STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

Winter 2009-10 Cost of Gas

DG 09-______

<u>Prefiled Testimony of Ann E. Leary</u>

August 31, 2009

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Q. Ms. Leary, please state your full name and business address.

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

Q. Please state your position with National Grid.

A. I am the Manager of Pricing-New England for the regulated gas companies including EnergyNorth Natural Gas, Inc. d/b/a National Grid NH.

Q. How long have you been employed by National Grid or its affiliates and in what capacities?

A. In 1985, I joined the Essex County Gas Company as Staff Engineer. In 1987, I became a planning analyst and later became the Manager of Rates. Following the acquisition of Essex by Eastern Enterprises in 1998, I became Manager of Rates for Boston Gas. After Eastern was acquired by KeySpan Corporation in November 2000, I continued on as Manager of Rates for the four KeySpan Energy Delivery New England regulated gas companies, Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas Company. My responsibilities remained the same following the acquisition of KeySpan by National Grid.

Q. What do your responsibilities as Manager of Pricing include?

A. As the Manager of Pricing, I am responsible for preparing and submitting various regulatory filings with both the New Hampshire Public Utilities Commission (the

"Commission") and the Massachusetts Department of Public Utilities on behalf of National Grid local gas distribution companies. This includes Cost of Gas ("COG") filings, Local Distribution Adjustment Charge ("LDAC") filings and reconciliations, energy conservation, performance-based revenue calculations, lost-base revenues, and exogenous cost filings.

Q. Please summarize your educational background.

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

Q. Have you previously testified in regulatory proceedings?

A. I have testified in a number of regulatory proceedings before the Commission and the Massachusetts Public Utilities on a variety of rate matters that include: cost allocation studies, rate design, cost of gas adjustment clause proposals, and exogenous cost filings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's proposed firm sales cost of gas rates for the 2009/10 Winter (Peak) Period to be effective beginning November 1, 2009.

COST OF GAS FACTOR

Q. What are the proposed firm sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.9663 per therm for residential customers, $0.9665 per therm for commercial/industrial high winter use customers and $0.9658 per therm for commercial/industrial low winter use customers as shown on Proposed Fourth Revised Page 87. The Company proposes a firm transportation cost of gas rate of ($0.0003) per therm as shown on Proposed First Revised Page 89.

Q. Would you please explain tariff page Proposed First Revised Page 86 and Proposed Fourth Revised Page 87?

A. Proposed First Revised Page 86 and Proposed Fourth Revised Page 87 contain the calculation of the 2009/10 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 87, the proposed 2009/2010 Average Cost of Gas of $0.9663 per therm is derived by adding the Direct Cost of Gas Rate of $0.9239 per therm to the Indirect Cost of Gas Rate of $0.0424 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $77,870,546. The estimated Indirect Cost of Gas, also derived on Page 86 and repeated on Page 87, is $3,573,460. The Direct Cost of Gas Rate of $0.9239 and the Indirect Cost of Gas Rate of $0.0424 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 84,282,098 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 86, total $(281,067). These adjustments are added to the Unadjusted Anticipated Cost of Gas of $78,151,613 to determine the Total Anticipated Direct Cost of Gas of $77,870,546.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed First Revised Page 86 consists of the following components:

1.	Purchased Gas Demand Costs	$6,919,850
2.	Purchased Gas Commodity Costs	$48,398,041
3.	Storage Demand and Capacity Costs	$1,097,023
4.	Storage Commodity Costs	$7,853,539
5.	Produced Gas Cost	$657,484
6.	Hedge Contract Loss/(Savings)	$11,627,343
7.	Hedge Underground Storage Loss/(Savings)	$1,868,333
	Total	$78,151,613

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed First Revised Page 86 are as follows:

1.	Prior Period Under Collection	$935,450
2.	Interest	49,971
3.	Broker Revenues	(890,609)

4.	Fuel Financing	210,305
5.	Transportation CGA Revenue	8,654
6.	Interruptible Sales Margin	(0)
7.	Capacity Release Margin	(635,528)
8.	Fixed Price Administrative Cost	40,691
	Total Adjustments	($281,067)

These allowable adjustments are standard accounting adjustments that are made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. Later in this testimony I will discuss the factors contributing to the prior period under collection.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in DG 08-106 for the 2008/2009 Winter Period?

