	$ 5.8606	$ 3.9006	$ 1.4119	$ 25,413
Apr-12	789,000	970,000	200,000	$ 3,885,585	$ 5,431,650	$ 818,500	$ 4.9247	$ 5.5996	$ 4.0925	$ 0.8322	$ 16,644
May-12	595,000	740,000	-	$ 2,922,965	$ 4,133,550	$ -	$ 4.9125	$ 5.5859	$ -	$ -	$ -
Jun-12	500,000	540,000	-	$ 2,391,050	$ 2,972,800	$ -	$ 4.7821	$ 5.5052	$ -	$ -	$ -
Jul-12	370,000	420,000	-	$ 1,766,500	$ 2,207,900	$ -	$ 4.7743	$ 5.2569	$ -	$ -	$ -
Aug-12	310,000	400,000	-	$ 1,477,450	$ 2,071,900	$ -	$ 4.7660	$ 5.1798	$ -	$ -	$ -
Sep-12	510,000	300,000	-	$ 2,001,900	$ 1,501,500	$ -	$ 3.9253	$ 5.0050	$ -	$ -	$ -
Oct-12	230,000	540,000	10,000	$ 942,700	$ 2,664,900	$ 26,780	$ 4.0987	$ 4.9350	$ 2.6780	$ 1.4207	$ 1,421
Nov-12	870,000	950,000	-	$ 3,792,861	$ 4,987,250	$ -	$ 4.3596	$ 5.2497	$ -	$ -	$ -
Dec-12	1,190,000	1,110,000	-	$ 5,396,228	$ 5,951,000	$ -	$ 4.5346	$ 5.3613	$ -	$ -	$ -
Jan-13	1,250,000	1,190,000	-	$ 5,826,236	$ 6,515,050	$ -	$ 4.6610	$ 5.4748	$ -	$ -	$ -
Feb-13	1,050,000	1,040,000	-	$ 4,851,475	$ 5,443,600	$ -	$ 4.6205	$ 5.2342	$ -	$ -	$ -
Mar-13	930,000	1,170,000	-	$ 4,280,988	$ 6,229,900	$ -	$ 4.6032	$ 5.3247	$ -	$ -	$ -
Apr-13	590,000	880,000	-	$ 2,600,705	$ 4,579,900	$ -	$ 4.4080	$ 5.2044	$ -	$ -	$ -
May-13	430,000	640,000	-	$ 1,924,840	$ 3,294,000	$ -	$ 4.4764	$ 5.1469	$ -	$ -	$ -
Jun-13	340,000	520,000	-	$ 1,469,078	$ 2,632,100	$ -	$ 4.3208	$ 5.0617	$ -	$ -	$ -
Jul-13	220,000	410,000	-	$ 961,366	$ 2,071,100	$ -	$ 4.3698	$ 5.0515	$ -	$ -	$ -
Aug-13	80,000	370,000	-	$ 389,500	$ 1,824,900	$ -	$ 4.8688	$ 4.9322	$ -	$ -	$ -
Sep-13	290,000	290,000	-	$ 1,156,168	$ 1,409,450	$ -	$ 3.9868	$ 4.8602	$ -	$ -	$ -
Oct-13	200,000	340,000	-	$ 794,688	$ 1,580,650	$ -	$ 3.9734	$ 4.6490	$ -	$ -	$ -
Nov-13	430,000	860,000	-	$ 1,728,495	$ 3,930,650	$ -	$ 4.0198	$ 4.5705	$ -	$ -	$ -
Dec-13	480,000	1,120,000	-	$ 1,989,900	$ 5,062,925	$ -	$ 4.1456	$ 4.5205	$ -	$ -	$ -
Jan-14	480,000	1,240,000	-	$ 1,989,400	$ 5,240,500	$ -	$ 4.1446	$ 4.2262	$ -	$ -	$ -
Feb-14	360,000	1,070,000	-	$ 1,428,000	$ 4,402,660	$ -	$ 3.9667	$ 4.1146	$ -	$ -	$ -
Mar-14	300,000	1,120,000	-	$ 1,175,100	$ 4,425,150	$ -	$ 3.9170	$ 3.9510	$ -	$ -	$ -
Apr-14	160,000	760,000	-	$ 606,800	$ 2,774,950	$ -	$ 3.7925	$ 3.6513	$ -	$ -	$ -
May-14	90,000	560,000	-	$ 334,800	$ 2,111,900	$ -	$ 3.7200	$ 3.7713	$ -	$ -	$ -
Jun-14	50,000	440,000	-	$ 185,000	$ 1,626,900	$ -	$ 3.7000	$ 3.6975	$ -	$ -	$ -

nationalgrid

Gas Procurement Incentive Program Worksheet - June 30, 2012
Incentive Calculation
National Grid - Rhode Island

Deals executed more than eight months prior to the Supply Month - 20% Incentive Level

