Thomas R. Teehan
Senior Cousel

October 22, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: National Grid, Annual Gas Cost Recovery Filing
<u>Rebuttal Testimony</u>

Dear Ms. Massaro:

Enclosed please find ten (10) copies of the rebuttal testimony and attachments of Gary L. Beland, the rebuttal testimony of Stephen A. Mc Cauley, and rebuttal testimony and attachments of Elizabeth Arangio in the above-referenced proceeding.

Please be advised that the Company is seeking protective treatment of confidential Attachment EDA-4R, as permitted by Commission Rule 1.2(g) and by R.I.G.L. § 38-2-2(4)(i)(B). The Company has submitted a Motion for Protective Treatment under separate cover along with a copy of the confidential Attachment EDA-4R to the Commission pending a determination on the Company's Motion. The Company has submitted a redacted version of the response in this filing for the public record.

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

Enclosures

cc: Docket 4097 Service List

Certificate of Service

I hereby certify that a copy of the cover letter and / or any materials accompanying this certificate has been electronically transmitted, sent via U.S. mail or hand-delivered to the individuals listed below.

________________________________ October 22, 2009

Joanne M. Scanlon Date

Docket No. 4097 – National Grid – Annual Gas Cost Recovery Filing ("GCR") - Service List as of 10/5/09

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File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02888	Lmassaro@puc.state.ri.us Plucarelli@puc.state.ri.us Sccamara@puc.state.ri.us	401-780-2107 401-941-1691

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2009
Docket No. 4097

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 1, 2009, National Grid filed with the Commission its Annual Gas Cost Recovery filing in this docket. On October 22, 2009, the Company filed the rebuttal testimony of Elizabeth Arangio. That testimony contained an attachment EDA-4R, containing information relative to the Company's Distrigas contract and relative to forecasted basis numbers for which National Grid is requesting confidential treatment 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 forecasts of basis numbers that appear at Attachment EDA-4R. The Company seeks protective treatment for its basis number information which provides price forecasts at specific points where gas is purchased. This information is assembled by a third-party and purchased by the Company subject to contractual agreement to maintain it as proprietary and confidential information.

The Company has also redacted confidential pricing information from its FCS contract with Distrigas. The Company seeks protective treatment for that information because it is proprietary and competitively sensitive information that is the subject of a confidentiality agreement between the Company and Distrigas.

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to those previously identified portions of its responses to Direct Energy's first set of data requests.

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: October 22, 2009

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

NATIONAL GRID

DOCKET No. 4097

REBUTTAL TESTIMONY

OF

GARY L. BELAND

October 22, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gary L. Beland. My business address is 40 Sylvan Road, Waltham Massachusetts, 02451-1120.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes. I previously submitted pre-filed testimony in this docket on September 1, 2009.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the concerns Mr. Oliver expressed in his direct testimony regarding the following components of the Company's GCR filing: (1) recovery of the short-term borrowing costs associated with the collateral requirements for hedging and (2) the design winter throughput used in the development of the proposed GCR rate. (Oliver Direct at 14) Additionally, I will discuss the bill impact associated with Mr. Oliver's proposed GCR charges based on Mr. Oliver's proposed change to the NGPMP credit amount to be included in this year's GCR

Q. PLEASE DESCRIBE MR. OLIVER'S CONCERNS RELATIVE TO THE RECOVERY OF BORROWING COSTS ASSOCIATED WITH COLLATERAL REQUIREMENTS FOR HEDGING.

A. Specifically, Mr. Oliver conditionally supports the Company's proposal subject to reviewing the specific tariff language that the Company intends to file to implement the proposal. In addition, Mr. Oliver recommends that any tariff should include provisions that in cases where the collateral is in the form of a letter of credit, and not in cash, recovery should reflect the costs of securing and maintaining the letter of credit or the costs of an equivalent amount of short term borrowing. (Oliver Direct at 21). To address these issues, this testimony includes a modified tariff that incorporates a definition of how the carrying costs on hedge collateral will be calculated and recovered.

Q. PLEASE DESCRIBE HOW THE COMPANY PROPOSES TO CALCULATE THE CARRYING COSTS ON HEDGE COLLATERAL.

A. The specific definitions and the terms and conditions as to how the Company proposes to calculate the carrying costs on hedge collateral have been added to the Tariff RIPUC NG-GAS No. 101, Section 1, Schedule B. (see Attachment GLB-1R). Simplified, the formula for calculating carrying cost is:

Hedge Collateral Carrying Cost = STIP-STIR-IP+IR

Where:

STIP = Short term interest paid for posted collateral
STIR = Short term interest saved on received collateral
IP = Interest paid on collateral received
IR = Interest received on collateral posted

The Hedge Collateral Carrying Cost will be calculated by taking the Average Hedge Collateral Balance times the Short Term Borrowing Rate (STBR) divided by 12 less any interest saved on received collateral (received collateral X STBR/12), plus interest paid by the Company on received collateral, less any interest earned on balances held by an exchange or counterparty. Note that the Hedge Collateral Cost may be positive and due to the Company or negative and due to customers. For purposes of the calculation, the Average Hedge Collateral Balance will be the sum of the daily collateral balances divided by the number of days in the month and the Short Term Borrowing Rate will be the interest rate for the month published in the Wall Street Journal.

Q. WHAT IS THE CONCERN RAISED IN MR. OLIVER'S TESTIMONY ABOUT THE DESIGN WINTER THROUGHPUT?

A. Mr. Oliver makes a comparison of the Design Winter throughput requirements used in this year's GCR rate calculation with what was used in last year's calculation and questions why a portion of the forecasted design winter sales requirements are shifted from the months of January, February, and March to the months of November and December. (Oliver testimony at pages 14-16). He also questions whether the change in the design forecast may affect the Company's gas supply planning.

Q. WHAT CAUSED THE SHIFT IN DESIGN WINTER REQUIREMENTS BETWEEN THE MONTHS DESCRIBED BY MR. OLIVER?

A. The shift was primarily the result of a change in methodology. In previous filings the Company had used billing cycle design degree days while in this filing the Company used calendar month design degree days.

Q. WHY DID THE COMPANY CHANGE TO USING CALENDAR MONTH DEGREE DAYS?

A. The Company refined its calculation to use calendar month degree days because the fixed gas costs being allocated are based on the supply portfolio which is constructed specifically to meet design winter sendout loads. Using billing cycle design degree days introduces a source of variation from year to year based on changes in the Company's billing schedule. In addition, the calculation of an allocation percentage includes throughput from November through March. Using the billing cycle design degree days does not capture the fact that the billing month of April has more degree days than November, and thus does not achieve the purpose of the cost allocation, which is to allocate based on peak season demand responsibility.

Q. WHAT IS THE IMPACT OF THE CHANGE?

A. Actually, the impact of the change is quite small. For example, the GCR charge for residential heat would drop from $1.0892 to $1.0891 if you substituted the degree day pattern used last year for the pattern used this year.

Q. WHAT ABOUT MR. OLIVER'S CONCERNS ABOUT THE SUPPLY PORTFOLIO?

A. The shift which Mr. Oliver was concerned about has no effect whatsoever on the Company's supply portfolio planning process.

Q. WHAT IS THE BILL IMPACT ASSOCIATED WITH MR. OLIVER'S PROPOSED GCR CHARGES?

A. Mr. Oliver's testimony includes the calculation of GCR charges based on his recommendation to increase the level of NGPMP credits. (Oliver Testimony at page 29 and Exhibit BRO -10) The bill impact that would be associated with implementation of rates proposed by Mr. Oliver is that there would be a larger reduction compared with the rates proposed by the Company. Attachment GLB-2R shows that the average residential heating customer using 922 therms per year would see a decrease of $16.08 per year. When combined with the rate reduction in the DAC, the overall impact would be a reduction of 1.6% in the customer's annual gas cost.

Q. DOES THE COMPANY ACCEPT MR. OLIVER'S RECOMMENDED CHANGE RELATIVE TO NGPMP CREDITS IN THE GCR CHARGE?

A. Yes.

Q. DOES THIS CONCULDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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DEFINITIONS

Actual Transportation Quantity:	The quantity of gas actually received during the Gas Day as measured by the metering equipment at the Point(s) of Receipt, adjusted for the applicable Company Fuel Allowance.
Aggregation Pool:	One or more transportation Customer accounts whose gas usage is aggregated into a Marketer's account for operational purposes, including but not limited to nominating, scheduling and balancing gas deliveries to specified Point(s) of Receipt.
AGT Costs:	Advanced Gas Technology program costs as approved by the Rhode Island Public Utilities Commission.
Average Normalized Winter Day Usage:	A customer's average normal winter day's usage, based on their actual gas usage during the most recent November through March period, adjusted for normal degree days, as approved in the most recent rate case proceeding.
BTU content factor:	One British thermal unit, i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60^o) Fahrenheit. A Therm is one hundred thousand Btus. The BTU content factor for a given volume, shall be calculated by the Company on a seasonal basis at the end of October and the end of April based upon an average of the Transporting Pipeline's prior six-month experience of recorded BTU factors.
Capacity Release Revenues:	Revenues derived from the sale of capacity upstream of the city-gate.
Company Fuel Allowance**:**	The quantity in Therms (as calculated on a percentage basis) by which the gross amount of gas received for Customer's account at the Point(s) of Receipt is reduced in kind in order to compensate the Company

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DEFINITIONS

	for gas loss and unaccounted for, Company use or similar quantity-based adjustment.
Consumption Algorithm:	A mathematical formula used to calculate a Customer's daily consumption based on the Customer's historical base load and heat use per heating degree day factor.
Critical Day:	Defined as any day where supply resource constraints are expected to adversely impact the operation of the Company's distribution system. Generally, this occurs at) forty-four (44) Degree Days or colder. A Critical Day may also occur under other conditions, such as pipeline emergencies, malfunctions or unusual, out-of-season weather conditions.
Customer:	Any party(s) that has obtained service from the Company pursuant to the General Terms and Conditions or pursuant to the Transportation Terms and Conditions
Daily Index:	The mid-point of the range of prices for the respective New England Citygates as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Algonquin citygates" and "Daily Price Survey, Midpoint, Citygates Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)." In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of gas as the basis for this calculation until such time that RIPUC approves a suitable replacement.
Deferred Balance:	The difference between incurred costs and revenues received.
Deferred Gas Cost Balance:	The difference between gas costs incurred and gas revenues received.

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DEFINITIONS

Dekatherm (Dt):	Ten Therms or one million Btu's (MMBtu)
Design Winter Sales:	Sales of Residential Non-Heating, Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I during November through March based on design winter temperatures.
Electronic Bulletin Board:	An internet web site which allows both the Company and Marketers to electronically post nominations and other transportation-related information.
Environmental Response Costs:	All reasonable and prudently incurred costs associated with evaluation, remediation, clean-up, litigation, claims, judgments, insurance recovery (net of proceeds), and settlements arising out of the company's utility-related ownership, operation, or use of: (1) manufactured gas production and storage facilities and disposal sites where wastes and materials from such facilities were deposited; (2) mercury regulators; and (3) meter disposal. Also included are the reasonable and prudently incurred costs for acquiring plant, property and equipment to facilitate remediation and other appropriate environmental management objectives in connection with the above sites, properties, and activities. The Company will use its best efforts to minimize Environmental Response Costs consistent with applicable regulatory requirements and sound environmental management policies and practices.
Forecasted Daily Usage (FDU):	Customer's estimated daily consumption for the next gas day as calculated by the Company based upon a forecast of heating degree days and the consumption algorithm.
Gas Day:	A period of twenty-four (24) consecutive hours beginning at 10:00 am (EST) and ending at 10:00 am (EST) the next calendar day.