The average cost of gas rate proposed in this filing is $0.2174 per therm lower than the initial rate of $1.1837 approved by the Commission in Order No. 24,909 dated October 29, 2008 in DG 08-106. This decrease in the rate reflects a decrease in the total cost of gas of approximately $27.4 million, or 25% (a $27.9 million decrease in total direct gas costs offset by a $0.5 million increase in indirect gas costs). The $27.9 million decrease in the total direct cost of gas is a result of a $25.8 million decrease in commodity costs, a $0.3 million increase in demand costs and a $2.4 million decrease in gas costs adjustments.

The $25.8 million decrease in commodity costs is due to a $15.4 million decrease in pipeline commodity costs, a $10.4 million decrease in supplemental costs (underground storage, LNG, and propane). The $15.4 million decrease in pipeline costs is due to a decrease in commodity costs of $16.8 million offset by a increase of $1.4 million resulting from increased pipeline throughput volumes. Total commodity gas costs (including hedges) are approximately $.22/therm lower than last year, resulting in a $16.8 million decrease which is offset by a increase in throughput of 1.6 million therms that causes a $1.3 million increase in gas costs. The two effects net out to the overall net decrease in commodity costs of $15.4 million.

The $10.4 million decrease in supplemental costs (underground storage, LNG, and propane) is due to a decrease in commodity costs of $3.4 million and a $7.0 million decrease resulting from decreased supplemental throughput volumes. The $2.4 million decrease in adjustments reflects a decrease in Prior Period Under Collection of $1.9 million. Small changes to interest, fuel financing, interruptible margins, and broker revenues make up the remaining $0.5 million variance.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2008/2009 winter period?

A. The proposed firm transportation winter cost of gas rate is ($0.0003) per therm. The rate approved in DG 08-106 was ($0.0001). This decrease is largely due to the decrease in peaking costs as compared to the 2008/09 period.

Q. What was the actual weighted average firm sales cost of gas rate for the 2008/2009 winter period?

A. The weighted average cost of gas rate was approximately $1.0888 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2008 through April 2009 to the monthly therm usage of a typical residential heating customer using 1,250 therms per year, or 932 therms for the six winter period months, for heat, hot water and cooking.

PRIOR PERIOD UNDER COLLECTION

Q. Please explain the prior period under collection of $659,570.

The prior period under collection is detailed in the 2008/2009 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $659,570 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2009 including Peak cost collections recovered in May 2009. The $659,570 under collection is reflected in Schedule 3, Tab 3 as the beginning balance for May 2009 before the addition of May direct gas costs (i.e., costs incurred in May that are related to the peak period) and adjustments. The under collection, which represents less than one percent of the total gas revenue billed, is the result of lower gas revenue billings than forecasted.

<u>FIXED PRICE OPTION</u>

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program ("FPO")?

A. Yes, in Order No. 24,515 in docket DG 05-127, dated September 16, 2005, the Commission approved an amendment to the Fixed Price Option Program. In accordance with the approved changes to the FPO program, the FPO rates are calculated at $0.02 per therm higher than the proposed COG filed on September 1 of each year. Proposed First Revised Page 88 contains the FPO rates for the 2009/10 Winter period, which are $0.9863 per therm for residential customers, $0.9858 per therm for commercial/industrial low winter use customers, and $0.9865 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2008/2009 winter period of $1.2835 per therm for residential customers, $1.2830 per therm for commercial/industrial low winter use customers, and $1.2836 per therm for commercial/industrial high winter use customers. This represents a $0.2972 per therm, or 23.2%, decrease in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a decrease of approximately $304 or 19.6% compared to last winter (please note - this total bill decrease includes the decrease in base distribution rates associated with the variance between the distribution rates approved in DG 08-009 effective July 1, 2009 and in rates further revised in DG 09-95 effective August 1, 2009 as compared to the temporary rate implemented on August 24, 2008 in Order No.24,888 in DG 08-009). The estimated winter period bill for a typical residential heating customer opting for the FPO program would be approximately $19 or 1.5% higher than the bill under the proposed cost of rates assuming that the COG is not revised prior to final approval by the Commission and also assuming no monthly adjustments to the COG rate during the course of the winter. Tab 23 contains the historical results of the FPO program as required by Order No. 24,515 issued on September 16, 2005 in DG05-127.