	VOLUME (Dth) Mandatory	VOLUME (Dth) Accelerated	VOLUME (Dth) Discretionary	PURCHASE (USD) Mandatory	PURCHASE (USD) Accelerated	PURCHASE (USD) Discretionary	Average Price ($/Dth) Mandatory	Average Price ($/Dth) Accelerated	Average Price ($/Dth) Discretionary	Margin ($/Dth)	20% Incentive (USD)
Jul-11	370,000	480,000	73,000	$ 2,034,650	$ 3,084,500	$ 374,370	$ 5.4991	$ 6.4260	$ 5.1284	$ 0.3707	$ 2,706
Aug-11	308,000	470,000	92,000	$ 1,704,360	$ 3,109,050	$ 515,540	$ 5.5336	$ 6.6150	$ 5.6037	$ (0.0701)	$ (645)
Sep-11	136,000	470,000	116,000	$ 790,650	$ 3,062,050	$ 585,650	$ 5.8136	$ 6.5150	$ 5.0487	$ 0.7649	$ 17,746
Oct-11	356,000	590,000	74,000	$ 2,035,140	$ 3,986,800	$ 385,655	$ 5.7167	$ 6.7573	$ 5.2116	$ 0.5051	$ 7,476
Nov-11	609,000	1,510,000	138,000	$ 3,574,430	$ 9,795,450	$ 716,415	$ 5.8693	$ 6.4871	$ 5.1914	$ 0.6779	$ 18,711
Dec-11	691,000	1,700,000	281,000	$ 4,304,790	$ 11,367,600	$ 1,397,775	$ 6.2298	$ 6.6868	$ 4.9743	$ 1.2555	$ 70,560
Jan-12	838,000	1,670,000	254,000	$ 4,983,680	$ 11,361,150	$ 1,304,490	$ 5.9471	$ 6.8031	$ 5.1358	$ 0.8113	$ 41,215
Feb-12	720,000	1,500,000	392,000	$ 4,128,150	$ 9,728,000	$ 2,081,465	$ 5.7335	$ 6.4853	$ 5.3099	$ 0.4237	$ 16,608
Mar-12	780,000	1,670,000	439,000	$ 4,143,680	$ 9,787,250	$ 2,110,585	$ 5.3124	$ 5.8606	$ 4.8077	$ 0.5047	$ 44,313
Apr-12	789,000	970,000	456,000	$ 3,885,585	$ 5,431,650	$ 2,116,080	$ 4.9247	$ 5.5996	$ 4.6405	$ 0.2842	$ 12,958
May-12	595,000	740,000	260,000	$ 2,922,965	$ 4,133,550	$ 1,192,035	$ 4.9125	$ 5.5859	$ 4.5848	$ 0.3278	$ 8,523
Jun-12	500,000	540,000	160,000	$ 2,391,050	$ 2,972,800	$ 759,525	$ 4.7821	$ 5.5052	$ 4.7470	$ 0.0351	$ 561
Jul-12	370,000	420,000	160,000	$ 1,766,500	$ 2,207,900	$ 692,130	$ 4.7743	$ 5.2569	$ 4.3258	$ 0.4485	$ 7,176
Aug-12	310,000	400,000	190,000	$ 1,477,450	$ 2,071,900	$ 811,340	$ 4.7660	$ 5.1798	$ 4.2702	$ 0.4958	$ 9,419
Sep-12	510,000	300,000	300,000	$ 2,001,900	$ 1,501,500	$ 1,167,590	$ 3.9253	$ 5.0050	$ 3.8920	$ 0.0333	$ 1,000
Oct-12	230,000	540,000	350,000	$ 942,700	$ 2,664,900	$ 1,262,900	$ 4.0987	$ 4.9350	$ 3.6083	$ 0.4904	$ 17,164
Nov-12	870,000	950,000	450,000	$ 3,792,861	$ 4,987,250	$ 1,641,890	$ 4.3596	$ 5.2497	$ 3.6486	$ 0.7110	$ 63,987
Dec-12	1,190,000	1,110,000	640,000	$ 5,396,228	$ 5,951,000	$ 2,368,700	$ 4.5346	$ 5.3613	$ 3.7011	$ 0.8336	$ 106,695
Jan-13	1,250,000	1,190,000	640,000	$ 5,826,236	$ 6,515,050	$ 2,431,810	$ 4.6610	$ 5.4748	$ 3.7997	$ 0.8613	$ 110,245
Feb-13	1,050,000	1,040,000	510,000	$ 4,851,475	$ 5,443,600	$ 1,909,070	$ 4.6205	$ 5.2342	$ 3.7433	$ 0.8772	$ 89,472
Mar-13	930,000	1,170,000	360,000	$ 4,280,988	$ 6,229,900	$ 1,403,716	$ 4.6032	$ 5.3247	$ 3.8992	$ 0.7040	$ 50,688
Apr-13	590,000	880,000	370,000	$ 2,600,705	$ 4,579,900	$ 1,400,716	$ 4.4080	$ 5.2044	$ 3.7857	$ 0.6223	$ 46,047
May-13	430,000	640,000	110,000	$ 1,924,840	$ 3,294,000	$ 433,166	$ 4.4764	$ 5.1469	$ 3.9379	$ 0.5385	$ 11,847
Jun-13	340,000	520,000	60,000	$ 1,469,078	$ 2,632,100	$ 250,426	$ 4.3208	$ 5.0617	$ 4.1738	$ 0.1471	$ 882
Jul-13	220,000	410,000	60,000	$ 961,366	$ 2,071,100	$ 252,906	$ 4.3698	$ 5.0515	$ 4.2151	$ 0.1547	$ 928
Aug-13	80,000	370,000	60,000	$ 389,500	$ 1,824,900	$ 262,070	$ 4.8688	$ 4.9322	$ 4.3678	$ 0.5009	$ 6,011
Sep-13	290,000	290,000	50,000	$ 1,156,168	$ 1,409,450	$ 194,183	$ 3.9868	$ 4.8602	$ 3.8837	$ 0.1031	$ 516
Oct-13	200,000	340,000	50,000	$ 794,688	$ 1,580,650	$ 193,283	$ 3.9734	$ 4.6490	$ 3.8657	$ 0.1078	$ 539
Nov-13	430,000	860,000	50,000	$ 1,728,495	$ 3,930,650	$ 197,713	$ 4.0198	$ 4.5705	$ 3.9543	$ 0.0655	$ 327
Dec-13	480,000	1,120,000	50,000	$ 1,989,900	$ 5,062,925	$ 200,773	$ 4.1456	$ 4.5205	$ 4.0155	$ 0.1302	$ 651
Jan-14	480,000	1,240,000	40,000	$ 1,989,400	$ 5,240,500	$ 159,803	$ 4.1446	$ 4.2262	$ 3.9951	$ 0.1495	$ 598
Feb-14	360,000	1,070,000	30,000	$ 1,428,000	$ 4,402,660	$ 118,753	$ 3.9667	$ 4.1146	$ 3.9584	$ 0.0082	$ 25
Mar-14	300,000	1,120,000	20,000	$ 1,175,100	$ 4,425,150	$ 78,573	$ 3.9170	$ 3.9510	$ 3.9287	$ (0.0117)	$ (23)
Apr-14	160,000	760,000	20,000	$ 606,800	$ 2,774,950	$ 74,373	$ 3.7925	$ 3.6513	$ 3.7187	$ 0.0739	$ 148
May-14	90,000	560,000	10,000	$ 334,800	$ 2,111,900	$ 36,700	$ 3.7200	$ 3.7713	$ 3.6700	$ 0.0500	$ 50
Jun-14	50,000	440,000	-	$ 185,000	$ 1,626,900	$ -	$ 3.7000	$ 3.6975	$ -	$ -	$ -