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DEFINITIONS

Gas Usage:	The actual quantity of gas used by the Customer as measured by the Company's metering equipment at the Point of Delivery and converted to Therms.
Hedge Collateral:	Funds the Company is required to put up as collateral on hedge positions by an exchange or counterparty, or funds it receives from an exchange or counterparty as collateral.
Hedge Collateral Carrying Costs:	For the month being calculated, carrying costs are the total of the following: (1) For each exchange or counterparty holding the Company's collateral, the monthly short term borrowing rate (The monthly average for the rate for high grade 30-day commercial paper sold through dealers by major corporations as published in the Wall Street Journal) times the average hedge collateral daily balance for the month divided by 12. Less (2) for each exchange or counterparty where the Company holds their collateral, the monthly short term borrowing rate times the average hedge collateral daily balance for the month divided by 12. Less (3) any interest paid to the Company by the exchange or counterparty on the collateral funds it holds. The Company will recover carrying costs from customers or credit customers for carrying costs through the Gas Adjustment. In the event the Company chooses to meet its collateral obligations by posting a letter of credit or other non-cash instrument, the carrying cost will be the direct costs of the letter of credit or alternative non-cash instrument.
Imbalance:	The difference between the Actual Transportation Quantity and Gas Usage.
Interest on Deferred Balance:	Interest revenue/expense required to finance the deferred balance based on the Bank of America Prime

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DEFINITIONS

	Rate less 200 basis points (2%) as in effect from time to time.
Inventory Finance Charge:	Finance charges associated with the storage of natural gas as calculated using a working capital calculation.
Local Storage Costs:	Costs associated with the investment, operations and maintenance of natural gas storage downstream of the city-gate.
Low Income Assistance Programs:	Programs for assisting low income customers with their energy bills including, but not limited to, Low Income Heating Assistance (LIHEAP) and Low Income Weatherization, as in effect from time to time.
Marginal Gas Cost:	The variable cost of the Company's marginal source of supply for the Gas Day. Incremental Cost is a synonymous term.
Marketer:	An entity meeting the eligibility requirements of Section 6 Schedule C, Item 5.03 that is designated in a Transportation Service Application by the Customer to act on its behalf for nomination, notification, scheduling, balancing and receipt of communications, and which has executed a Marketer Aggregation Pool Service Agreement. A Customer may designate itself as the Marketer provided that they have an executed service agreement with the Transporting Pipeline or provide proof of contract to purchase the gas at the Company's city gate.
Maximum Daily Quantity:	The maximum quantity of gas a customer is authorized to use during the gas day.
Monthly Index:	The simple average of the Daily Indices for the applicable month.
Net Insurance Recoveries:	Proceeds recovered from insurance providers and third parties for Environmental Response Costs, less the

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DEFINITIONS

	cost of obtaining such proceeds through claims, settlements, and litigation.
New Customer:	A Customer taking a supply of gas at a Point of Delivery that has not been previously served on a firm sales service basis by the Company.
Non-Firm Transportation Margin:	Margins derived from the transportation of natural gas to non-firm customers downstream of the city gate.
Off-System Sales Margins:	Margins derived from the sale of natural gas upstream of the city-gate.
Pipeline Costs:	Costs associated with the entitlement and transmission of natural gas on the interstate pipeline system.
Pipeline Shipper(s):	The party(s) from whom Marketer has purchased gas to be delivered to and transported by the Company.
Point of Delivery:	A location at which the Company's distribution facilities are interconnected with the Customer's facility.
Point(s) of Receipt:	Outlet side of the measuring station at the interconnection between the Transporting Pipeline and the Company's distribution facilities where gas will be received by the Company for transportation service in its service territory.
Pool Balancing Revenues:	Revenues associated with Pool Balancing service, as derived in Section 2, Schedule A, Item 4.0.
Purchased Gas Working Capital:	Working capital required to finance gas costs.
Reconciliation Amount:	The Deferred balance at the end of September.
Refunds:	Refunds from pipeline, storage and suppliers.

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DEFINITIONS

Scheduled Transportation Quantity:	The quantity of gas scheduled by the Marketer to be received by the Company for Customer's account during the Gas Day at the Point of Receipt, including the applicable Company Fuel Allowance.
Service Quality Performance Fund:	Deferred account containing accumulated Service Quality adjustments.
Supplier Costs:	Costs associated with the entitlement and purchase of natural gas.
Therm:	An amount of gas having a thermal content of 100,000 Btus.
Transportation Imbalance Revenues:	Revenues associated with daily and monthly imbalances for transportation customers, as included in the Company's Terms and Conditions of Firm Transportation.
Transporting Pipeline:	The party(s) engaged in the business of rendering transportation service of natural gas in interstate commerce subject to the jurisdiction of the Federal Energy Regulatory Commission, which are transporting gas for Marketer to a Point of Receipt of the Company.
Upstream Storage Costs:	Costs associated with the entitlement, injection, withdrawal and storage of natural gas upstream of the city-gate.
Working Capital:	Amounts required to finance the Company's activities prior to the receipt of revenue.

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GAS COST RECOVERY CLAUSE

1.0 GENERAL:

1.1 Purpose:

The purpose of this clause is to establish procedures that allow the Company, subject to the jurisdiction of the Rhode Island Public Utilities Commission ("RIPUC"), to annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity in order to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, purchased gas working capital, and to credit supplier refunds, capacity credits from off-system sales and revenues from capacity release transactions.

The Gas Cost Recovery Clause shall include all costs of firm gas, including, but not limited to, commodity costs, demand charges, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory costs, requirements for purchased gas working capital, all applicable taxes, and deferred gas costs. Any costs recovered through the application of the Gas Charge shall be identified and explained fully in the annual filing.

1.2 Applicability:

The Gas Charge shall be calculated separately for the following rate groups:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Large C&I High Load Factor, Extra Large C&I High Load Factor ;
(2) Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large C&I Low Load Factor, and Extra Large C&I Low Load Factor;
(3) ;FT-2 Firm Transportation – Marketers
(4) Natural Gas Vehicles

The Company will make annual Gas Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Gas Charge shall become effective with consumption on or after November 1st as designated by the Company.

GAS COST RECOVERY CLAUSE

In the event of any change subsequent to the November effective date which would cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than one (1) percent of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance.

Unless otherwise notified by the RIPUC, the Company shall submit the Gas Charge filings no later than 60 days before they are scheduled to take effect. The Annual Reconciliation filing will be made by August 1 of each year containing actual data for the twelve months ending June 30 of that year.

2.0 GAS CHARGE FACTORS

2.1 Gas Charges to Sales Customers: The Gas Charge consists of five (5) components: (1) Supply Fixed Costs, (2) Storage Fixed Costs, (3) Supply Variable Costs (4) Storage Variable Product Costs, and (5) Storage Variable Non-product Costs. These components shall be computed using a forecast of applicable costs and volumes for each firm rate schedule based on the following formula:

$$GC_S = FC_S + SFC_S + VC_S + SVC_S + SVNC_s$$

Where:

GC_S Gas Charge applicable to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I sales.

FC_S Supply Fixed Cost Component for a rate classification. See Item 3.1 for calculation.

SFC_S Storage Fixed Cost Component for a rate classification. See Item 3.2 for calculation.

GAS COST RECOVERY CLAUSE

VC_S Supply Variable Cost Component for a rate classification. See Item 3.3 for calculation.

SVC_S Storage Variable Product Cost Component for a rate classification. See Item 3.4 for calculation.

$SVNC_S$ Storage Variable Non-product Cost Component for a rate classification. See Item 3.5 for calculation.

This calculation will be adjusted for the uncollectible percentage approved in the most recent rate case proceeding and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule D.

2.2 Gas Charge to FT-2 <u>Marketers</u>: The FT-2 Firm Transportation Marketer Gas Charge (GC_M) recovers costs associated with storage and peaking resources and is calculated as follows:

$$GC_M = SFC_S + SVNC_S$$

Where:

GC_M Gas Charge applicable to Marketers for FT-2 Firm Transportation Service

SFC_S Storage Fixed Cost Component. See Item 3.2 for calculation.

$SVNC_S$ Storage Variable Non-product Cost Component. See Item 3.5 for calculation.

2.3 Gas Charge to Natural <u>Gas Vehicles</u>: The Natural Gas Vehicle Gas Charge (GC_{NGV}) recovers costs associated with natural gas distributed to the public at Company owned NGV stations and is calculated as follows:

GAS COST RECOVERY CLAUSE

$GC_{NGV} = FC_S + VC_S$

Where:

GC_{NGV} Gas Charge applicable to Natural Gas Vehicle (NGV) Service

FC_S Supply Fixed Cost Component. See Item 3.1 for calculation.

VC_S Supply Variable Cost Component. See Item 3.3 for calculation.

3.0 GAS CHARGE CALCULATIONS

3.1 Supply Fixed Cost Component:

The Supply Fixed Cost Component shall include all fixed costs related to the purchase of firm gas, including, but not limited to, pipeline and supplier fixed reservation costs, demand charges, and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Fixed Cost Component shall be identified and explained fully in the annual filing.

The Supply Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$FC_S = \frac{DWS_S * (TC_{FC} - TR_{FC} + WC_{FC} + R_{FC})}{Dt_S}$$

Where:

FC_S Supply Fixed Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I,

GAS COST RECOVERY CLAUSE

Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

DWS_S	Percent of Design Winter Sales (November - March) for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.
TC_{FC}	Total Supply Fixed Costs, including, but not limited to pipeline and supplier reservation.
TR_{FC}	Credits to Supply Fixed Costs relating to supply services, including, but not limited to balancing charge revenues, capacity release revenues, off-system sales margins and refunds.
WC_{FC}	Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.
R_{FC}	Deferred Fixed Cost Account Balance as of October 31, as derived in Item 6.0 less the amount guaranteed to customers under the Natural Gas Portfolio Management Plan (NGPMP) and, following approval by the Commission, the net positive revenue from optimization transactions reduced by the guaranteed amount and the Company incentive under the Plan.
Dt_S	Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

GAS COST RECOVERY CLAUSE

3.2 Storage Fixed Cost Component:

The Storage Fixed Cost Component shall include all fixed costs related to the operations, maintenance and delivery of storage, including, but not limited to, supply related portion of local production and storage costs as determined in the most recent rate case proceeding, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Fixed Cost Component shall be identified and explained fully in the annual filing.

The Storage Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$SFC_S = \frac{DWT_S * (TC_{SFC} - TR_{SFC} + WC_{SFC} + R_{SFC})}{Dt_S}$$

Where:

SFC_S Storage Fixed Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I or FT-2 service.

DWT_S Percent of Design Winter Throughput (November - March) for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I ,Extra Large Low and High Load C&I, or FT-2 service.

TC_{SFC} Total Fixed Storage Costs, all fixed costs, including, but not limited to supply related local production and storage costs, and taxes on storage. The level of supply related local

GAS COST RECOVERY CLAUSE

production and storage costs shall be as determined in most recent rate case proceeding.

TR_{SFC} Total Credits to Storage Fixed Costs

WC_{SFC} Working Capital requirements associated with Total Storage Fixed Costs. See Item 5.0 for calculation.

R_{SFC} Deferred Storage Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_S Forecast of annual sales related to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I. Extra Large Low and High Load C&I and throughput related to FT-2 service.

3.3 Supply Variable Cost Component: The Supply Variable Cost Component shall include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Variable Cost Component shall be identified and explained fully in the annual filing.

The Supply Variable Cost Component is calculated for each applicable rate schedule as follows:

$$VC = \frac{TC_{VC} - TR_{VC} + WC_{VC} + R_V}{Dt_{VC}}$$

Where:

VC Supply Variable Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating,

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GAS COST RECOVERY CLAUSE

Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

TC_{VC} Total Supply Variable Costs, including, but not limited to pipeline, supplier, commodity-billed pipeline transition costs and any hedge, hedging related cost or the carrying cost on hedge collateral.

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TR_{VC} Total Credits to Supply Variable Costs, including, but not limited to balancing commodity charge revenues and transportation imbalance charges.

WC_{VC} Working Capital requirements associated with Total Supply Variable Costs. See item 5.0 for calculation.

R_V Deferred Cost Account Balance as of October 31, as derived in Item 6.0 plus the net of any Gas Procurement Incentives/Penalties associated with the Gas Procurement Incentive Plan.

Dt_{VC} Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

3.4 Storage Variable Product Cost <u>Component</u>: The Storage Variable Product Cost Component shall include all variable storage product costs of firm gas, including, but not limited to, storage commodity costs, taxes on storage commodity and other gas Storage expense incurred to transport supplies, transportation fees, inventory commodity costs, inventory financing costs and requirements for purchased gas working capital. Any costs recovered through the application of the Storage

GAS COST RECOVERY CLAUSE

Variable Product Cost Component shall be identified and explained fully in the annual filing.

The Storage Variable Product Cost Component is calculated for each applicable rate schedule as follows:

$$VSC = \frac{TC_{VSC} - TR_{VSC} + WC_{VSC} + R_{VSC}}{Dt_{VSC}}$$

Where:

VSC Storage Variable Product Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, or Extra Large Low and High Load C&I.