HEDGED SUPPLIES

Q. Has the Company hedged any of its winter period supplies pursuant to its proposed Natural Gas Price Risk Management Plan?

A. Yes, it has. As shown in Tab 7, Schedule 7, Page 2, the Company thus far has hedged 4,970,000 Dekatherms (49.7 million therms) at a weighted average fixed price of $7.7896 per Dekatherms. The hedged price reflects the high cost of gas during the period that the hedged volumes were locked in.

Q. On what dates and at what prices did the Company contract for these supplies?

A. The Company has fifty-seven contracts that hedge the price of gas supplies for the 2009/2010 Winter Period with prices ranging from $4.40 to $12.502 per Dekatherms. The contracts date as far back as May 2, 2008 and as recently as July 27, 2009. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

Under its Natural Gas Price Risk Management Plan, the Company expects to hedge approximately 67.5% of its flowing winter supplies that are priced against NYMEX price indexes (i.e. Dawn Supply, Niagara Supply, Tennessee Gas Pipeline direct purchases and Zone 4, and city gate deliveries). The projected flowing gas (i.e., pipeline) supplies amount to 7,945,289 Dekatherms. Currently, 65.4% of this total is projected to be hedged. The Company shows in Tab 7, Schedule 7, Page 3, that the remaining 228,000 Dekatherms will be hedged at an estimated price of $5.4460 per Dekatherms based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 5,198,000 Dekatherms at a cost of $39,956,183 or approximately $7.6868 per Dth.

OTHER ISSUES

Q. Has the Company reflected changes to its Indirect Gas Cost resulting from DG 08-009 and DG 07-072?

A. Yes, the Company has updated its Production and Storage Capacity Costs, Bad Debt Percentage, Miscellaneous Overhead and Working Capital calculation in accordance with the Settlement Agreement approved in DG 08-009 and the filed settlement agreement in DG 07-072. The hearing on the filed settlement in DG 07-072 is scheduled for September 8, 2009 and the Company anticipates an order prior to the effective date of the Winter Period COG rates.

Q. Has the Company changed the methodology of calculating the interest associated with its Peak Deferred Gas Cost Accounts (175.20, 175.52, and 142.20).

A. Yes, in accordance with the approved Settlement in DG 08-009, and the filed Settlement in DG 07-050, the Company will now include accrued (instead of billed) revenues when calculating the interest associated with its deferred gas costs accounts. The hearing on the filed settlement in DG 07-050 is scheduled for September 8, 2009 and the Company anticipates an order prior to the effective date of the Winter Period COG rates.

<u>LOCAL DISTRIBUTION ADJUSTMENT CHARGE</u>

Q. What are the surcharges that will be billed under the LDAC?

A. The Company is submitting for approval a Local Distribution Adjustment Charge of $0.0410 for the residential non heating class, $0.0404 for the residential heating class and $0.0194 for the commercial/industrial classes that will be billed from November 1, 2009 through October 31, 2010. Under the LDAC approved in (1) the Commission's Order in Docket DG 00-063, the Company's Revenue Neutral Rate Redesign Case, (2) Order No. 24,109 in DG 02-106, Energy Efficiency for Gas Utilities, (3) Order No. 24,636 in DG 06-032, Energy Efficiency for Gas Utilities, (4) Order No. 24,508 in DG 05-076, Investigation of Low Income Assistance Program for Natural Gas, (5) Order No. 24,690 in DG 06-107, the Company's Petition for Approval of Merger Transaction, and (6) Order No. 24,972 in DG 08-009, the Company's Delivery Rate Increase Case, the surcharges that are billed under the LDAC are the Conservation Charge, the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant remediation, the Residential Low Income Assistance Program charge, the Emergency Response Incentive charge, and the Rate Case expense netted against the true up of the Temporary versus Final Rates approved in DG 08-009.