Gas Procurement Incentive Program Worksheet - June 30, 2012
Incentive Calculation
National Grid - Rhode Island

nationalgrid

Deals executed within four months of the Supply Month - 5% Incentive Level

	VOLUME (Dth)			PURCHASE (USD)			Average Price ($/Dth)			Margin ($/Dth)	5% Incentive (USD)
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary		
Jul-11	370,000	480,000	-	$ 2,034,650	$ 3,084,500	$ -	$ 5.4991	$ 6.4260	$ -	$ -	$ -
Aug-11	308,000	470,000	-	$ 1,704,360	$ 3,109,050	$ -	$ 5.5336	$ 6.6150	$ -	$ -	$ -
Sep-11	136,000	470,000	-	$ 790,650	$ 3,062,050	$ -	$ 5.8136	$ 6.5150	$ -	$ -	$ -
Oct-11	356,000	590,000	-	$ 2,035,140	$ 3,986,800	$ -	$ 5.7167	$ 6.7573	$ -	$ -	$ -
Nov-11	609,000	1,510,000	-	$ 3,574,430	$ 9,795,450	$ -	$ 5.8693	$ 6.4871	$ -	$ -	$ -
Dec-11	691,000	1,700,000	-	$ 4,304,790	$ 11,367,600	$ -	$ 6.2298	$ 6.6868	$ -	$ -	$ -
Jan-12	838,000	1,670,000	-	$ 4,983,680	$ 11,361,150	$ -	$ 5.9471	$ 6.8031	$ -	$ -	$ -
Feb-12	720,000	1,500,000	-	$ 4,128,150	$ 9,728,000	$ -	$ 5.7335	$ 6.4853	$ -	$ -	$ -
Mar-12	780,000	1,670,000	-	$ 4,143,680	$ 9,787,250	$ -	$ 5.3124	$ 5.8606	$ -	$ -	$ -
Apr-12	789,000	970,000	-	$ 3,885,585	$ 5,431,650	$ -	$ 4.9247	$ 5.5996	$ -	$ -	$ -
May-12	595,000	740,000	-	$ 2,922,965	$ 4,133,550	$ -	$ 4.9125	$ 5.5859	$ -	$ -	$ -
Jun-12	500,000	540,000	-	$ 2,391,050	$ 2,972,800	$ -	$ 4.7821	$ 5.5052	$ -	$ -	$ -
Jul-12	370,000	420,000	-	$ 1,766,500	$ 2,207,900	$ -	$ 4.7743	$ 5.2569	$ -	$ -	$ -
Aug-12	310,000	400,000	-	$ 1,477,450	$ 2,071,900	$ -	$ 4.7660	$ 5.1798	$ -	$ -	$ -
Sep-12	510,000	300,000	-	$ 2,001,900	$ 1,501,500	$ -	$ 3.9253	$ 5.0050	$ -	$ -	$ -
Oct-12	230,000	540,000	-	$ 942,700	$ 2,664,900	$ -	$ 4.0987	$ 4.9350	$ -	$ -	$ -
Nov-12	870,000	950,000	-	$ 3,792,861	$ 4,987,250	$ -	$ 4.3596	$ 5.2497	$ -	$ -	$ -
Dec-12	1,190,000	1,110,000	-	$ 5,396,228	$ 5,951,000	$ -	$ 4.5346	$ 5.3613	$ -	$ -	$ -
Jan-13	1,250,000	1,190,000	-	$ 5,826,236	$ 6,515,050	$ -	$ 4.6610	$ 5.4748	$ -	$ -	$ -
Feb-13	1,050,000	1,040,000	-	$ 4,851,475	$ 5,443,600	$ -	$ 4.6205	$ 5.2342	$ -	$ -	$ -
Mar-13	930,000	1,170,000	-	$ 4,280,988	$ 6,229,900	$ -	$ 4.6032	$ 5.3247	$ -	$ -	$ -
Apr-13	590,000	880,000	-	$ 2,600,705	$ 4,579,900	$ -	$ 4.4080	$ 5.2044	$ -	$ -	$ -
May-13	430,000	640,000	-	$ 1,924,840	$ 3,294,000	$ -	$ 4.4764	$ 5.1469	$ -	$ -	$ -
Jun-13	340,000	520,000	-	$ 1,469,078	$ 2,632,100	$ -	$ 4.3208	$ 5.0617	$ -	$ -	$ -
Jul-13	220,000	410,000	-	$ 961,366	$ 2,071,100	$ -	$ 4.3698	$ 5.0515	$ -	$ -	$ -
Aug-13	80,000	370,000	-	$ 389,500	$ 1,824,900	$ -	$ 4.8688	$ 4.9322	$ -	$ -	$ -
Sep-13	290,000	290,000	-	$ 1,156,168	$ 1,409,450	$ -	$ 3.9868	$ 4.8602	$ -	$ -	$ -
Oct-13	200,000	340,000	-	$ 794,688	$ 1,580,650	$ -	$ 3.9734	$ 4.6490	$ -	$ -	$ -
Nov-13	430,000	860,000	-	$ 1,728,495	$ 3,930,650	$ -	$ 4.0198	$ 4.5705	$ -	$ -	$ -
Dec-13	480,000	1,120,000	-	$ 1,989,900	$ 5,062,925	$ -	$ 4.1456	$ 4.5205	$ -	$ -	$ -
Jan-14	480,000	1,240,000	-	$ 1,989,400	$ 5,240,500	$ -	$ 4.1446	$ 4.2262	$ -	$ -	$ -
Feb-14	360,000	1,070,000	-	$ 1,428,000	$ 4,402,660	$ -	$ 3.9667	$ 4.1146	$ -	$ -	$ -
Mar-14	300,000	1,120,000	-	$ 1,175,100	$ 4,425,150	$ -	$ 3.9170	$ 3.9510	$ -	$ -	$ -
Apr-14	160,000	760,000	-	$ 606,800	$ 2,774,950	$ -	$ 3.7925	$ 3.6513	$ -	$ -	$ -
May-14	90,000	560,000	-	$ 334,800	$ 2,111,900	$ -	$ 3.7200	$ 3.7713	$ -	$ -	$ -
Jun-14	50,000	440,000	-	$ 185,000	$ 1,626,900	$ -	$ 3.7000	$ 3.6975	$ -	$ -	$ -
Dec-14	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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NEC Gas Cost Volatility Hedging Summary