TC_{VSC} Total Storage Variable Product Costs, including, but not limited to pipeline, storage, and commodity-billed pipeline transition costs associated with storage delivery.

TR_{VSC} Total Credits to Storage Variable Product Costs.

WC_{VSC} Working Capital requirements associated with Total Storage Variable Product Costs. See item 5.0 for calculation.

R_{VSC} Deferred Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_{VSC} Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.

3.5 Storage Variable Non-product Cost

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GAS COST RECOVERY CLAUSE

Component: The Storage Variable Non-product Cost Component shall include all variable costs related to the operations, maintenance and delivery of storage, as determined in the most recent rate case proceeding, injection and withdrawal costs, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Variable Non-Product Cost Component shall be identified and explained fully in the annual filing.

The Storage Variable Non-product Cost Component is calculated for each applicable rate schedule as follows:

$$SVNC_S = \frac{TC_{SVNC} - TR_{SVNC} + WC_{SVNC} + R_{SVNC}}{Dt_S}$$

Where:

$SVNC_S$ Storage Variable Non-product Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I or FT-2 service.

TC_{SVNC} Total Storage Variable Non-product Costs, all variable costs, including, but not limited to supply related local production and storage costs, injection and withdrawal costs, and taxes on storage. The level of supply related local production and storage costs shall be as determined in most recent rate case proceeding.

TR_{SVNC} Total Credits to Storage Variable Non-product Costs.

GAS COST RECOVERY CLAUSE

WC_{SVNC} Working Capital requirements associated with Total Storage Variable Non-product Gas Costs. See Item 5.0 for calculation.

R_{SVNC} Deferred Storage Variable Non-product Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_S Forecast of annual sales related to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I. Extra Large Low and High Load C&I and throughput related to FT-2 service.

4.0 POOL BALANCING

4.1 Purpose: This section establishes a procedure to allow the Company, subject to the jurisdiction of the RIPUC, to adjust on an annual basis its rates for firm pool balancing service set forth in Section 6, Schedule C, Item 5.04 of RIPUC NG-GAS No. 101

4.2 Calculation: BAL = (FC + SFC + SVC) * 1%

Where:

BAL Balancing Charge for Pool Balancing Service applicable to Marketer pool throughput per percent of balancing service elected.

FC Fixed Cost Component as calculated in Item 3.1 above.

SFC Storage Fixed Cost Component as calculated in Item 3.2 above.

SVC Storage Variable Product Cost Component as calculated in Item 3.4 above.

5.0 WORKING CAPITAL

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GAS COST RECOVERY CLAUSE

REQUIREMENT:

$WC_M = WCA_M * [DL / 365] * COC$

Where:

WC_M Working Capital requirements of Supply Fixed (WC_{FC}), Storage Fixed (WC_{SFC}), Supply Variable (WC_{SV}), Storage Variable Product (WC_{SVC}) or Storage Variable Non-product (WC_{SVNC}) Cost Components.

WCA_M Working Capital Allowed in the Supply Fixed, Storage Fixed, Supply Variable, Storage Variable Product, or Storage Variable Non-product Cost component calculations.

DL Days Lag approved in the most recent rate case proceeding.

COC Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended June as presented in the Company's annual Distribution Adjustment Clause (DAC) filing in support of the Earnings Sharing Mechanism (ESM). The long-term debt component will be based on the Company's actual long-term borrowing rate as presented in the Company's annual DAC filing.

6.0 DEFERRED GAS COST ACCOUNT:

The Company shall maintain five (5) separate Deferred Gas Cost Accounts: (1) Supply Fixed Costs and revenues, (2) Storage Fixed Costs and revenues, (3) Supply Variable Costs and revenues, (4) Storage Variable Product Costs and revenues, and (5) Storage Variable Non-product Costs

GAS COST RECOVERY CLAUSE

and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

An amount equal to the allowable costs incurred, less:

1. Gas Revenues collected adjusted for the RIGET and uncollectible % approved in the most recent rate case proceeding;

2. Credits to costs, including but not limited to GCR Deferred Responsibility surcharge/credits and Transitional Sales Service (TSS) surcharge revenues.

3. Monthly interest based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning-of-the-month balance and the balance after entries 1. and 2. above.

7.0 REFUNDS

7.1 During Refund Period

If the Company receives a cash refund resulting from gas supply overcharges during a historical "refund period," where the historical "refund period" is the most recent 60-month period, and the amount of the refund equals or exceeds 2% of the Company's total gas costs for the prior fiscal year, the amount to be refunded to any firm customer who used gas during the refund period and who is not on the suspended debt file shall be equal to:

The customers' billed usage during Refund Period X

$$\frac{\text{Amount to be Refunded}}{\text{Firm Sales during Refund Period}}$$

where the Amount to be Refunded equals Total Amount of Refund minus the incremental costs incurred by the Company in effecting the distribution of the supplier refund.

The customer shall receive this amount in the form of:

GAS COST RECOVERY CLAUSE

1. A lump-sum bill credit if the customer's account is active or if the customer's final bill has not been paid; or

2. A personal check if the customers account is closed and paid in full and the amount of the check exceeds $25; or

3. A combination bill credit/personal check if the amount of the credit exceeds the unpaid balance of the customer's final bill.

The total amount of individually calculated refunds of $2 or less to have been paid by check will be credited to the Deferred Gas Cost Account. Checks which are not deliverable or paid within 90 days of the mailing shall be canceled and also credited to the Deferred Gas Cost Account.

Should any canceled refund checks later become a liability of the Company, the cost shall be debited to the Deferred Gas Cost Account.

7.2 Prior To Refund Period: If the Company receives a cash refund resulting from gas supply overcharges during periods prior to the historical refund period, then the refund shall be credited to the appropriate Deferred Cost Account.

7.3 Less Than 2% If the amount of the refund is less than 2% of the Company's total gas cost for the prior fiscal year, it shall be credited to the appropriate Deferred Cost Account.

8.0 WEIGHTED AVERAGE UPSTREAM PIPELINE TRANSPORTATION COST

At the request of a marketer or the Division, the Company will provide within 21 days an estimate of the pipeline path costs for the next GCR year beginning November 1. The estimate will be based on the most recent GCR filing updated for current commodity pricing and other known changes which would significantly affect the factor.

GAS COST RECOVERY CLAUSE

Concurrent with the annual GCR filing, the Company shall calculate the final weighted average cost of upstream pipeline transportation capacity. The cost shall be applicable to capacity release under the Transportation Terms and Conditions effective November 1 of each year or at such time as the Commission approves the rates.

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

Residential Heating:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	600	$1,026	$1,041	($16)	-1.5%	$0	($10.47)	($5.05)	$0.00
	664	$1,119	$1,136	($17)	-1.5%	$0	($11.60)	($5.62)	$0.00
	730	$1,216	$1,235	($19)	-1.5%	$0	($12.76)	($6.13)	$0.00
	794	$1,307	$1,328	($21)	-1.5%	$0	($13.86)	($6.67)	$0.00
	857	$1,396	$1,418	($22)	-1.6%	$0	($14.97)	($7.18)	$0.00
Average Customer	**922**	**$1,486**	**$1,510**	**($24)**	**-1.6%**	**$0**	**($16.08)**	**($7.75)**	**$0.00**
	987	$1,576	$1,602	($25)	-1.6%	$0	($17.21)	($8.28)	$0.00
	1,051	$1,665	$1,692	($27)	-1.6%	$0	($18.31)	($8.82)	$0.00
	1,114	$1,750	$1,779	($29)	-1.6%	$0	($19.41)	($9.35)	$0.00
	1,180	$1,839	$1,870	($31)	-1.6%	$0	($20.58)	($9.95)	$0.00
	1,247	$1,929	$1,961	($32)	-1.6%	$0	($21.75)	($10.45)	$0.00

Residential Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	600	$988	$1,004	($16)	-1.5%	$0	($10.47)	($5.05)	$0.00
	664	$1,079	$1,096	($17)	-1.6%	$0	($11.60)	($5.62)	$0.00
	730	$1,173	$1,192	($19)	-1.6%	$0	($12.76)	($6.13)	$0.00
	794	$1,263	$1,283	($21)	-1.6%	$0	($13.86)	($6.67)	$0.00
	857	$1,349	$1,371	($22)	-1.6%	$0	($14.97)	($7.18)	$0.00
Average Customer	**922**	**$1,437**	**$1,461**	**($24)**	**-1.6%**	**$0**	**($16.08)**	**($7.75)**	**$0.00**
	987	$1,526	$1,551	($25)	-1.6%	$0	($17.21)	($8.28)	$0.00
	1,051	$1,612	$1,640	($27)	-1.7%	$0	($18.31)	($8.82)	$0.00
	1,114	$1,696	$1,725	($29)	-1.7%	$0	($19.41)	($9.35)	$0.00
	1,180	$1,783	$1,814	($31)	-1.7%	$0	($20.58)	($9.95)	$0.00
	1,247	$1,871	$1,904	($32)	-1.7%	$0	($21.75)	($10.45)	$0.00

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

Residential Non-Heating:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	123	$297	$302	($5)	-1.5%	$0	($3.66)	($1.01)	$0
	137	$317	$323	($5)	-1.6%	$0	($4.10)	($1.14)	$0
	147	$332	$337	($6)	-1.7%	$0	($4.38)	($1.22)	$0
	161	$352	$358	($6)	-1.7%	$0	($4.81)	($1.37)	$0
	176	$373	$380	($7)	-1.8%	$0	($5.26)	($1.48)	$0
Average Customer	**189**	**$392**	**$399**	**($7)**	**-1.8%**	**$0**	**($5.62)**	**($1.60)**	**$0**
	202	$411	$419	($8)	-1.8%	$0	($6.04)	($1.70)	$0
	217	$433	$441	($8)	-1.9%	$0	($6.48)	($1.84)	$0
	231	$453	$462	($9)	-1.9%	$0	($6.87)	($1.93)	$0
	241	$467	$476	($9)	-1.9%	$0	($7.17)	($2.02)	$0
	256	$489	$498	($10)	-2.0%	$0	($7.64)	($2.17)	$0

Residential Non-Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	123	$280	$285	($5)	-1.6%	$0	($3.66)	($1.01)	$0
	137	$300	$305	($5)	-1.7%	$0	($4.10)	($1.14)	$0
	147	$314	$319	($6)	-1.8%	$0	($4.38)	($1.22)	$0
	161	$333	$340	($6)	-1.8%	$0	($4.81)	($1.37)	$0
	176	$354	$361	($7)	-1.9%	$0	($5.26)	($1.48)	$0
Average Customer	**189**	**$373**	**$380**	**($7)**	**-1.9%**	**$0**	**($5.62)**	**($1.60)**	**$0**
	202	$391	$399	($8)	-1.9%	$0	($6.04)	($1.70)	$0
	217	$412	$420	($8)	-2.0%	$0	($6.48)	($1.84)	$0
	231	$431	$440	($9)	-2.0%	$0	($6.87)	($1.93)	$0
	241	$445	$455	($9)	-2.0%	$0	($7.17)	($2.02)	$0
	256	$466	$476	($10)	-2.1%	$0	($7.64)	($2.17)	$0

Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

C & I Small:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	824	$1,703	$1,725	($21)	-1.2%	$0	($14)	($7)	$0
	916	$1,830	$1,854	($24)	-1.3%	$0	($16)	($8)	$0
	1,003	$1,950	$1,975	($26)	-1.3%	$0	($17)	($8)	$0
	1,092	$2,071	$2,100	($28)	-1.3%	$0	($19)	($9)	$0
	1,179	$2,187	$2,218	($30)	-1.4%	$0	($21)	($10)	$0
Average Customer	**1,269**	**$2,304**	**$2,337**	**($33)**	**-1.4%**	**$0**	**($22)**	**($11)**	**$0**
	1,359	$2,421	$2,456	($35)	-1.4%	$0	($24)	($11)	$0
	1,447	$2,536	$2,573	($37)	-1.5%	$0	($25)	($12)	$0
	1,535	$2,650	$2,690	($40)	-1.5%	$0	($27)	($13)	$0
	1,622	$2,763	$2,805	($42)	-1.5%	$0	($28)	($14)	$0
	1,715	$2,884	$2,928	($44)	-1.5%	$0	($30)	($14)	$0