Q. What is the Conservation Charge?

A. The Conservation Charge is designed to recover the expenses and lost margins from the Company's demand side management ("DSM") programs that terminated in 1999. With the implementation of new base rates effective August 24, 2008, the collection of Lost Margins associated with programs terminated in 1999 is now eliminated. The ($0.0006) credit represents an over collection in 2008/09.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover expenses associated with the Company's energy efficiency programs that were approved by the Commission in Order No. 24,995 dated July 31, 2009, in DG 09-049. On March 12, 2009, the Company submitted to the Commission its proposed energy efficiency budget for May 2009 through December 2010. The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs that were approved by the Commission in Order 24,109 dated December 31, 2002 in DG 02-106 and Order 24,636 dated June 8, 2006 in DG 06-032. The incentive calculations that are included in this LDAC filing are based on Exhibit C. Exhibit C, the incentive calculation, is provided in Tab 19, Energy Efficiency, page 5.

Q. In Order No. 24,752 in docket DG 06-154 relating to therm billing issues, the Company agreed to exclude $200,000 in cost recovery associated with energy

efficiency expenditures in Program Years 2 and 3. Did the Company reflect these adjustments in its Energy Efficiency Charge?

A. Yes, in March and April 2008, the Company included a credit of $122,165 in DSM measures. The Company spent the remaining $77,835 during the 2008-09 program year and applied the balance of the credit in March 2009.

Q. What is the proposed Residential Low Income Assistance Program, RLIAP, charge?

A. The proposed Residential Low Income Assistance Program charge is $0.0099. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this charge. For the 2009/10 Winter Period the Company is providing a 60% base rate discount, consistent with the Settlement agreement approved by the Commission in Order No. 24,669 issued on September 22, 2006 in DG 06-120. The current RLIAP factor is designed to recover $1,491,674 of which $1,497,827 is for the revenue shortfall resulting from 6,466 customers receiving a 60% discount off their base rates, $8,600 is for estimated administrative costs, and ($14,753) is for the prior year reconciling adjustment.

Q. In Order No. 24,824 in docket DG 06-122 relating to short term debt issues, the Company agreed to adjust its short term debt limits each year as part of the Company's Winter Period cost of gas filing. Did the Company calculate the short term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Tab 24 the short term debt limit for fuel and non fuel purposes for the 2008-09 period. As shown, the short term limit for fuel inventory financing for the period November 1, 2009 through October 31, 2010 will be $24,433,202 and the limit for non-fuel purposes will be $51,621,000.

Q. Have these new limits been communicated to the Company's Treasury Group?

A. Yes.

Q. Has the Company updated the Manufactured Gas Plant Remediation surcharge (Tariff Page 91)?

A. Yes, it has. As a result, of the Company's success in its third party cost recovery efforts, which included receiving a significant insurance recovery last year, the total recoveries from insurance carriers and other responsible parties continue to exceed the total remediation costs expensed to date. As a result, the Company proposes that the Manufactured Gas Plant (MGP) Remediation surcharge is proposed to remain at zero for the period beginning November 1, 2009 and ending October 31, 2010. The surcharge for the 2007/2008 Winter Period and 2008/2009 Winter Period was also $0.0000 per therm. The costs submitted for recovery through the MGP Remediation surcharge as well as the third party recoveries are presented in the Environmental Cost Summary included in Tab 20 of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Leone in her prefiled testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Tab 20. The Summary included in Tab 20, pages 1 – 7, show the remediation cost pools for the Concord, Manchester, Nashua, Dover, Laconia and Keene sites and a General Pool for costs that cannot be directly assigned to a specific site. The filing also includes amounts recovered from insurance companies shown in the section labeled "Cash Recoveries" on the Environmental Cost Summary, pages 8 - 10. These cash recoveries from insurance companies are listed under the headings for the Concord, Laconia, Manchester, Nashua, Dover, and Keene sites. While the recoveries are displayed on the summary by site, they are not exclusive to a particular site. Because the recoveries are often the result of a general settlement agreement between National Grid, NH and an insurance company covering more than one site, there is usually no distinction made as to how much of the settlement amount is associated with a particular site. The reason the recoveries are presented on the summary in this way is to reflect how the Company is recording them in its accounting records. In compliance with Commission Order No. 23,303, dated September 20, 1999 in docket DG 99-060, the Company is crediting the third-party recoveries, net of expenses associated with those recoveries, to the end of the recovery period with the exception of those recoveries from prior plant operators that are contributions to the on-going expense of site investigation and remediation. Those amounts are netted out against the Company's expenses before any remaining balance is included for recovery through the MGP Remediation surcharge. Page 11 provides the total remediation and recovery costs and collections by year and in total.