	Volume *	HEDGED VOLUME (Dth)			Monthly	Percentage	Average	
	Forecast (Dth)	Mandatory	Accelerated	Discretionary	"Locked"	"Locked"	Hedge Price	**Total Cost**
07/01/2011	1,213,899	370,000	480,000	163,000	1,013,000	83%	$ 5.8085	$ 5,883,970
08/01/2011	1,104,835	308,000	470,000	202,000	980,000	89%	$ 5.9218	$ 5,803,400
09/01/2011	878,854	136,000	470,000	166,000	772,000	88%	$ 6.0207	$ 4,647,950
10/01/2011	1,193,508	356,000	590,000	94,000	1,040,000	87%	$ 6.2430	$ 6,492,695
11/01/2011	2,455,700	609,000	1,510,000	138,000	2,257,000	88%	$ 6.2412	$ 14,086,295
12/01/2011	3,151,800	691,000	1,700,000	281,000	2,672,000	80%	$ 6.3885	$ 17,070,165
01/01/2012	3,437,900	838,000	1,670,000	454,000	2,962,000	86%	$ 6.2777	$ 18,594,620
02/01/2012	3,125,600	720,000	1,500,000	532,000	2,752,000	88%	$ 6.0329	$ 16,602,515
03/01/2012	3,103,900	780,000	1,670,000	619,000	3,069,000	99%	$ 5.4557	$ 16,743,615
04/01/2012	2,596,800	789,000	970,000	656,000	2,415,000	93%	$ 5.0732	$ 12,251,815
05/01/2012	1,681,300	595,000	740,000	260,000	1,595,000	95%	$ 5.1715	$ 8,248,550
06/01/2012	1,316,800	500,000	540,000	160,000	1,200,000	91%	$ 5.1028	$ 6,123,375
07/01/2012	1,035,100	370,000	420,000	160,000	950,000	92%	$ 4.9121	$ 4,666,530
08/01/2012	624,600	310,000	400,000	190,000	900,000	144%	$ 4.8452	$ 4,360,690
09/01/2012	1,104,500	510,000	300,000	300,000	1,110,000	100%	$ 4.2081	$ 4,670,990
10/01/2012	1,251,200	230,000	540,000	360,000	1,130,000	90%	$ 4.3339	$ 4,897,280
11/01/2012	2,489,600	870,000	950,000	450,000	2,270,000	91%	$ 4.5912	$ 10,422,001
12/01/2012	3,204,700	1,190,000	1,110,000	640,000	2,940,000	92%	$ 4.6653	$ 13,715,928
01/01/2013	3,506,300	1,250,000	1,190,000	640,000	3,080,000	88%	$ 4.7965	$ 14,773,096
02/01/2013	3,056,700	1,050,000	1,040,000	510,000	2,600,000	85%	$ 4.6939	$ 12,204,145
03/01/2013	3,105,800	930,000	1,170,000	360,000	2,460,000	79%	$ 4.8433	$ 11,914,604
04/01/2013	2,535,400	590,000	880,000	370,000	1,840,000	73%	$ 4.6638	$ 8,581,321
05/01/2013	1,621,700	430,000	640,000	110,000	1,180,000	73%	$ 4.7898	$ 5,652,006
06/01/2013	1,273,300	340,000	520,000	60,000	920,000	72%	$ 4.7300	$ 4,351,604
07/01/2013	964,700	220,000	410,000	60,000	690,000	72%	$ 4.7614	$ 3,285,372
08/01/2013	555,100	80,000	370,000	60,000	510,000	92%	$ 4.8558	$ 2,476,470
09/01/2013	1,068,800	290,000	290,000	50,000	630,000	59%	$ 4.3806	$ 2,759,801
10/01/2013	1,219,500	200,000	340,000	50,000	590,000	48%	$ 4.3536	$ 2,568,621
11/01/2013	2,472,600	430,000	860,000	50,000	1,340,000	54%	$ 4.3708	$ 5,856,858
12/01/2013	3,205,200	480,000	1,120,000	50,000	1,650,000	51%	$ 4.3961	$ 7,253,598
01/01/2014	3,508,900	480,000	1,240,000	40,000	1,760,000	50%	$ 4.1987	$ 7,389,703
02/01/2014	3,058,400	360,000	1,070,000	30,000	1,460,000	48%	$ 4.0749	$ 5,949,413
03/01/2014	3,130,700	300,000	1,120,000	20,000	1,440,000	46%	$ 3.9436	$ 5,678,823
04/01/2014	2,546,000	160,000	760,000	20,000	940,000	37%	$ 3.6767	$ 3,456,123
05/01/2014	1,611,900	90,000	560,000	10,000	660,000	41%	$ 3.7627	$ 2,483,400
06/01/2014	1,243,200	50,000	440,000	-	490,000	39%	$ 3.6978	$ 1,811,900