C & I Medium:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	7,117	$10,162	$10,345	($184)	-1.8%	$0	($124)	($60)	$0
	7,884	$11,179	$11,382	($204)	-1.8%	$0	($137)	($66)	$0
	8,649	$12,194	$12,417	($223)	-1.8%	$0	($151)	($73)	$0
	9,416	$13,211	$13,454	($243)	-1.8%	$0	($164)	($79)	$0
	10,185	$14,232	$14,495	($263)	-1.8%	$0	($178)	($86)	$0
Average Customer	**10,950**	**$15,246**	**$15,529**	**($283)**	**-1.8%**	**$0**	**($191)**	**($92)**	**$0**
	11,715	$16,261	$16,564	($303)	-1.8%	$0	($204)	($98)	$0
	12,484	$17,281	$17,604	($322)	-1.8%	$0	($218)	($105)	$0
	13,251	$18,299	$18,641	($342)	-1.8%	$0	($231)	($111)	$0
	14,016	$19,314	$19,676	($362)	-1.8%	$0	($244)	($118)	$0
	14,783	$20,331	$20,713	($382)	-1.8%	$0	($258)	($124)	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

C & I LLF Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	37,532	$51,711	$52,680	($969)	-1.8%	$0	($654)	($315)	$0
	41,573	$57,123	$58,197	($1,074)	-1.8%	$0	($725)	($349)	$0
	45,616	$62,539	$63,717	($1,178)	-1.8%	$0	($795)	($383)	$0
	49,660	$67,955	$69,238	($1,283)	-1.9%	$0	($866)	($417)	$0
	53,699	$73,365	$74,752	($1,387)	-1.9%	$0	($936)	($451)	$0
Average Customer	**57,742**	**$78,780**	**$80,272**	**($1,491)**	**-1.9%**	**$0**	**($1,006)**	**($485)**	**$0**
	61,785	$84,196	$85,791	($1,596)	-1.9%	$0	($1,077)	($519)	$0
	65,824	$89,606	$91,306	($1,700)	-1.9%	$0	($1,147)	($553)	$0
	69,868	$95,022	$96,827	($1,805)	-1.9%	$0	($1,218)	($587)	$0
	73,911	$100,437	$102,346	($1,909)	-1.9%	$0	($1,288)	($621)	$0
	77,952	$105,850	$107,863	($2,013)	-1.9%	$0	($1,359)	($655)	$0

C & I HLF Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	37,970	$47,014	$48,465	($1,451)	-3.0%	$0	($1,132)	($319)	$0
	42,061	$51,924	$53,532	($1,607)	-3.0%	$0	($1,254)	($353)	$0
	46,151	$56,834	$58,597	($1,764)	-3.0%	$0	($1,376)	($388)	$0
	50,240	$61,741	$63,661	($1,920)	-3.0%	$0	($1,498)	($422)	$0
	54,329	$66,649	$68,725	($2,076)	-3.0%	$0	($1,620)	($456)	$0
Average Customer	**58,418**	**$71,557**	**$73,790**	**($2,232)**	**-3.0%**	**$0**	**($1,742)**	**($491)**	**$0**
	62,508	$76,466	$78,855	($2,389)	-3.0%	$0	($1,864)	($525)	$0
	66,596	$81,373	$83,918	($2,545)	-3.0%	$0	($1,986)	($559)	$0
	70,686	$86,282	$88,983	($2,701)	-3.0%	$0	($2,107)	($594)	$0
	74,775	$91,190	$94,047	($2,858)	-3.0%	$0	($2,229)	($628)	$0
	78,867	$96,101	$99,115	($3,014)	-3.0%	$0	($2,351)	($662)	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

C & I LLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	189,450	$230,824	$235,718	($4,893)	-2.1%	$0	($3,302)	($1,591)	$0
	209,855	$255,298	$260,718	($5,420)	-2.1%	$0	($3,658)	($1,763)	$0
	230,255	$279,765	$285,713	($5,947)	-2.1%	$0	($4,013)	($1,934)	$0
	250,655	$304,233	$310,708	($6,474)	-2.1%	$0	($4,369)	($2,106)	$0
	271,059	$328,705	$335,706	($7,001)	-2.1%	$0	($4,724)	($2,277)	$0
Average Customer	**291,462**	**$353,177**	**$360,705**	**($7,528)**	**-2.1%**	**$0**	**($5,080)**	**($2,448)**	**$0**
	311,865	$377,648	$385,703	($8,055)	-2.1%	$0	($5,436)	($2,620)	$0
	332,269	$402,120	$410,702	($8,582)	-2.1%	$0	($5,791)	($2,791)	$0
	352,669	$426,588	$435,697	($9,109)	-2.1%	$0	($6,147)	($2,962)	$0
	373,069	$451,055	$460,691	($9,636)	-2.1%	$0	($6,502)	($3,134)	$0
	393,474	$475,529	$485,692	($10,163)	-2.1%	$0	($6,858)	($3,305)	$0

C & I HLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	184,661	$217,665	$224,722	($7,057)	-3.1%	$0	($5,506)	($1,551)	$0
	204,549	$240,720	$248,537	($7,817)	-3.1%	$0	($6,099)	($1,718)	$0
	224,435	$263,772	$272,349	($8,577)	-3.1%	$0	($6,692)	($1,885)	$0
	244,321	$286,825	$296,162	($9,337)	-3.2%	$0	($7,284)	($2,052)	$0
	264,206	$309,876	$319,973	($10,097)	-3.2%	$0	($7,877)	($2,219)	$0
Average Customer	**284,094**	**$332,931**	**$343,788**	**($10,857)**	**-3.2%**	**$0**	**($8,470)**	**($2,386)**	**$0**
	303,982	$355,986	$367,602	($11,617)	-3.2%	$0	($9,063)	($2,553)	$0
	323,867	$379,037	$391,414	($12,377)	-3.2%	$0	($9,656)	($2,720)	$0
	343,753	$402,090	$415,226	($13,137)	-3.2%	$0	($10,249)	($2,888)	$0
	363,639	$425,142	$439,039	($13,896)	-3.2%	$0	($10,842)	($3,055)	$0
	383,527	$448,197	$462,853	($14,656)	-3.2%	$0	($11,435)	($3,222)	$0

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

NATIONAL GRID

DOCKET No. 4097

REBUTTAL TESTIMONY

OF

Stephen A Mc Cauley

October 22, 2009

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 in the Energy Portfolio Management organization. As Director, I am responsible for all financial hedging activity for the eight National Grid regulated 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 the Company 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. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is respond to the issues raised in the Testimony of Bruce Oliver on behalf of the Division concerning the level and benefits of the Company's Gas Procurement Incentive Plan. ('GPIP") Specifically, Mr. Oliver argues that the Company should not be granted the full amount under the GPIP for this filing and that the Company's incentives under the GPIP should be eliminated or significantly modified going forward. (Oliver Direct at 17-21)

Q. DOES THE COMPANY BELIEVE IT SHOULD BE GRANTED THE FULL AMOUNT OF THE INCENTIVE ASSOCIATED WITH THE GPIP?

A. Yes. The GPIP became effective on June 1, 2003. In Section II of the Plan it states that the maximum limits for incentives earned or penalties paid by National Grid would be in place for at least the first two years of the program (through June 30, 2005). The trial period on these caps was put in place to ensure that the program was neither unduly beneficial nor detrimental to the company. Since the company has only exceeded the limits once in six years it demonstrates that the temporary cap was not necessary and is why this issue has not been addressed before. An incentive program without limits encourages the company to dedicate its resources to maximize the benefits to the customers. As the incentive is structured most of the benefit is retained by the customers. Removing the incentive limits encourages the Company to maximize the benefits to Customers since both the Customers' and the Company's incentives will always be aligned.

Q. DOES THE COMPANY BELIEVE THE ADOPTION OF THE NGPMP IN APRIL 2009 NEGATES THE REASON FOR CONTINUATION OF THE GPIP?

A. No. When the Company proposed the Natural Gas Procurement Management Plan, ('NGPMP") it highlighted as one benefit that it would not reduce or impact the effectiveness of the GPIP. Both of these programs can and do work independently from one another and provide separate and distinct benefits to the customers.

Q. DO YOU AGREE WITH MR. OLIVER'S OBSERVATION THAT LAST YEAR'S CHANGE TO THE GPIP WAS INEFFECTIVE IN ENCOURAGING THE COMPANY TO EXECUTE HEDGES IN MONTHS THAT ARE GREATER THAN 8 MONTHS IN THE FUTURE?

A. No, I do not. From December 1, 2008, the beginning of the incentive modification, through June 30, 2009 the Company has executed 2,700,000 DT of discretionary hedges. Of those discretionary positions executed, 2,400,000 DT or 89% have been executed for months greater than eight months prior to delivery.

The Company's goal is to execute discretionary volumes such that the average price will be less than the average mandatory price to ensure that the discretionary volumes are an incremental benefit to customers by being made at a price less than the mandatory hedge price.

Q. HAVE THE DISCRETIONARY VOLUMES OF THE GPIP BEEN BENEFICIAL TO THE CUSTOMERS?

A. The goal of encouraging the Company to execute discretionary hedges in times of weakness in the market and when prices are below the projected mandatory price has been achieved. In the incentive year ending June 30, 2009 the discretionary volumes were executed $2.575 below the mandatory hedge price with a total incremental benefit to the mandatory hedge price of $8,634,933. As of June 30, 2009 discretionary volumes of 3,050,000 DT have been executed for the incentive year ending June 30, 2010 and are projected to be $2.25 below the mandatory hedge price for a total benefit of $6,878,674. This benefit will remain regardless of where future prices end up for the coming incentive year.

Q. SHOULD THE INCENTIVE COMPONENT OF THE GPIP BE ELIMINATED AS MR. OLIVER HAS RECOMMENDED?

A. No. It would not be beneficial to customers to eliminate an incentive program that has resulted in a benefit to the customers for the three most recent years of over $20M. The Customer benefits are aligned with the incentive in times of falling market prices. Customers should continue to derive the benefits in such market conditions by encouraging the Company to dedicate its resources to seek these opportunities and execute the discretionary hedges when it is in the Customers' best interest to do so. The Company believes that the incentive program has accomplished and continues to accomplish the goals that it was designed to achieve. The Company, however, also believes that it would be productive for it to work with the Division to review the current incentive parameters and to discuss any modification to the purchasing incentive component or any aspects of the GPIP. Accordingly, the Commission should not eliminate or modify the GPIP in this proceeding, but should give the Company and the Division time to discuss these matters further and return to the Commission with a reasoned proposal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

NATIONAL GRID

DOCKET No. 4097

REBUTTAL TESTIMONY

OF

Elizabeth Arangio

October 22, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Elizabeth Arangio. My business address is 40 Sylvan Road, Waltham Massachusetts, 02451-1120.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes. I previously submitted pre-filed testimony in this docket on September 1, 2009.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. To respond to the testimony of Rebecca Bachelder submitted on behalf of Direct Energy, which requested that the Company continue to use a three-year historical average of basis to calculate the 2009/10 Weighted Average Cost of Gas ("WACOG") and to provide an updated calculation of the 2009/10 WACOG using the three-year moving average method.

Q. IS NATIONAL GRID WILLING TO CONSIDER THE REQUEST FROM THE DIRECT TESTIMONY OF REBECCA BACHELDER THAT THE USE OF THE THREE-YEAR MOVING AVERAGE METHOD BE USED TO CALCULATE THE 2009/10 WACOG?

A. Yes. National Grid is willing to use the three-year moving average method in order to calculate the 2009/10 WACOG. (Provided in Attachment EDA-4R) National Grid will work with marketers to understand the ramifications, if any, to the competitive marketplace of implementing the forward basis strip methodology in subsequent annual filings and provide advanced notice of any future changes in methodology.