As I have noted, due to the significant third party cash recovery received last year the Company is not proposing an Environmental surcharge for the 2009-10 period. The Company's filing, however, does summarize its total remediation, recoveries and surcharge collections incurred to date so that the Commission is aware of the current ending balance. In total, the Company has incurred environmental remediation costs of $27,379,667 litigation costs of $7,178,376, obtained third party cash recoveries of $22,792,408, for a net expense of $11,765,635. To date, the Company has collected $13,041,861 from its Environmental Surcharge factor. As a result, of the third party cash recoveries received last year, the total recoveries from insurance carriers and other responsible parties currently exceed the total remediation costs by $1,276,226. The Company proposes to apply this credit of $1,276,226 to future remediation and recovery costs. This $1,276,226 over recovery includes an interest credit of $248,524, which represents 80% of interest associated with the environmental over recoveries, as approved in Order No. 24,881 in docket DG 07-129. This interest has been included as a credit to the General Expense account.

The 2008-2009 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #10)	$115,579
Concord (Pool #6)	$92,679
Laconia (Pool #8)	$624,557
Manchester (Pool #9)	$312,185

Nashua (Pool #9)	$16,289
Keene (Pool #6)	$269
General (Pool #7)	($2,931)
Total Remediation	$1,158,627
Litigation Recovery	($2,101,312)
Litigation Costs	9,795
Total 2008-09	($932,890)

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2008-09 costs that the Company is submitting for recovery. (Copies of the relevant invoices are being provided under a separate cover to the Commission auditing staff concurrently with this filing.) Consistent with past practice, the Company met with the staff and Consumer Advocate's office earlier this year to update them on the status of environmental matters. While the Company has provided in Tab 20 of this filing written summaries of the status of each MGP site, it is prepared to provide additional testimony and exhibits, as necessary, to support recovery of these amounts if the Commission Staff believes that it is necessary after it has completed its review of these costs. In addition, the Company is providing more detailed testimony from Ms. Leone to discuss the Company's efforts to seek recovery of its environmental costs from relevant third parties.

Q. In Order No. 24,849 in docket DG 07-129, the Commission ordered the Company to apply 80 percent of the interest earned from the over recovery of environmental response costs to future remediation costs. Has the Company reflected these interest credits in this filing?

A. Yes, as I noted above, the Company has calculated the customers' portion of the interest credit associated with the over recovery of environmental costs and has included these credits in the "General Expense" category. The Company has included $32,768 credits in this account for 2008-09 period.

Q. Does the LDAC include a surcharge for Interruptible Transportation Margins?

A. The Company is proposing no surcharge for Interruptible Transportation Margins because it has not provided any service under the classification over the past year and therefore has not earned any margins for this surcharge.

Q. Does the LDAC include a credit associated with the Rate Case expense and True up of Temporary versus Final Rates approved in DG 08-009?

A. Yes, in accordance with the Settlement Agreement approved in DG 08-009, the Company netted rate case expense of $802,365 against the Temporary vs. Final Rate over collection of $3,740,913 for a net credit of $2,938,277. This will result in a credit of $0.0195/therm which will be refunded to customers from November 2009 through October 2010.

Q. Does the LDAC include the recovery of the Emergency Response incentive approved in the EnergyNorth/National Grid Merger in DG 06-107?

A. Yes, as part of the Settlement Agreement approved in DG 06-107, the Company had the ability to earn a $600,000 incentive if it was able to meet certain specified emergency response times over the period September 2007-December 2008. Schedule 19 documents the Company's emergency response time rates and demonstrates that the Company has met the time specifications agreed to in that Settlement. Accordingly, the Company has included a one time incentive of $600,000 in its LDAF filing in accordance with the Section (N) part (2) of the Settlement Agreement in docket DG 06-107.

CUSTOMER BILL IMPACTS

Q. What is the estimated impact of the proposed firm sales cost of gas rate and revised LDAC surcharges on an average heating customer's seasonal bill as compared to the rates in effect last year?