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NEC Gas Cost Volatility Hedging Summary

	PURCHASE (USD)			Average Price ($/Dth)		
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary
07/01/2011	$ 2,034,650	$ 3,084,500	$ 764,820	$ 5.4991	$ 6.4260	$ 4.6921
08/01/2011	$ 1,704,360	$ 3,109,050	$ 989,990	$ 5.5336	$ 6.6150	$ 4.9009
09/01/2011	$ 790,650	$ 3,062,050	$ 795,250	$ 5.8136	$ 6.5150	$ 4.7907
10/01/2011	$ 2,035,140	$ 3,986,800	$ 470,755	$ 5.7167	$ 6.7573	$ 5.0080
11/01/2011	$ 3,574,430	$ 9,795,450	$ 716,415	$ 5.8693	$ 6.4871	$ 5.1914
12/01/2011	$ 4,304,790	$ 11,367,600	$ 1,397,775	$ 6.2298	$ 6.6868	$ 4.9743
01/01/2012	$ 4,983,680	$ 11,361,150	$ 2,249,790	$ 5.9471	$ 6.8031	$ 4.9555
02/01/2012	$ 4,128,150	$ 9,728,000	$ 2,746,365	$ 5.7335	$ 6.4853	$ 5.1623
03/01/2012	$ 4,143,680	$ 9,787,250	$ 2,812,685	$ 5.3124	$ 5.8606	$ 4.5439
04/01/2012	$ 3,885,585	$ 5,431,650	$ 2,934,580	$ 4.9247	$ 5.5996	$ 4.4734
05/01/2012	$ 2,922,965	$ 4,133,550	$ 1,192,035	$ 4.9125	$ 5.5859	$ 4.5848
06/01/2012	$ 2,391,050	$ 2,972,800	$ 759,525	$ 4.7821	$ 5.5052	$ 4.7470
07/01/2012	$ 1,766,500	$ 2,207,900	$ 692,130	$ 4.7743	$ 5.2569	$ 4.3258
08/01/2012	$ 1,477,450	$ 2,071,900	$ 811,340	$ 4.7660	$ 5.1798	$ 4.2702
09/01/2012	$ 2,001,900	$ 1,501,500	$ 1,167,590	$ 3.9253	$ 5.0050	$ 3.8920
10/01/2012	$ 942,700	$ 2,664,900	$ 1,289,680	$ 4.0987	$ 4.9350	$ 3.5824
11/01/2012	$ 3,792,861	$ 4,987,250	$ 1,641,890	$ 4.3596	$ 5.2497	$ 3.6486
12/01/2012	$ 5,396,228	$ 5,951,000	$ 2,368,700	$ 4.5346	$ 5.3613	$ 3.7011
01/01/2013	$ 5,826,236	$ 6,515,050	$ 2,431,810	$ 4.6610	$ 5.4748	$ 3.7997
02/01/2013	$ 4,851,475	$ 5,443,600	$ 1,909,070	$ 4.6205	$ 5.2342	$ 3.7433
03/01/2013	$ 4,280,988	$ 6,229,900	$ 1,403,716	$ 4.6032	$ 5.3247	$ 3.8992
04/01/2013	$ 2,600,705	$ 4,579,900	$ 1,400,716	$ 4.4080	$ 5.2044	$ 3.7857
05/01/2013	$ 1,924,840	$ 3,294,000	$ 433,166	$ 4.4764	$ 5.1469	$ 3.9379
06/01/2013	$ 1,469,078	$ 2,632,100	$ 250,426	$ 4.3208	$ 5.0617	$ 4.1738
07/01/2013	$ 961,366	$ 2,071,100	$ 252,906	$ 4.3698	$ 5.0515	$ 4.2151
08/01/2013	$ 389,500	$ 1,824,900	$ 262,070	$ 4.8688	$ 4.9322	$ 4.3678
09/01/2013	$ 1,156,168	$ 1,409,450	$ 194,183	$ 3.9868	$ 4.8602	$ 3.8837
10/01/2013	$ 794,688	$ 1,580,650	$ 193,283	$ 3.9734	$ 4.6490	$ 3.8657
11/01/2013	$ 1,728,495	$ 3,930,650	$ 197,713	$ 4.0198	$ 4.5705	$ 3.9543
12/01/2013	$ 1,989,900	$ 5,062,925	$ 200,773	$ 4.1456	$ 4.5205	$ 4.0155
01/01/2014	$ 1,989,400	$ 5,240,500	$ 159,803	$ 4.1446	$ 4.2262	$ 3.9951
02/01/2014	$ 1,428,000	$ 4,402,660	$ 118,753	$ 3.9667	$ 4.1146	$ 3.9584
03/01/2014	$ 1,175,100	$ 4,425,150	$ 78,573	$ 3.9170	$ 3.9510	$ 3.9287
04/01/2014	$ 606,800	$ 2,774,950	$ 74,373	$ 3.7925	$ 3.6513	$ 3.7187
05/01/2014	$ 334,800	$ 2,111,900	$ 36,700	$ 3.7200	$ 3.7713	$ 3.6700
06/01/2014	$ 185,000	$ 1,626,900	$ -	$ 3.7000	$ 3.6975	$ -

nationalgrid

Thomas R. Teehan
Senior Counsel

June 1, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4038 – National Grid Natural Gas Portfolio Management Plan
Annual Report – April 1, 2011 to March 31, 2012

Dear Ms. Massaro:

On behalf of National Grid[1] enclosed please find ten (10) copies of the Company's Annual Report of activity relating to the Natural Gas Portfolio Management Plan ("NGPMP"). This filing is also accompanied by a Motion for Protective Treatment in accordance with Rule 1.2(g) of the Commission's Rules of Practice and Procedure and R.I.G.L. §38-2-2(4)(B). The Company seeks protection from public disclosure of the identities of certain companies in order to protect their pricing information for delivered volumes that are identified in the report. Additionally, the Company seeks protected treatment for account numbers to the extent that they appear on the attachments to this filing. Consequently and pursuant to Commission rules, the Company has provided the Commission with one copy of the confidential materials for its review, and has otherwise included redacted copies of the plan.