Q. DOES THIS CONCULDE YOUR REBUTTAL TESTIMONY?

A. Yes.

National Grid
Summary of Transportation Capacity Release
Pipeline Path Availability and Pricing
November 2009 - October 2010

Path to City Gate	As of 9/1/09 Existing Releases	Total Available	Remaining Available	Cost /Dth	New Credit/ Surcharge	Old Credit / Surcharge
Company Weighted Average				**$0.963**		
Tennessee Zone 1	5,992	6,000	8	$0.941	$0.022	($0.205)
Algonquin @ Lambertville, NJ	2,334	2,714	380	$0.716	$0.248	($0.198)
Texas Eastern - South Texas Algonquin @ Lambertville, NJ	4,044	4,044	0	$1.185	($0.221)	($0.044)
Texas Eastern - West La Algonquin @ Lambertville, NJ	6,000	6,000	0	$1.145	($0.181)	($0.363)
Texas Eastern - East La Algonquin @ Lambertville, NJ	5,491	5,500	9	$1.141	($0.177)	($0.313)
Columbia (Maumee/Downington) at 5:1 ratio**	0	1,000	1,000	$0.638	$0.326	$0.035
Totals	23,861	25,258	1,397			

** 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.

Gas Year 2009 - 2010
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	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	
TETCO STX M1 TO M3 DEMAND	$/Dth	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
TETCO USAGE STX TO M3	$/Dth	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	$0.072	
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	
8/24/2009 NYMEX	$/Dth	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5.896	$6.018	
SUPPLY AREA BASIS (12 month average)	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
BILLING UNITS														
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
TETCO STX M1 TO M3 DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
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														
TETCO USAGE STX TO M3	Dth	132,695	139,148	139,148	125,682	139,148	132,695	137,118	132,695	137,118	137,118	132,695	137,118	1,622,379
ALGONQUIN USAGE	Dth	122,570	127,196	127,196	114,886	127,196	122,570	126,656	122,570	126,656	126,656	122,570	126,656	1,493,378
PURCHASE VOLUMES	Dth	132,695	139,148	139,148	125,682	139,148	132,695	137,118	132,695	137,118	137,118	132,695	137,118	1,622,379
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
TETCO STX M1 TO M3 FUEL	%	7.63%	8.59%	8.59%	8.59%	8.59%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$333,881
TECCO WLA SUPPLY ZONE DEMAND	$	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$138,651
TETCO ELA SUPPLY ZONE DEMAND	$	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$116,442
TETCO STX M1 TO M3	$	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$546,271
ALGONQUIN AFT-E	$	$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	$	$9,488	$9,949	$9,949	$8,986	$9,949	$9,488	$9,804	$9,488	$9,804	$9,804	$9,488	$9,804	$116,000
ALGONQUIN USAGE	$	$1,581	$1,641	$1,641	$1,482	$1,641	$1,581	$1,634	$1,581	$1,634	$1,634	$1,581	$1,634	$19,265
PURCHASE COST	$	$521,305	$661,178	$701,809	$640,302	$708,906	$672,444	$703,498	$694,206	$733,801	$746,827	$732,157	$773,291	$8,289,723
TOTAL FIXED	$	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$1,425,302
TOTAL VARIABLE	$	$532,374	$672,768	$713,399	$650,770	$720,496	$683,513	$714,935	$705,275	$745,238	$758,265	$743,226	$784,728	$8,424,988
DELIVERED COST AT NYMEX	$	$522,525	$643,117	$679,724	$619,719	$686,117	$660,709	$690,630	$680,605	$718,336	$730,245	$715,303	$754,441	$8,101,471
NET NON-GAS VARIABLE COST	$	$9,849	$29,650	$33,676	$31,052	$34,379	$22,804	$24,305	$24,670	$26,903	$28,019	$27,923	$30,288	$323,517
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.081**	**$0.237**	**$0.269**	**$0.274**	**$0.274**	**$0.188**	**$0.194**	**$0.203**	**$0.215**	**$0.224**	**$0.230**	**$0.242**	**$0.219**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2009 - 2010
TEXAS EASTERN WEST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE
CITY GATE DELIVERED MDQ = 6,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
					UNIT PRICING									
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	
TETCO WLA M1 TO M3 DEMAND	$/Dth	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
TETCO USAGE WLA TO M3	$/Dth	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	
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	
8/24/2009 NYMEX	$/Dth	$4.31	$5.13	$5.42	$5.47	$5.47	$5.45	$5.51	$5.61	$5.73	$5.83	$5.90	$6.02	
SUPPLY AREA BASIS (12 month average)	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
					BILLING UNITS									
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	Dth	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	
TETCO ELA SUPPLY ZONE DEMAND	Dth	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	
TETCO WLA M1 TO M3 DEMAND	Dth	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	
ALGONQUIN AFT-E DEMAND	Dth	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
VARIABLE														
TETCO USAGE WLA TO M3	Dth	195,501	204,505	204,505	184,715	204,505	195,501	202,018	195,501	202,018	202,018	195,501	202,018	2,388,304
ALGONQUIN USAGE	Dth	181,855	188,718	188,718	170,455	188,718	181,855	187,917	181,855	187,917	187,917	181,855	187,917	2,215,694
PURCHASE VOLUMES	Dth	195,501	204,505	204,505	184,715	204,505	195,501	202,018	195,501	202,018	202,018	195,501	202,018	2,388,304
DELIVERED VOLUMES	Dth	180,000	186,000	186,000	168,000	186,000	180,000	186,000	180,000	186,000	186,000	180,000	186,000	2,190,000
					FUEL USE %									
TETCO WLA M1 TO M3 FUEL	%	6.98%	7.72%	7.72%	7.72%	7.72%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
FIXED														
TETCO WLA SUPPLY ZONE	$	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$205,714
TETCO ELA SUPPLY ZONE DEMAND	$	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$172,762
TETCO WLA M1 TO M3	$	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$810,491
ALGONQUIN AFT-E	$	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$430,351
VARIABLE														
TETCO USAGE WLA TO M3	$	$13,705	$14,336	$14,336	$12,948	$14,336	$13,705	$14,161	$13,705	$14,161	$14,161	$13,705	$14,161	$167,420
ALGONQUIN USAGE	$	$2,346	$2,434	$2,434	$2,199	$2,434	$2,346	$2,424	$2,346	$2,424	$2,424	$2,346	$2,424	$28,582
PURCHASE COST	$	$809,667	$1,015,267	$1,074,982	$980,372	$1,085,412	$1,032,342	$1,079,481	$1,064,405	$1,124,127	$1,143,318	$1,120,318	$1,182,308	$12,711,999
TOTAL FIXED	$	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$1,619,319
TOTAL VARIABLE	$	$825,717	$1,032,037	$1,091,753	$995,520	$1,102,182	$1,048,393	$1,096,066	$1,080,455	$1,140,712	$1,159,904	$1,136,368	$1,198,893	$12,908,002
DELIVERED VOLUMES AT NYMEX	$	$775,260	$954,180	$1,008,492	$919,464	$1,017,978	$980,280	$1,024,674	$1,009,800	$1,065,780	$1,083,450	$1,061,280	$1,119,348	$12,019,986
NET NON-GAS VARIABLE COST	$	$50,457	$77,857	$83,261	$76,056	$84,204	$68,113	$71,392	$70,655	$74,932	$76,454	$75,088	$79,545	$888,016
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.28**	**$0.42**	**$0.45**	**$0.45**	**$0.45**	**$0.38**	**$0.38**	**$0.39**	**$0.40**	**$0.41**	**$0.42**	**$0.43**	**$0.41**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2009 - 2010
TEXAS EASTERN EAST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE
CITY GATE DELIVERED MDQ = 5,500

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
					UNIT PRICING									
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	
TETCO ELA M1 TO M3 DEMAND	$/Dth	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
TETCO USAGE ELA TO M3	$/Dth	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	
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	
8/24/2009 NYMEX	$/Dth	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5.896	$6.018	
SUPPLY AREA BASIS (12 month average)	[redacted]													
NET COST AFTER BASIS														
					BILLING UNITS									
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	Dth	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	
TETCO ELA M1 TO M3 DEMAND	Dth	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	
ALGONQUIN AFT-E DEMAND	Dth	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	66,000
VARIABLE														
TETCO USAGE ELA TO M3	Dth	178,671	186,694	186,694	168,627	186,694	178,671	184,627	178,671	184,627	184,627	178,671	184,627	2,181,904
ALGONQUIN USAGE	Dth	166,700	172,991	172,991	156,250	172,991	166,700	172,257	166,700	172,257	172,257	166,700	172,257	2,031,053
PURCHASE VOLUMES	Dth	178,671	186,694	186,694	168,627	186,694	178,671	184,627	178,671	184,627	184,627	178,671	184,627	2,181,904
DELIVERED VOLUMES	Dth	165,000	170,500	170,500	154,000	170,500	165,000	170,500	165,000	170,500	170,500	165,000	170,500	2,007,500
					FUEL USE %									
TETCO ELA M1 TO M3 FUEL	%	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
FIXED														
TETCO ELA SUPPLY ZONE	$	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$158,365
TETCO ELA M1 TO M3	$	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$742,950
ALGONQUIN AFT-E	$	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$394,489
VARIABLE														
TETCO USAGE ELA TO M3	$	$12,418	$12,975	$12,975	$11,720	$12,975	$12,418	$12,832	$12,418	$12,832	$12,832	$12,418	$12,832	$151,642
ALGONQUIN USAGE	$	$2,150	$2,232	$2,232	$2,016	$2,232	$2,150	$2,222	$2,150	$2,222	$2,222	$2,150	$2,222	$26,201
PURCHASE COST	$	$758,049	$945,738	$1,000,253	$912,054	$1,009,774	$961,555	$1,005,239	$990,858	$1,046,041	$1,063,581	$1,041,958	$1,099,214	$11,834,314
TOTAL FIXED	$	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$1,295,804
TOTAL VARIABLE	$	$772,617	$960,945	$1,015,460	$925,789	$1,024,981	$976,124	$1,020,292	$1,005,426	$1,061,095	$1,078,635	$1,056,526	$1,114,268	$12,012,157
DELIVERED VOLUMES AT NYMEX	$	$710,655	$874,665	$924,451	$842,842	$933,147	$898,590	$939,285	$925,650	$976,965	$993,163	$972,840	$1,026,069	$11,018,321
NET NON-GAS VARIABLE COST	$	$61,962	$86,280	$91,009	$82,947	$91,835	$77,534	$81,008	$79,776	$84,130	$85,472	$83,686	$88,199	$993,836
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.376**	**$0.506**	**$0.534**	**$0.539**	**$0.539**	**$0.470**	**$0.475**	**$0.483**	**$0.493**	**$0.501**	**$0.507**	**$0.517**	**$0.495**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED

Gas Year 2009 - 2010
MAUMEE/DOWNINGTON COLUMBIA PATH TO CITY GATE
CITY GATE DELIVERED MDQ = 1,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
						UNIT PRICING								
FIXED														
COLUMBIA FTS DEMAND	$/Dth	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	
ALGONQUIN DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
COLUMBIA USAGE	$/Dth	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	
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	
8/24/2009 NYMEX	$/Dth	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5.896	$6.018	
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	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	
ALGONQUIN DEMAND	Dth	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
VARIABLE														
COLUMBIA USAGE	Dth	90,927	94,359	94,359	85,227	94,359	90,927	93,958	90,927	93,958	93,958	90,927	93,958	
ALGONQUIN USAGE	Dth	90,000	93,000	93,000	84,000	93,000	90,000	93,000	90,000	93,000	93,000	90,000	93,000	
PURCHASE VOLUMES MAUMEE	Dth	75,773	78,632	78,632	71,023	78,632	75,773	78,299	75,773	78,299	78,299	75,773	78,299	
PURCHASE VOLUMES DOWNINGTON	Dth	15,155	15,726	15,726	14,205	15,726	15,155	15,660	15,155	15,660	15,660	15,155	15,660	
DELIVERED VOLUMES MAUMEE	Dth	75,000	77,500	77,500	70,000	77,500	75,000	77,500	75,000	77,500	77,500	75,000	77,500	912,500
DELIVERED VOLUMES DOWNINGTON	Dth	15,000	15,500	15,500	14,000	15,500	15,000	15,500	15,000	15,500	15,500	15,000	15,500	182,500
						FUEL USE %								
COLUMBIA FUEL	%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
FIXED														
COLUMBIA FTS DEMAND	$	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$73,689
ALGONQUIN DEMAND	$	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$71,725
VARIABLE														
COLUMBIA USAGE	$	$1,946	$2,019	$2,019	$1,824	$2,019	$1,946	$2,011	$1,946	$2,011	$2,011	$1,946	$2,011	$23,708
ALGONQUIN USAGE	$	$1,161	$1,200	$1,200	$1,084	$1,200	$1,161	$1,200	$1,161	$1,200	$1,200	$1,161	$1,200	$14,126
PURCHASE COST MAUMEE	$	$332,075	$409,320	$432,281	$394,070	$436,291	$418,380	$437,259	$430,807	$454,563	$462,001	$452,478	$477,113	$5,136,637
PURCHASE COST DOWNINGTON	$	$72,178	$87,845	$92,437	$84,216	$93,239	$89,439	$93,407	$91,925	$96,868	$98,356	$96,259	$101,378	$1,097,546
TOTAL FIXED	$	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$145,414
TOTAL VARIABLE	$	$407,360	$500,384	$527,937	$481,193	$532,749	$510,926	$533,876	$525,838	$554,641	$563,567	$551,843	$581,701	$6,272,017
DELIVERED VOLUMES AT NYMEX	$	$387,630	$477,090	$504,246	$459,732	$508,989	$490,140	$512,337	$504,900	$532,890	$541,725	$530,640	$559,674	$6,009,993
NET NON-GAS VARIABLE COST	$	$19,730	$23,294	$23,691	$21,461	$23,760	$20,786	$21,539	$20,938	$21,751	$21,842	$21,203	$22,027	$262,024
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.219**	**$0.250**	**$0.255**	**$0.255**	**$0.255**	**$0.231**	**$0.232**	**$0.233**	**$0.234**	**$0.235**	**$0.236**	**$0.237**	**$0.239**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED

Gas Year 2009 - 2010
TENNESSEE ZONE 1 TO CITY GATE
CITY GATE DELIVERED MDQ = 6,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$/Dth	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	
8/24/2009 NYMEX	$/Dth	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5.896	$6.018	
SUPPLY AREA BASIS (12 month average)	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	Dth	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	Dth	195,270	201,779	201,779	182,252	201,779	192,864	199,293	192,864	199,293	199,293	192,864	199,293	2,358,623
PURCHASE VOLUMES	Dth	195,270	201,779	201,779	182,252	201,779	192,864	199,293	192,864	199,293	199,293	192,864	199,293	2,358,623
DELIVERED VOLUMES	Dth	180,000	186,000	186,000	168,000	186,000	180,000	186,000	180,000	186,000	186,000	180,000	186,000	2,190,000
TENNESSEE ZONE 1 TO 6 FUEL	%	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	
						TRANSPORTATION COST								
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$1,123,092
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$	$29,681	$30,670	$30,670	$27,702	$30,670	$29,315	$30,293	$29,315	$30,293	$30,293	$29,315	$30,293	$358,511
PURCHASE COST	$	$812,734	$1,005,889	$1,064,809	$971,057	$1,075,099	$1,022,392	$1,069,027	$1,054,021	$1,113,070	$1,132,003	$1,109,180	$1,170,467	$12,599,749
TOTAL FIXED	$	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$1,123,092
TOTAL VARIABLE	$	$842,415	$1,036,560	$1,095,479	$998,760	$1,105,770	$1,051,707	$1,099,319	$1,083,337	$1,143,363	$1,162,296	$1,138,496	$1,200,759	$12,958,259
DELIVERED VOLUMES AT NYMEX	$	$775,260	$954,180	$1,008,492	$919,464	$1,017,978	$980,280	$1,024,674	$1,009,800	$1,065,780	$1,083,450	$1,061,280	$1,119,348	$12,019,986
NET NON-GAS VARIABLE COST	$	$67,155	$82,380	$86,987	$79,296	$87,792	$71,427	$74,645	$73,537	$77,583	$78,846	$77,216	$81,411	$938,273
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.373**	**$0.443**	**$0.468**	**$0.472**	**$0.472**	**$0.397**	**$0.401**	**$0.409**	**$0.417**	**$0.424**	**$0.429**	**$0.438**	**$0.428**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2009 - 2010
ALGONQUIN LAMBERTVILLE TO CITY GATE
CITY GATE DELIVERED MDQ = 2,714

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
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	
8/24/2009 NYMEX	$/Dth	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5.896	$6.018	
SUPPLY AREA BASIS (12 month average)	$/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														
ALGONQUIN AFT-E USAGE	Dth	81,936	85,216	85,216	76,970	85,216	81,936	84,667	81,936	84,667	84,667	81,936	84,667	999,033
PURCHASE VOLUMES	Dth	81,936	85,216	85,216	76,970	85,216	81,936	84,667	81,936	84,667	84,667	81,936	84,667	999,033
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
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
						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	$	$1,057	$1,099	$1,099	$993	$1,099	$1,057	$1,092	$1,057	$1,092	$1,092	$1,057	$1,092	$12,888
PURCHASE COST	$	$390,246	$476,001	$500,884	$456,337	$505,230	$483,571	$505,024	$497,009	$523,736	$531,779	$520,442	$548,120	$5,938,378
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	$	$391,303	$477,100	$501,983	$457,330	$506,329	$484,628	$506,116	$498,066	$524,828	$532,871	$521,499	$549,212	$5,951,266
DELIVERED VOLUMES AT NYMEX	$	$350,676	$431,607	$456,175	$415,904	$460,465	$443,413	$463,494	$456,766	$482,088	$490,081	$480,052	$506,318	$5,437,040
NET NON-GAS VARIABLE COST	$	$40,627	$45,493	$45,809	$41,426	$45,864	$41,215	$42,622	$41,299	$42,740	$42,791	$41,447	$42,894	$514,225
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.499**	**$0.541**	**$0.544**	**$0.545**	**$0.545**	**$0.506**	**$0.507**	**$0.507**	**$0.508**	**$0.509**	**$0.509**	**$0.510**	**$0.519**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

REDACTED

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2009 - 2010 GCR PROJECTED PRICES**

August 1, 2009 Update **UNIT PRICES**

		NOV 2009	DEC	JAN 2010	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
PIPELINE FIXED COST UNIT PRICES													
ALGONQUIN AFT-E/AFT-1 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
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391
TEXAS EASTERN STX CDS DEMAND M3	$/Dth	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810	$6.810
TEXAS EASTERN WLA CDS DEMAND M3	$/Dth	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828	$2.828
TEXAS EASTERN ELA CDS DEMAND M3	$/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
TEXAS EASTERN ETX CDS DEMAND M3	$/Dth	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189
TETCO FTS DEMAND	$/Dth	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350
TETCO M1 TO M3 DEMAND M3	$/Dth	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142
TETCO SCT STX DEMAND	$/Dth	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724
TETCO SCT WLA DEMAND	$/Dth	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131
TETCO SCT ELA DEMAND	$/Dth	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950
TETCO SCT ETX DEMAND	$/Dth	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876
TETCO SCT DEMAND 1-3	$/Dth	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457
TETCO SCT STX DEMAND M2	$/Dth	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724
TETCO SCT WLA DEMAND M2	$/Dth	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131
TETCO SCT ELA DEMAND M2	$/Dth	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950
TETCO SCT ETX DEMAND M2	$/Dth	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876
TETCO SCT DEMAND 1-2	$/Dth	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388	$3.388
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599
TENNESSEE DRACUT	$/Dth	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930
TENNESSEE CONNEXION	$/Dth	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737
NETNE	$/Dth	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610
IROQUOIS	$/Dth	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597
NOVA	$/Dth	$4.515	$4.666	$4.666	$4.214	$4.666	$4.515	$4.666	$4.515	$4.666	$4.666	$4.515	$4.666
TRANSCANADA	$/Dth	$30.150	$31.155	$31.155	$28.140	$31.155	$30.150	$31.155	$30.150	$31.155	$31.155	$30.150	$31.155
DOMINION FTNN DEMAND	$/Dth	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358	$4.358
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460
TRANSCO DEMAND ZONE 3 TO 6.	$/Dth	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434
TRANSCO DEMAND ZONE 6	$/Dth	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119
NATIONAL FUEL DEMAND	$/Dth	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557
COLUMBIA FTS DEMAND	$/Dth	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010	$6.010
HUBLINE	$/Dth	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558
HUBLINE	$/Dth	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996
HUBLINE	$/Dth	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992
SUPPLIER FIXED COST UNIT PRICES													
DISTRIGAS FCS	$/Dth	[redacted]											

REDACTED

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2009 - 2010 GCR PROJECTED PRICES**

August 1, 2009 Update

		UNIT PRICES											
		NOV	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**
PIPELINE FIXED COST BILLING UNITS													
ALGONQUIN AFT-E/AFT-1 DEMAND	DTH	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950
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	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414
TEXAS EASTERN STX CDS 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 WLA CDS 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 ELA CDS 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 ETX CDS 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
TETCO M1 TO M3 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
TETCO FTS DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
TETCO SCT STX DEMAND	DTH	571	571	571	571	571	571	571	571	571	571	571	571
TETCO SCT WLA DEMAND	DTH	648	648	648	648	648	648	648	648	648	648	648	648
TETCO SCT ELA DEMAND	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
TETCO SCT ETX DEMAND	DTH	329	329	329	329	329	329	329	329	329	329	329	329
TETCO SCT DEMAND 1-3	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
TETCO SCT STX DEMAND M2	DTH	401	401	401	401	401	401	401	401	401	401	401	401
TETCO SCT WLA DEMAND M2	DTH	455	455	455	455	455	455	455	455	455	455	455	455
TETCO SCT ELA DEMAND M2	DTH	831	831	831	831	831	831	831	831	831	831	831	831
TETCO SCT ETX DEMAND M2	DTH	231	231	231	231	231	231	231	231	231	231	231	231
TETCO SCT DEMAND 1-2	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
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 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	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
TENNESSEE CONNEXION	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
NETNE	DTH	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
IROQUOIS	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
NOVA	DTH	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076
TRANSCANADA	DTH	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
DOMINION FTNN DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
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
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
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
HUBLINE	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
HUBLINE	DTH	500	500	500	500	500	500	500	500	500	500	500	500
HUBLINE	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
SUPPLIER FIXED COST BILLING UNITS													
DISTRIGAS FCS	DTH	[redacted]											

REDACTED

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2009 - 2010 GCR PROJECTED PRICES**

August 1, 2009 Update

		UNIT PRICES												
		NOV	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	
PIPELINE FIXED COST DOLLARS														
ALGONQUIN AFT-E/AFT-1 DEMAND	$	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	
ALGONQUIN AFT-3 DEMAND	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
ALGONQUIN AFT-ES/1S DEMAND	$	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	
TEXAS EASTERN STX CDS DEMAND M3	$	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	
TEXAS EASTERN WLA CDS DEMAND M3	$	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	
TEXAS EASTERN ELA CDS 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 ETX CDS 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	
TETCO 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	
TETCO M1 TO M3 DEMAND M3	$	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	
TETCO SCT STX DEMAND	$	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	
TETCO SCT WLA DEMAND	$	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	
TETCO SCT ELA DEMAND	$	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	
TETCO SCT ETX DEMAND	$	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	
TETCO SCT DEMAND 1-3	$	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	
TETCO 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	
TETCO SCT WLA DEMAND M2	$	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	
TETCO SCT ELA DEMAND M2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TETCO SCT ETX DEMAND M2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TETCO SCT DEMAND 1-2	$	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	
TENNESSEE DRACUT	$	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	
TENNESSEE CONNEXION	$	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	
NETNE	$	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	
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	
NOVA	$	$4,858	$5,020	$5,020	$4,534	$5,020	$4,858	$5,020	$4,858	$5,020	$5,020	$4,858	$5,020	
TRANSCANADA	$	$30,813	$31,840	$31,840	$28,759	$31,840	$30,813	$31,840	$30,813	$31,840	$31,840	$30,813	$31,840	
DOMINION FTNN DEMAND	$	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,906	$1,970	$1,970	$1,779	$1,970	$1,906	$1,970	$1,906	$1,970	$1,970	$1,906	$1,970	
TRANSCO DEMAND ZONE 3 TO 6.	$	$39	$40	$40	$36	$40	$39	$40	$39	$40	$40	$39	$40	
TRANSCO DEMAND ZONE 6	$	$4,416	$4,563	$4,563	$4,121	$4,563	$4,416	$4,563	$4,416	$4,563	$4,563	$4,416	$4,563	
NATIONAL FUEL DEMAND	$	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	
COLUMBIA FTS DEMAND	$	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	
HUBLINE	$	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	
HUBLINE	$	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	
HUBLINE	$	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	
WESTERLY LATERAL (Yankee)	$	[redacted]												
	$	**$2,657,158**	**$2,658,559**	**$2,657,290**	**$2,653,086**	**$2,657,290**	**$2,655,888**	**$2,657,290**	**$2,655,888**	**$2,657,290**	**$2,657,290**	**$2,655,888**	**$2,657,290**	**$31,880,207**
SUPPLIER FIXED COST DOLLARS														
DISTRIGAS FCS	$	[redacted]												
TOTAL PIPELINE FIXED DEMAND CHARGES		**$2,959,158**	**$2,960,559**	**$2,959,290**	**$2,955,086**	**$2,959,290**	**$2,957,888**	**$2,959,290**	**$2,957,888**	**$2,959,290**	**$2,959,290**	**$2,957,888**	**$2,959,290**	**$35,504,207**
TOTAL DEMAND UNITS DTH		5,062,752	5,534,368	5,534,368	4,998,784	5,534,368	4,912,752	4,928,652	4,314,203	4,458,010	4,458,010	4,314,203	4,928,652	**58,979,122**
100% LOAD FACTOR UNIT VALUE $/DTH														**0.6020**
Average rate per unit per month														**18.3102**
AVERAGE SYSTEM VARIABLE UNIT VALUE $/DTH														**0.3614**
TOTAL AVERAGE SYSTEM UNIT VALUE $/DTH													$	**0.9634**