A. The bill impact analysis is presented in Tab 8, Schedule 8 of this filing. Please note that these bill impacts include the decrease resulting from the implementation of the final base distribution rates approved in Order No. 24,972 in docket DG 08-009. The approved base Rates represent a decrease as compared to the temporary base distribution rates approved in Order No. 24,888 also in docket DG 08-009. The total bill impact for a typical residential heating customer is an decrease of approximately $142, or 10.3% of which $101 or 7.3% is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2008/2009 winter season, and $41 or 3.0% is from the decrease resulting from the implementation of approved base rates in DG 08-009. The total bill impact for a typical commercial/industrial G-41 customer is an decrease of approximately $244, or 11.1% of which $197 or 9.0% is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2008/2009 winter season, and $47 or 2.1% is from the decrease resulting from the implementation of approved base rates in DG 08-009. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed First Revised Page 155 relating to Supplier Balancing Charges and Proposed First Revised Page 156 relating to Capacity Allocation.

Q. Please describe the changes to Page 155.

A. In Proposed First Revised Page 155, the Company is updating the Peaking Demand Charge from $10.02 per MMBtu of Peak MDQ to $16.43 per MMBtu of Peak MDQ, a $6.41 increase.

The increase in the Peaking Demand Charge is a result of the classification of 25,000 MMBTU per day on the Concord Lateral as Peaking supply. This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions First Revised Page 155, Attachment B – Peaking Demand Charge.

Q. Please describe the changes to Page 156.

A. Proposed First Revised Page 156 updates the Capacity Allocator percentages used to allocate pipeline, storage and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Tab 22 contains the six-page worksheet that backs up the calculations for the updated allocators.

Q. Does this conclude your testimony?

A. Yes, it does.

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EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

Winter 2009/2010 Cost of Gas
DG 09-______

Prefiled Testimony of Theodore Poe, Jr.

September 1, 2009

Q. Mr. Poe, please state your name, address and position with National Grid New Hampshire.

A. My name is Theodore Poe, Jr. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451. My title is Lead Analyst.

Q. Mr. Poe, please summarize your educational background, and your business and professional experience.

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science Degree in Geology. From 1981 to 1989, I worked as a Research Associate with Jensen Associates, Inc. of Boston where I was responsible for the development of a variety of computer forecasting models of natural gas supply and demand for interstate pipeline and local distribution companies. In 1989, when I joined Boston Gas Company, I was responsible for modeling and forecasting the natural gas resource requirements of its customers. Since 1998, I have assumed the added responsibilities of forecasting the natural gas requirements of various service territories that are now part of National Grid, including EnergyNorth Natural Gas, Inc., which does business under the name National Grid NH.

Q. Mr. Poe, are you a member of any professional organizations?

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

Q. Mr. Poe, have you previously testified in regulatory proceedings?

A. Yes, I have testified in a number of proceedings before the Commonwealth of Massachusetts Department of Public Utilities and the State of New Hampshire Public Utilities Commission.

Q. Mr. Poe, what is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to summarize the gas supply and transportation portfolio and the forecasted sendout requirements for National Grid NH (the "Company") for the 2009/10 peak season. This information is provided in significantly more detail in the schedules that the Company is filing.

Q. Mr. Poe, would you describe the transportation contract portfolio that the Company now holds?

A. The Company currently holds contracts on Tennessee Gas Pipeline (76,833 MMBtu/day) and Portland Natural Gas Transmission (1,000 MMBtu/day) to provide a daily deliverability of 77,833 MMBtu/day to its city gate stations. Schedule 12, page 1 in the Company's filing is a schematic diagram of these contracts, and Schedule 12, page 2 is a table listing these contracts. These contracts provide delivery of natural gas from three sources.

First, the Company holds contracts to allow for delivery of up to 8,122 MMBtu/day of Canadian supply. These consist of the following:

- The Company can receive up to 4,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held transportation contracts on Union Gas, TransCanada, Iroquois Gas Transmission System, and Tennessee Gas Pipeline.
- The Company can receive up to 3,122 MMBtu/day of firm Canadian supply from the Canadian/New York border at Niagara Falls, NY. This supply is transported on Company-held transportation contracts on Tennessee Gas Pipeline for delivery.
- The Company can receive up to 1,000 MMBtu/day of firm Canadian supply from a Company-held transportation contract on Portland Natural Gas Transmission for delivery to its Berlin division.