In this docket, the Commission approved the NGPMP, which implemented changes in the management of the Company's Rhode Island gas portfolio. These changes were designed to provide various financial, regulatory and risk management benefits over the asset management arrangement which it replaced. One of those benefits was to encourage the Company to minimize gas costs to customers by combining a least-cost dispatch with an asset optimization program designed to obtain the maximum value from the Rhode Island gas supply portfolio resources. As part of the NGPMP, the Company is required to file quarterly and annual reports in order to provide transparency in measuring the Company's performance.

This annual report covers the measurement year April 1, 2011 through March 31, 2012.

The enclosed report provides a Monthly Summary which calculates the savings achieved based on supporting data contained in Attachments 1 through 9. The Monthly Report indicates that the preliminary estimate of savings for the period April 1, 2011 to March 31, 2012 of the

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

optimization program is $5,498,990.90. The $1 million guarantee has been achieved with excess earnings of $4,498,990.90. The incentive to the Company is $899,798.18 at this time.

Also enclosed as part of this filing is a discussion of the Monthly Summary Report by section that describes the entries in the Monthly Summary and traces the entries in that report to the sources from which they are derived.

Thank you for your attention to this filing. Please feel free to contact me if you have any questions at (401) 784-7667 or Stephen Mc Cauley at (516) 545-5403.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4038 Service List
Leo Wold, Esq.
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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Natural Gas Portfolio Management Plan
Docket No. 4038

NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

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

I. BACKGROUND

On June 1, 2012, National Grid filed with the Commission its Plan Results for April 1, 2011 to March 31, 2012 of activity undertaken in pursuing the Natural Gas Portfolio Management Plan that was approved by the Commission in Order No. 19627. This filing includes information relative to the identity of companies that discloses the names of the suppliers and the paid for the supplies purchased. These references occur in Attachment 2 ("Flowing Transaction Deal"), Attachment 4 ("Storage Injection

Transactions"), Attachment 7 ("Realized Financial Transactions"), and Attachment 8 ("Narragansett Mark to Market"). National Grid is seeking protective treatment with respect to the identities of those companies in order to protect the pricing information, which is competitively sensitive information.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §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.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

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

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

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; <u>or</u> (2) to cause

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

substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I.2001).

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

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under that balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

II. BASIS FOR CONFIDENTIALITY

The Company has redacted the names of the companies from which purchases were made in order to protect the pricing information for those companies. Were this information revealed, those companies could be harmed in future negotiations with other parties. Public dissemination of this type of information could disincline these and other companies to deal with National Grid or to provide National Grid with their lowest prices. Thus, the absence of confidential treatment would negatively influence National Grid's ability to negotiate with these and other similar companies and to receive least cost pricing

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to those previously identified portions of its Natural Gas Portfolio Procurement Plan Results for April 1, 2011 to March 31, 2012.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorney,

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Dated: June 1, 2012

National Grid
Natural Gas Portfolio Management Plan Report
Annual Report
Plan Results for April 1, 2011 to March 31, 2012

Introduction

In Docket 4038 the Commission approved a new approach to the management of the gas supply portfolio called the Natural Gas Portfolio Management Plan (NGPMP). One of the conditions included in that filing was a requirement that the Company file reports on the results of the Plan each quarter and annually and that the filings provide sufficient detail and transparency for the Commission and Division to determine the reasonableness and appropriateness of the costs associated with asset management transactions.

The Commission's order in this docket requires the Company to provide in the Annual Report the information suggested by Mr. Oliver in his testimony. In addition to the detailed information on each optimization transaction included with each quarterly report and also attached to this report, Mr. Oliver requested that annual reports contain information on the assignment of the Service Company costs associated with asset management activities allocated to the Narragansett Electric Company. Essentially, 8.21% of the full cost of the energy transactions team is allocated to the Narragansett Electric Company's Gas Division (NEC-Gas) based on a three point allocation methodology that is updated each year. The 8.21% allocation is derived based on NEC Gas' share of revenue, payroll and assets as compared to the total for all National Grid USA gas utilities with each component given an equal weight. The Energy Transaction team FTE count did not change from last years report.

The goal of the NGPMP is to minimize gas costs to customers by encouraging the Company to obtain as much value as possible from the Rhode Island gas supply portfolio assets. In order to measure the impact of the Company's efforts to optimize the value of the portfolio, the NGPMP establishes two benchmarks that exactly parallel the approach used in its past contracting for asset management services.

The first benchmark is built on the concept of least cost dispatch and focuses on the optimization of flowing supply. It provides that as the starting point for the management of flowing supplies, the Company will set up its dispatch of supply resources for each month and each day so that it utilizes the lowest cost flowing supplies available from its existing supply portfolio in the same fashion it would have if it used an asset manager (Attachment 6).

The second benchmark is used to measure the effectiveness of the Company's efforts to minimize the cost of supply injected into storage and is also drawn directly from the asset management contracting approach. This benchmark has as its starting point the concept that storage will be filled based on uniform monthly injections over the full seven months of the injection season. To the extent the Company can reduce the cost of supplies injected into storage from that injection schedule it provides savings to customers. In order to be certain customers will benefit from the injection optimization transactions in spite of significant movements up or down in natural gas prices, the Company puts hedge positions in place to guarantee their effectiveness. These hedge positions cover price changes within the injection season and thus are short term in nature and also completely unrelated to the hedge positions utilized in the execution of the Gas Purchase Incentive Program.