REDACTED

National Grid
2009 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 REP 13 26-Aug-2009
Report 13 10:00:27

Natural Gas Supply VS. Requirements Units: MDT

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	
.	2009	2009	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010	Total
Forecast Demand													
RI Sales GCR	2,622,717	4,241,840	5,044,293	4,438,288	3,632,328	2,108,674	1,232,306	831,637	745,208	776,452	801,792	1,460,795	27,936,330
NON EX TR DE	313,107	469,231	497,378	474,703	426,684	275,870	166,121	134,770	109,906	111,264	127,782	170,974	3,277,790
Total Demand	2,935,824	4,711,071	5,541,671	4,912,991	4,059,012	2,384,544	1,398,427	966,407	855,114	887,716	929,574	1,631,769	31,214,120
Storage Injections													
TENN_8995	0	0	0	0	0	14,700	21,840	26,460	26,250	26,250	26,250	26,250	168,000
TENN_501	0	0	0	0	0	50,454	63,738	54,097	124,000	109,264	60,534	54,481	516,568
GSS 600045	0	0	0	0	0	150,000	137,632	137,632	137,632	137,632	137,632	123,869	962,029
GSS 300171	0	0	0	0	0	31,470	32,519	30,418	18,881	18,881	18,881	16,993	168,043
GSS 300169	0	0	0	0	0	43,771	31,000	28,279	20,610	20,610	20,610	18,549	183,429
GSS 300168	0	0	0	0	0	21,025	31,000	25,000	15,405	15,405	15,405	13,865	137,105
GSS 300170	0	0	0	0	0	60,000	62,000	60,000	62,000	49,034	49,034	44,131	386,199
TETCO_400221	0	0	0	0	0	120,000	124,000	120,000	118,804	118,804	118,804	106,923	827,335
TETCO_400515	0	0	0	0	0	8,730	5,664	5,664	5,664	5,664	5,664	5,098	42,148
TETCO 400185	0	0	0	0	0	10,918	5,199	5,199	5,199	5,199	5,199	4,679	41,592
COL FS 38010	0	0	0	0	0	24,000	24,800	24,000	20,396	20,396	20,396	18,356	152,344
LNG EXETER	13,000	0	16,462	0	0	58,610	5,400	0	35,100	65,790	10,500	3,100	207,962
LNG PROV	15,000	7,593	29,400	6,587	0	16,206	78,300	81,000	45,900	0	30,791	15,500	326,277
LNG VALLEY	2,700	15,570	5,438	9,028	0	6,184	0	0	2,700	17,910	2,700	2,790	65,020
Total Injections	30,700	23,163	51,300	15,615	0	616,068	623,092	597,749	638,541	610,839	522,400	454,584	4,184,051
Non-LNG Injections	0	0	0	0	0	535,068	539,392	516,749	554,841	527,139	478,409	433,194	3,584,792
Total LNG Injection	30,700	23,163	51,300	15,615	0	81,000	83,700	81,000	83,700	83,700	43,991	21,390	599,259
Total Req less LNG inj.	2,935,824	4,711,071	5,541,671	4,912,991	4,059,012	2,919,612	1,937,819	1,483,156	1,409,955	1,414,855	1,407,983	2,064,963	34,798,912

REDACTED

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
Sources of Supply													
TENN_ZONE_0	282,960	292,392	292,392	264,096	292,392	282,960	292,392	282,960	292,392	292,392	282,960	292,392	3,442,680
TENN_ZONE_1	0	441,768	445,104	409,964	315,884	0	0	0	0	0	0	0	1,612,720
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_DRACUT	29,700	53,188	138,354	125,891	30,690	450,000	357,877	0	0	10,424	0	465,000	1,661,124
TETCO_STX	274,620	283,774	283,774	256,312	283,774	274,620	283,774	274,620	283,774	283,774	274,620	283,774	3,341,210
TETCO_ELA	36,521	71,559	74,458	63,480	42,012	0	0	0	0	0	0	0	288,030
TETCO_WLA	204,888	279,014	284,466	255,388	234,220	0	0	0	0	0	0	0	1,257,976
TETCO_ETX	296,580	306,466	306,466	276,808	306,466	296,580	306,466	296,580	306,466	306,466	296,580	306,466	3,608,390
TETCO - NF	0	16,692	22,932	20,286	12,348	0	0	0	0	0	0	0	72,258
HUBLINE	0	47,085	103,540	73,148	4,931	240,000	248,000	201,297	94,938	89,413	134,728	248,000	1,485,080
M3_DELIVERED	0	117,409	125,513	103,225	42,973	0	0	0	0	0	0	0	389,120
MAUMEE_SUPP	885,069	902,619	907,355	806,912	868,104	682,970	15,200	14,400	16,000	16,396	12,396	8,356	5,135,777
BROADRUN_COL	289,616	296,040	305,908	276,304	286,172	234,125	9,600	9,600	4,396	4,000	8,000	10,000	1,733,761
Col Tran-Tet	0	52,351	111,542	84,426	7,360	0	0	0	0	0	0	0	255,679
TRAN WHART	0	930	2,170	2,170	0	0	0	0	0	0	0	0	5,270
TETCO B&W	12,432	35,076	37,296	31,080	12,846	0	0	0	0	0	0	0	128,730
DOM TET FTS	0	31,843	63,550	52,312	9,730	0	0	0	0	0	0	0	157,435
TETCO DOM	0	1,590	3,710	3,710	0	0	0	0	0	0	0	0	9,010
ANE	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	365,000
NIAGARA	24,000	31,000	31,000	28,000	31,000	30,000	12,521	5,000	0	0	0	31,000	223,521
DIST FCS VAP	[redacted]												
Total Pipeline Supply Deliveries	2,905,207	3,887,492	4,166,226	3,699,560	3,407,598	2,898,913	1,916,430	1,462,457	1,388,566	1,393,465	1,387,284	2,043,573	30,556,771
CITY GATE DELIVERED MDQ = 6,000 DTH													
Storage Withdrawals													
TENN_8995	8,400	29,494	56,116	56,031	17,960	0	0	0	0	0	0	0	168,001
TENN_501	1,517	131,936	131,936	119,168	131,936	0	0	0	0	0	0	0	516,493
GSS 600045	0	193,803	282,810	263,956	221,463	0	0	0	0	0	0	0	962,032
GSS 300171	0	38,851	64,972	49,096	15,751	0	0	0	0	0	0	0	168,670
GSS 300169	0	38,665	61,050	54,945	28,974	0	0	0	0	0	0	0	183,634
GSS 300168	0	26,277	41,490	38,724	31,266	0	0	0	0	0	0	0	137,757
GSS 300170	0	82,923	136,656	102,483	64,313	0	0	0	0	0	0	0	386,375
TETCO_400221	0	150,175	308,889	285,129	83,140	0	0	0	0	0	0	0	827,333
TETCO_400515	0	9,627	14,726	13,594	4,192	0	0	0	0	0	0	0	42,139
TETCO 400185	0	7,129	13,517	12,478	8,411	0	0	0	0	0	0	0	41,535
COL FS 38010	0	29,809	55,757	44,151	22,617	0	0	0	0	0	0	0	152,334
LNG EXETER	3,000	14,662	56,800	99,000	3,100	3,000	3,100	3,000	3,100	3,100	3,000	3,100	197,962
LNG PROV	15,000	27,993	117,000	43,787	15,500	15,000	15,500	15,000	15,500	15,500	15,000	15,500	326,280
LNG VALLEY	2,700	16,688	11,028	12,554	2,790	2,700	2,790	2,700	2,790	2,790	2,700	2,790	65,020
Total Withdrawals	30,617	798,032	1,352,747	1,195,096	651,413	20,700	21,390	20,700	21,390	21,390	20,700	21,390	4,175,565
Total Supply	2,935,824	4,685,524	5,518,973	4,894,656	4,059,011	2,919,613	1,937,820	1,483,157	1,409,956	1,414,855	1,407,984	2,064,963	34,732,336

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
8/24/2009 NYMEX	**$4.307**	**$5.130**	**$5.422**	**$5.473**	**$5.473**	**$5.446**	**$5.509**	**$5.610**	**$5.730**	**$5.825**	**$5.896**	**$6.018**	
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	
fuel	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	
Total Delivered	[redacted]												
TENNESSEE CONNEXION													
Basis	[redacted]												
usage	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	
fuel	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	
Total Delivered	[redacted]												
TENNESSEE ZN 1													
Basis	[redacted]												
usage to Zn 6	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	
fuel to Zn 6	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	
Total Delivered	[redacted]												
TENNESSEE DRACUT													
Basis	[redacted]												
usage	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	$0.0659	
fuel	0.89%	0.89%	0.89%	0.89%	0.89%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	[redacted]												
TETCO STX													
Basis	[redacted]												
Usage to M3	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M3	7.63%	8.59%	8.59%	8.59%	8.59%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	$0.0701	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M3	6.98%	7.72%	7.72%	7.72%	7.72%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M3	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												

TETCO ETX												
Basis	[redacted]											
Usage to M3	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695	$0.0695
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel to M3	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											
TETCO TO NF												
Basis	[redacted]											
Usage to M2	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192
Usage on NF	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086	$0.0086
Usage on Transco	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel to M2	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Fuel on NF	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%
Fuel on Transco	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Delivered to NF	[redacted]											
Delivered to Transco												
Delivered to Algonquin												
Total Delivered												
M3 DELIVERED												
Basis	[redacted]											
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											
MAUMEE SUPPLY												
Basis	[redacted]											
Usage on Columbia	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											
BROADRUN COLUMBIA												
Basis	[redacted]											
Usage on Columbia	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											
COLUMBIA TO AGT												
Basis	[redacted]											
Usage on Columbia	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											

REDACTED

TETCO to DOMINION TO B & W

Basis	[redacted]											
Usage on Dominion	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247	$0.0247
Usage to M2	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192
Usage on Tetco	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017
Usage on AGT	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294	$0.2294
Fuel to M2	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
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	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Delivered to Dominion	[redacted]											
Delivered to Tetco	[redacted]											
Delivered to Algonquin	[redacted]											
Total Delivered	[redacted]											

TRANSCO AT WHARTON

Basis	[redacted]											
Usage on Transco	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083	$0.0083
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Fuel on Transco	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											

AECO TO TENNESSEE - ANE II

Basis	[redacted]											
Transcanada usage	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Transcanada pressure chg	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017
Fuel on TCPL	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%	4.090%
Iroquois usage	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
Tennessee usage	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
Fuel on Iroquois	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
Fuel Tenn NET18	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Total Delivered	[redacted]											

NIAGARA TO TENNESSEE

Basis	[redacted]											
Tenn usage	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085
Tenn Fuel	2.09%	2.09%	2.09%	2.09%	2.09%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%
Total Delivered	[redacted]											

Tetco to B&W

Basis	[redacted]											
usage on Tetco	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426
usage on AGT	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229
fuel to ZN 3	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											