Second, the Company holds the following contracts to allow for delivery of up to 41,596 MMBtu/day of domestic supply from the producing and market areas within the United States.

- The Company can receive up to 21,596 MMBtu/day of firm domestic supplies from Texas and Louisiana production areas. These supplies are delivered to the Company on transportation contracts on Tennessee Gas Pipeline.

- The Company can receive up to 20,000 MMBtu/day of firm supply from Tennessee's Dracut delivery point located in Dracut, Massachusetts. This supply is delivered to the Company on a transportation contract on Tennessee Gas Pipeline.

Third, the Company holds the following contracts to allow for delivery of up to 28,115 MMBtu/day of domestic supply from underground storage fields in the New York/Pennsylvania area or the purchase of flowing supply in or downstream of Tennessee Zones 4 and 5.

- The Company can receive up to 19,076 MMBtu/day of firm domestic supplies from its Tennessee Gas Pipeline FS-MA storage contract. This contract allows for a storage capacity of 1,560,391 MMBtu. These supplies are delivered to the Company on a transportation contract on Tennessee Gas Pipeline.
- The Company can receive up to 9,039 MMBtu/day of firm domestic supplies from its storage contracts with National Fuel Gas, Honeoye and Dominion. In aggregate, these contracts allow for a storage capacity of 1,019,740 MMBtu. These supplies are delivered to the Company on a transportation contract on Tennessee Gas Pipeline.

Q. Have there been any changes in the portfolio of transportation contracts that the Company now holds since the Company submitted its 2008/09 Peak Period Cost Of Gas Filing?

A. There will be one, effective November 1st, 2009. On that date, the Company expects to begin utilization of its additional 30,000 MMBtu/day of Tennessee capacity from the Concord Lateral Project from Dracut, MA to the Company's citygates. This contract was discussed in Docket DG 07-101 and approved by the Commission in Order No. 24,825.

Q. Would you describe the source of gas supplies used with these transportation contracts?

A. The transportation contracts associated with the Canadian supplies receive firm supplies from both Eastern and Western Canada. The supplies associated with the Company's domestic long-haul transportation contracts are firm supplies that the Company purchases primarily in the U.S. Gulf Coast. Supplies purchased at the Dracut, MA receipt point can originate from any of a number of locations including Canada, the U.S. Gulf Coast, and LNG terminals.

Q. Have there been any changes in the portfolio of supply contracts that the Company now holds since the Company submitted its 2008/09 Peak Period Cost Of Gas Filing?

A. Yes. Typically, the Company negotiates a number of different supply contracts for delivery during the peak period. Since its 2008/09 Peak Period filing, the Company has issued or participated in requests for proposals ("RFP") for the upcoming winter for the following supply resources:

1. Underground storage refill arrangement;

2. Supply for its Tennessee long-haul transportation capacity; and,
3. Supply for its transportation capacity from Dawn, Ontario

On April 3, 2009, the Company issued an RFP for off-peak period refill of its underground storage fields. Bid responses were received by the Company on April 15, 2009, to be effective May 1, 2009. The Company awarded the bid to fill its underground fields to Sempra Energy Trading LLC ("Sempra"). Sempra submitted the best overall bid, based on both price and non-price factors. The contract provides for a six-month ratable storage refill plan. The price for this supply is index based. The indices correlate to the respective receipt points on the Company's long-haul transportation contract.

The objective of the summer refill program is to purchase supply as ratably as possible throughout the May through October off-peak period. The Company plans to have all storage fields, with the exception of its Tennessee FS-MA storage, 100 percent full by 1 November 2009; the Tennessee FS-MA field is targeted to be 95 percent full by 1 November 2009. The 5 percent unfilled portion of FS-MA storage provides a buffer which allows the Company operational flexibility to inject some of its Tennessee long-haul supply into storage if needed due to weather fluctuations during the month of November. By 1 December 2009, it is the Company's plan to have all of its storage fields 100 percent full.

On July 1, 2009, the Company issued an RFP for peak-period supply for its Tennessee long-haul transportation capacity. Bid responses were received by the Company on July 14, 2009, to be effective November 1, 2009. The Company awarded the bid to Chevron Natural Gas ("Chevron"). Chevron submitted the best overall bid, based on both price and non-price factors. The contract provides for a six-month supply with both baseload and swing nomination provisions. The price for this supply is index based. The indices correlate to the respective receipt points on the Company's long-haul transportation contract.