Monthly Summary Report

The report consists of a series of attachments that begins with the Monthly Summary Report (Attachment 1) which provides an overview of the results followed by additional attachments that provide detailed support for the information in the Monthly Summary Report. The Monthly Summary Report is divided into two sections. Section 1 shows the results from the Company's efforts to optimize flowing supply while Section 2 shows the results from optimizing the purchase of gas injected into storage. Section 2 is, itself, divided into 3 parts with 2a showing the injection cost and 2b and 2c showing the hedging results broken down into those that have been realized and those that will occur in the future and are, as yet, unrealized.

Section 1 Flowing Supply/Storage Withdrawals

This Section shows the calculation of the savings to customers generated by the Company's optimization activities as it purchases supplies for delivery to the city gate. The calculation starts with the total actual cost of all flowing supplies for each month. That cost is subtracted from the sum of those purchases made to support sales to third parties as part of optimization transactions and the cost of supply for customers calculated using the least cost dispatch for the monthly and daily supplies delivered to the RI gas system. This difference is the savings generated by the optimization transactions executed during each month as flowing supplies were purchased and sales were made to third parties to generate revenues.

The costs for each supply purchase are the actual delivered costs including both the supply acquisition cost and any pipeline related charges for the volumes purchased during the month. The purchases included in the actual delivered cost are both the supplies needed to support third party sales and the gas supplies delivered to the citygate for the firm sales customers. As part of the optimization process, the Company purchases supplies to reduce overall costs and it is common for specific supply purchases to be used to meet a different need than that for which they were initially purchased. For instance volumes that were purchased to meet a third party sale may have been injected into storage if that resulted in a lower overall cost for all supply purchases. When the schedulers transport the purchase volumes to meet the various demands, such as storage injections, baseload, swing or sales, they look to move the volumes most efficiently. The Actual Flowing Cost also includes any storage withdrawals delivered to the firm customers at the delivered weighted average cost of supply (WACOG) based on the benchmark dispatch.

The actual flowing supply costs are listed by transaction on the Flowing Transaction Detail Report (Attachment 2). Third Party sales are the aggregate monthly sales volume and revenue associated with sales off system. The revenue for each deal is also listed in the Flowing Transaction Deal Report.

The Flowing Transaction Deal (FTD) Report shows for each month all gas purchases and storage withdrawals. In the January section of the report the total 4,470,341 dekatherms and $15,870,067.75 of purchases are shown as the sub-total for the month and can also be found in the Monthly Summary Report under the Actual Flowing Cost for Jan-12. The report shows city-gate purchases, those purchases entered into as part of optimization transactions and any storage withdrawals. It ties directly to the Company's booked gas cost payable amount. The second part of the FTD Report for January shows the revenue from off-system sales which is also shown on the Monthly Summary Report under the 3rd Party Sales column.

The Customer Cost, or dispatch cost, is calculated as the product of the price and volume received each day by the firm sales customers based on the least cost dispatch structure. The cost of the supplies for customers for each day is shown in the attached Customer Transaction Summaries (Attachments 3) for the months of April 2011 through March 2012. For example, the volume and cost shown in the Customer Cost section of Attachment 1 for April 2011 are from Attachment 3a, which shows that the total delivered volume was 1,864,016 DT and the total delivered cost was $8,651,680.50. The detail provided in the Customer Transaction Summaries includes the price and volume by delivering pipeline with a breakdown into baseload purchases, swing purchases and storage withdrawals.

Section 2a Storage Injections

This section shows the actual storage costs and volumes based on the optimized storage fill and the benchmark inventory cost based on the planned storage fill using a ratable, one-seventh per month approach as has been used in past asset management arrangements. The costs for the purchase of supply for injection are the actual delivered costs for the volumes purchased during the month and scheduled to be injected into the storage fields. Similar to the flowing costs, the volumes purchased and scheduled for injection may not be the specific volumes purchased for injection. The actual cost of injections into the storage fields is shown by transaction on the Storage Injection Transaction Deal report (Attachment 4).

The Customer Inventory Cost is the monthly ratable injection volume and price. It is the benchmark for measurement of the savings to customers from optimized storage fill. Attachment 5 lists the actual and Customer and Inventory Costs by storage field.

Section 2b Realized Hedging Impact on Storage Transactions

Realized hedging gains/losses are calculated based on the final monthly settlements of any financial transactions that were used to hedge forward transactions designed to lock in cost savings for supplies injected into storage. These gains or losses are separated here but are already included in actual costs in Section 1. The realized financial transactions are listed in Attachment 7.

Section 2c Unrealized Hedging Impact on Storage Transactions

Unrealized activity represents the results of the forward transactions that have not been financially settled or physically delivered. At the end of the fiscal year the unrealized Mark to Market value, as calculated on March 31, 2011, was booked to earnings for the April 2010 through March 2011 period. As this unrealized value, as of March 31, 2011, was realized in the April 2011 through March 2012 period it was reversed from the April 2010 through March 2011 earnings so that it was not double counted. This value was $77,925.05 and was recovered over the course of the April 2011 to March 2012 fiscal year. The storage long/short position is the excess gas that was injected into the storage capacity that is not currently being used by the firm sales customers. The MTM is the mark to market position of the financial and physical transactions that were executed to lock in margins (savings).. (Attachment 8) The Physical Storage Value is the difference in the inventory cost of the actual inventory and the Benchmark inventory. (Attachment

5) The Forward Storage Value is the value of the excess gas in storage when there is more gas in inventory then the benchmark inventory, or the forecasted replacement cost, when there is less gas in inventory than the benchmark inventory. These forward values are priced based on the future markets. The future carry costs on storage inventory are estimated for the remaining months of the fiscal year. The cost of collateral on the settled derivative positions is calculated to adjust the realized gains by the carry costs associated with financial storage hedges. The Mark to Market value calculated on March 31 is also decayed for the seven summer months as recovered and the cost of collateral associated with the early payment of this value is also captured as a cost of carry at the applicable monthly tariff rate currently at 9.925%. The posted collateral associated with trading clearport futures is added into the cost of carry calculation at the monthly money pool rate. (Attachment 9) The total unrealized value is the net value of the future activity; financial hedges, cost of excess gas in storage and expected forward value at market prices, adjusted for the earnings already booked in the previous contract year.