Dominion to Tetco FTS												
Basis	[redacted]											
usage on Tetco	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017
usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Tetco Fuel	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%
Fuel on AGT	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											
DISTRIGAS FCS												
Total Delivered	[redacted]											
Hubline												
Basis	[redacted]											
usage	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
fuel	1.02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%
Total Delivered	[redacted]											

Total delivered to the City Gas Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
Tennessee Zn 0												
Delivered Mmbtu	282,960	292,392	292,392	264,096	292,392	282,960	292,392	282,960	292,392	292,392	282,960	292,392
NYMEX $/Mmbtu Del	$4.4823	$5.3109	$5.6838	$5.7663	$5.7276	$5.8711	$5.9343	$6.0339	$6.1581	$6.2634	$6.3577	$6.4793
Total Delivered Cost	$1,268,298	$1,552,873	$1,661,899	$1,522,854	$1,674,711	$1,661,280	$1,735,132	$1,707,339	$1,800,571	$1,831,364	$1,798,970	$1,894,498
TENNESSEE 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	4.3215	5.1501	5.5230	5.6055	5.5668	5.7103	5.7735	5.8731	5.9973	6.1026	6.1969	6.3185
Total Delivered Cost	$1,503,865	$1,851,986	$1,986,073	$1,820,663	$2,001,829	$1,987,176	$2,076,138	$2,043,823	$2,156,619	$2,194,490	$2,156,515	$2,272,135
TENN ZONE 1												
Delivered Mmbtu	0	441,768	445,104	409,964	315,884	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$4.667	$5.544	$5.875	$5.937	$5.931	$5.845	$5.910	$6.013	$6.137	$6.239	$6.324	$6.445
Total Delivered Cost	$0	$2,449,188	$2,615,053	$2,433,862	$1,873,377	$0	$0	$0	$0	$0	$0	$0
TENN DRACUT												
Delivered Mmbtu at Historical	29,700	53,188	138,354	125,891	30,690	450,000	357,877	0	0	10,424	0	465,000
NYMEX $/Mmbtu Del	$4.925	$6.680	$8.172	$8.114	$6.537	$5.933	$5.996	$6.117	$6.255	$6.342	$6.391	$6.537
Total Delivered Cost	$146,286	$355,321	$1,130,579	$1,021,521	$200,620	$2,669,700	$2,145,833	$0	$0	$66,113	$0	$3,039,895
TETCO STX												
Delivered Mmbtu	274,620	283,774	283,774	256,312	283,774	274,620	283,774	274,620	283,774	283,774	274,620	283,774
NYMEX $/Mmbtu Del	$4.3821	$5.2841	$5.6643	$5.7474	$5.7077	$5.7553	$5.8176	$5.9118	$6.0335	$6.1426	$6.2505	$6.3666
Delivered Cost	$1,203,406	$1,499,503	$1,607,382	$1,473,138	$1,619,698	$1,580,518	$1,650,894	$1,623,501	$1,712,163	$1,743,108	$1,716,525	$1,806,674
TETCO WLA												
Delivered Mmbtu	204,888	279,014	284,466	255,388	234,220	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$4.5819	$5.5324	$5.8638	$5.9252	$5.9197	$5.7789	$5.8447	$5.9477	$6.0734	$6.1781	$6.2620	$6.3859
Delivered Cost	$938,771	$1,543,629	$1,668,060	$1,513,220	$1,386,508	$0	$0	$0	$0	$0	$0	$0
TETCO ELA												
Delivered Mmbtu	36,521	71,559	74,458	63,480	42,012	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$4.6774	$5.6206	$5.9503	$6.0112	$6.0060	$5.8329	$5.8982	$5.9997	$6.1244	$6.2290	$6.3137	$6.4359
Delivered Cost	$170,822	$402,207	$443,050	$381,592	$252,322	$0	$0	$0	$0	$0	$0	$0

Total delivered to the City Gas Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
TETCO ETX												
Delivered Mmbtu	296,580	306,466	306,466	276,808	306,466	296,580	306,466	296,580	306,466	306,466	296,580	306,466
NYMEX $/Mmbtu Del	$4.2518	$5.1320	$5.5024	$5.5821	$5.5463	$5.5754	$5.6362	$5.7275	$5.8468	$5.9553	$6.0660	$6.1788
Delivered Cost	$1,260,996	$1,572,799	$1,686,290	$1,545,166	$1,699,747	$1,653,542	$1,727,310	$1,698,664	$1,791,857	$1,825,109	$1,799,056	$1,893,604
TETCO - NF												
Delivered Mmbtu	0	16,692	22,932	20,286	12,348	0	0	0	0	0	0	0
Delivered $/Mmbtu	$5.1297	$6.0509	$6.3834	$6.4448	$6.4395	$6.3034	$6.3697	$6.4729	$6.5995	$6.7057	$6.7917	$6.9159
Delivered Cost	$0	$101,001	$146,385	$130,740	$79,515	$0	$0	$0	$0	$0	$0	$0
M3 DELIVERED												
Delivered Mmbtu	0	117,409	125,513	103,225	42,973	0	0	0	0	0	0	0
Delivered $/Mmbtu	$4.8248	$6.3753	$7.7406	$7.6256	$6.5717	$5.8942	$5.9603	$6.0829	$6.2214	$6.3095	$6.3551	$6.5069
Delivered Cost	$0	$748,520	$971,543	$787,155	$282,408	$0	$0	$0	$0	$0	$0	$0
Transco at Wharton												
Delivered Mmbtu	0	930	2,170	2,170	0	0	0	0	0	0	0	0
Delivered $/Mmbtu	$4.879	$6.419	$7.759	$7.648	$6.622	$5.946	$6.012	$6.137	$6.278	$6.367	$6.411	$6.566
Delivered Cost	$0	$5,969	$16,836	$16,597	$0	$0	$0	$0	$0	$0	$0	$0
MAUMEE_SUPP												
Delivered Mmbtu	885,069	902,619	907,355	806,912	868,104	682,970	15,200	14,400	16,000	16,396	12,396	8,356
NYMEX $/Mmbtu Del	$4.558	$5.439	$5.731	$5.779	$5.786	$5.730	$5.796	$5.904	$6.030	$6.127	$6.196	$6.328
Delivered Cost	$4,034,585	$4,909,568	$5,200,494	$4,663,118	$5,022,685	$3,913,372	$88,101	$85,013	$96,485	$100,452	$76,803	$52,873
BROADRUN_COL												
Delivered Mmbtu	289,616	296,040	305,908	276,304	286,172	234,125	9,600	9,600	4,396	4,000	8,000	10,000
Daily pricing wacog	$4.558	$5.439	$5.731	$5.779	$5.786	$5.730	$5.796	$5.904	$6.030	$6.127	$6.196	$6.328
Delivered Cost	$1,320,214	$1,610,235	$1,753,308	$1,596,752	$1,655,737	$1,341,520	$55,643	$56,675	$26,509	$24,507	$49,566	$63,275
COLUMBIA_AGT												
Delivered Mmbtu	0	52,351	111,542	84,426	7,360	0	0	0	0	0	0	0
Delivered $/Mmbtu	$4.951	$6.535	$7.930	$7.813	$6.736	$6.044	$6.111	$6.237	$6.378	$6.468	$6.515	$6.670
Delivered Cost	$0	$342,137	$884,572	$659,615	$49,578	$0	$0	$0	$0	$0	$0	$0
AECO TO TENNESSEE - ANE II												
Delivered Mmbtu	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000
Delivered $/Mmbtu	$4.166	$4.958	$5.511	$5.415	$5.070	$4.871	$4.800	$5.040	$4.849	$5.721	$5.620	$5.673
Delivered Cost	$124,988	$153,709	$170,836	$151,632	$157,185	$146,145	$148,810	$151,189	$150,327	$177,337	$168,597	$175,855

REDACTED

Total delivered to the City Gas Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	
NIAGARA TO TENNESSEE	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	
Delivered Mmbtu Niagara	24,000	31,000	31,000	28,000	31,000	30,000	12,521	5,000	0	0	0	31,000	
Delivered $/Mmbtu Niagara	$4.873	$5.731	$6.011	$6.053	$6.065	$6.001	$6.071	$6.180	$6.313	$6.402	$6.454	$6.603	
Total Delivered cosl	$116,963	$177,667	$186,349	$169,479	$188,030	$180,031	$76,013	$30,902	$0	$0	$0	$204,697	
TETCO TO B&W													
Delivered Mmbtu	12,432	35,076	37,296	31,080	12,846	0	0	0	0	0	0	0	
NYMEX $/Mmbtu Del	$5.254	$6.199	$6.529	$6.590	$6.584	$6.410	$6.475	$6.577	$6.701	$6.806	$6.890	$7.013	
Total Delivered cosl	$65,319	$217,434	$243,492	$204,802	$84,581	$0	$0	$0	$0	$0	$0	$0	
Dominion to Tetco FTS													
Delivered Mmbtu	0	1,590	3,710	3,710	0	0	0	0	0	0	0	0	
NYMEX $/Mmbtu Del	$4.637	$5.530	$5.801	$5.843	$5.858	$5.694	$5.760	$5.868	$5.995	$6.089	$6.155	$6.287	
Total Delivered cosl	$0	$8,793	$21,523	$21,679	$0	$0	$0	$0	$0	$0	$0	$0	
Dominion to Tetco FTS													
Delivered Mmbtu	0	31843	63550	52312	9730	0	0	0	0	0	0	0	
NYMEX $/Mmbtu Del	4.6372	5.5303	5.8013	5.8433	5.8577	5.6939	5.7598	5.8680	5.9948	6.0893	6.1545	6.2874	
Total Delivered cosl	$0	$176,101	$368,674	$305,673	$56,995	$0	$0	$0	$0	$0	$0	$0	
DISTRIGAS FCS													
Delivered Mmbtu	190,821	236,096	236,096	213,248	236,096	29,658	0	0	0	0	0	7,985	
Delivered $/Mmbtu	[redacted]												
Delivered Cost													
HUBLINE													
Delivered Mmbtu at Historical	0	47,085	103,540	73,148	4,931	240,000	248,000	201,297	94,938	89,413	134,728	248,000	
Delivered $/Mmbtu	$4.879	$6.664	$8.164	$8.106	$6.520	$5.890	$5.953	$6.074	$6.212	$6.300	$6.349	$6.496	
Delivered Historical	$0	$313,792	$845,288	$592,956	$32,151	$1,413,539	$1,476,391	$1,222,723	$589,777	$563,314	$855,406	$1,610,890	
	NOV	DEC	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	JUN	**JUL**	**AUG**	**SEP**	**OCT**	
Total Pipeline Costs	$12,976,378	$21,203,603	$24,887,798	$22,179,319	$19,609,830	$16,708,340	$11,180,264	$8,619,829	$8,324,307	$8,525,792	$8,621,438	$13,062,449	$175,899,348
Total Pipeline Volumes	2,905,207	3,887,492	4,166,226	3,699,560	3,407,598	2,898,913	1,916,430	1,462,457	1,388,566	1,393,465	1,387,284	2,043,573	30,556,771
WACOG	$4.467	$5.454	$5.974	$5.995	$5.755	$5.764	$5.834	$5.894	$5.995	$6.118	$6.215	$6.392	$5.756
Injections	0	0	0	0	0	535,068	539,392	516,749	554,841	527,139	478,409	433,194	3,584,792
Value at WACOG	$0	$0	$0	$0	$0	$3,083,948	$3,146,760	$3,045,757	$3,326,214	$3,225,253	$2,973,128	$2,768,961	$21,570,021
Pipeline Costs less Injections	$12,976,378	$21,203,603	$24,887,798	$22,179,319	$19,609,830	$13,624,392	$8,033,504	$5,574,073	$4,998,094	$5,300,539	$5,648,310	$10,293,488	$154,329,326
Pipeline Volumes less injections	2,905,207	3,887,492	4,166,226	3,699,560	3,407,598	2,363,845	1,377,038	945,708	833,725	866,326	908,875	1,610,379	26,971,979
NYMEX cost of Supplies	$12,512,727	$19,942,834	$22,589,277	$20,247,692	$18,649,784	$12,873,500	$7,586,102	$5,305,422	$4,777,244	$5,046,349	$5,358,727	$9,691,261	$144,580,919
Non-gas cost of delivered supplies													**$0.361**