Position and Margin Sharing

The last section on the Monthly Summary Report is a calculation of the total savings to customers under the Plan and any incentive earned by the Company. This total is the sum of the Savings from Section 1 and the Total Unrealized value shown at the end of Section 2c. Any realized savings from storage activity is embedded in the Section 1 flowing supply activity which includes the impact of any optimization hedges for months where the NYMEX contract has closed.

The final value of the savings from all optimization transactions, as shown on page 2, is $5,498,990.90. This value is currently $4,498,990.90 more than the $1,000,000 guaranteed to customers. This amount of savings would be split with the customer's receiving $3,599,192.72 plus the $1,000,000 guaranteed amount and the Company receiving $899,798.18.

Narragansett Monthly Summary

National Grid Natural Gas Portfolio Management Plan

As of 3/31/2012

1) FLOWING SUPPLY /STORAGE WITHDRAWAL

Month	Actual Flowing Cost			3rd Party Sales		Customer Costs			Earnings
	VOLUME	$		VOLUME	$	VOLUME	$		
Apr-11	2,734,806	$ 12,493,857.71		870,790	$ 4,199,853.87	1,864,016	$ 8,651,680.50		$ 357,676.66
May-11	1,965,022	$ 9,175,650.51		995,739	$ 4,692,801.31	969,283	$ 4,607,279.18		$ 124,429.98
Jun-11	1,542,024	$ 7,256,269.73		880,625	$ 4,391,764.88	661,402	$ 3,084,031.35		$ 219,526.50
Jul-11	2,217,766	$ 10,338,727.59		1,634,705	$ 8,649,828.91	583,058	$ 2,701,775.87		$ 1,012,877.19
Aug-11	1,919,135	$ 8,404,546.67		1,356,506	$ 6,001,705.54	562,627	$ 2,577,481.09		$ 174,639.89
Sep-11	1,787,541	$ 7,317,624.49		1,214,993	$ 5,004,653.52	572,549	$ 2,344,334.38		$ 31,363.41
Oct-11	2,011,583	$ 7,765,656.46		935,281	$ 3,652,770.00	1,076,300	$ 4,334,803.76		$ 221,917.30
Nov-11	3,230,533	$ 11,645,998.56		1,281,437	$ 4,968,299.36	1,949,096	$ 7,425,435.85		$ 747,736.65
Dec-11	4,034,182	$ 14,909,756.17		4,034,182	$ 3,021,983.11	3,269,395	$ 12,467,547.81		$ 579,774.75
Jan-12	4,470,341	$ 15,870,067.75		503,209	$ 2,228,593.64	3,967,132	$ 14,619,132.23		$ 977,658.12
Feb-12	3,870,951	$ 11,855,342.17		349,911	$ 1,178,286.98	3,521,040	$ 11,137,394.05		$ 460,338.86
Mar-12	2,965,396	$ 8,346,053.53		2,965,396	$ 1,487,613.26	2,466,096	$ 7,240,492.53		$ 382,052.26
Total	**32,749,279**	**$ 125,379,551.34**		**17,022,774**	**$ 49,478,154.38**	**21,461,994**	**$ 81,191,388.60**		**$ 5,289,991.57**

2a) STORAGE INJECTION

Month	Actual Storage Costs			Customer Inventory Costs	
	VOLUME	$		VOLUME	$
Apr-11	502,649	$ 2,268,918.98		462,644	$ 2,126,602.65
May-11	465,806	$ 2,181,390.20		420,856	$ 1,997,832.80
Jun-11	364,391	$ 1,687,582.31		434,910	$ 2,022,959.29
Jul-11	312,554	1,462,025		448,818	$ 2,105,051.10
Aug-11	457,153	$ 2,147,583.01		362,247	$ 1,717,697.39
Sep-11	663,839	$ 2,693,165.50		450,450	$ 1,872,952.60
Oct-11	358,206	$ 1,406,793.73		495,254	$ 1,985,172.62
Nov-11	113,581	$ 427,205.28		68,425	$ 1,187,507.27
Dec-11	186,291	$ 691,157.83		90,072	$ 326,410.05
Jan-12	249,388	$ 840,061.39		91,118	$ 303,057.50
Feb-12	118,365	$ 316,714.07		64,866	$ 188,472.37
Mar-12	297,135	$ 745,265.35		141,642	$ 377,181.10
Total	4,089,359	$ 16,867,862.69		3,531,302	$ 16,210,896.74

2b) REALIZED HEDGING

Month	Hedging Gain/(Loss)*		
Apr-11		$ 19,090.44	
May-11		$ 1,392.79	
Jun-11		$ 784.99	
Jul-11		$ (1,246.71)	
Aug-11		$ 15,917.36	
Sep-11		$ (102,533.52)	
Oct-11		$ 11,085.78	
Nov-11		$ (1,909.00)	
Dec-11		$ (18,228.00)	
Jan-11		$ -	
Feb-11		$ -	
Mar-11		$ -	
Total		$ (75,645.87)	

*** Realized hedging gains and losses are included monthly in 3rd party sales dollars**

2c) UNREALIZED ACTIVITY

Storage position long/(short) (dt)	*373,169*		
Contract Year 2010-2011 Value Booked to Earnings (MTM at 3/31/2011)		$ 77,925.05	
MTM (Financial and Physical) as of March 28th, 2012		$ 342,690.12	
Physical Storage Value as of March 28th, 2012		$ (1,200,508.02)	
Forward Storage Value (purchase)/sale		$ 988,892.19	
Carry Cost and Cost of Collateral -March 2012		$ -	

TOTAL UNREALIZED VALUE — $ 208,999.33

TOTAL REALIZED AND UNREALIZED VALUE — $ 5,498,990.90

MARGIN SHARING

Customer Guarantee	$ 1,000,000.00
Customer Excess Earnings	$ 3,599,192.72
National Grid Incentive	$ 899,798.18