On July 31, 2009, as a member of the Northeast Gas Markets consortium of LDCs, the Company participated in an RFP for peak-period supply for its transportation capacity from Dawn, Ontario. Bid responses were received by the Company on August 14, 2009, to be effective November 1, 2009. As a result of this RFP, the Company will purchase these volumes during the November 2009 – March 2010 period from BP Canada Energy Company who submitted the best overall bid based on both price and non-price factors. These are baseload volumes with NYMEX-based pricing. This arrangement also designates BP Canada as manager for the Canadian portion of the transportation path from November 2009 through October 2010. In return, the customers will receive a guaranteed payment from BP Canada which will be credited back on a monthly basis.

On 1 April 2007, the Company began receiving gas supplies from BP Canada Energy Marketing Corp. for its Tennessee Niagara capacity. I previously described this contract in my 2007 Off-Peak Period Cost of Gas Testimony. The contract allows for monthly nominating flexibility, with an index-based price.

For all of its Tennessee Dracut capacity, including 30,000 MMBtu/day of the Concord Lateral Project, the Company is currently finalizing its RFP for peak period supply.

For its Portland Natural Gas Transmission capacity, the Company continues to contract on a month-to-month basis for supplies, purchased at the Company's primary receipt point designated as Pittsburg, NH, and delivered to its citygate station in Berlin, NH.

Q. Would you describe the additional sources of gas supply available to the Company that do not require pipeline transportation capacity?

A. The Company has three additional sources of gas supply available to it.

First, the Company, along with its Massachusetts affiliates Boston Gas Company, Colonial Gas Company and Essex Gas Company each d/b/a National Grid, is a party to a contract with Distrigas for up to 1 Bcf of liquid-only supply that can be used to refill any of the National Grid LNG storage tanks in New England, including those serving New Hampshire.

Second, the Company holds a supply-sharing agreement with Granite Ridge Energy, LLC to provide up to 15,000 MMBtu/day and 450,000 MMBtu per contract year. The pricing terms of this contract were previously disclosed to the Commission, and they will not be discussed here because of their confidential nature. This contract is only available to the Company during the December through February period of each contract year. The agreement requires the parties to negotiate the pricing formula prior to the start of each contract year. The Company is currently in negotiations regarding the price to be paid for this supply for this upcoming winter season. In the event that the parties are unable to reach agreement the price defaults to an index based formula tied to the price of electricity.

Finally, when supplies are available and when it is cost-effective, the Company can obtain supplies from other supply vendors. The natural gas market within the Northeast United States has evolved to the point that firm supplies, deliverable to the Company's city gate stations, are available on most days throughout the year.

Q. Please describe the supplemental gas supply facilities available to the Company?

A. The Company owns three LNG vaporization facilities in Concord, Manchester and Tilton that have a combined operational vaporization rate of 23,712 MMBtu/day and a combined workable storage capacity of 13,057 MMBtu. Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua and Tilton that have a combined operational vaporization rate of 35,000 MMBtu/day and a combined workable storage capacity of 100,993 MMBtu.

The Company's LNG facilities are refilled with liquid from Distrigas using the 1 Bcf Firm Liquid Contract to which all of the National Grid New England companies are a party. During the 2009 off-peak period, the Company offset boiloff losses by periodically trucking LNG liquid to its facilities. The Company is currently in the process of issuing an RFP for its dedicated LNG trucking requirements for the peak period.

Following the 2008/09 peak period, the Company's propane facilities were full and they remain ready for the 2009/10 peak period. Additionally, the Company currently has approximately 464,000 gallons of propane stored at the National Grid propane facilities in Massachusetts on behalf of National Grid NH. . The Company is currently reviewing the need for winter propane transportation needs for the upcoming peak period.

Q. Mr. Poe, what was the source of the projected sendout requirements and costs used in this filing?

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

Q. Would you please describe the forecasted sendout requirements for the peak period of 2009/10?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers of 86,404,722 therms over the period November 1, 2009 through April 30, 2010 under normal weather conditions, down 9.4 percent from last year's value of 95,368,818 therms. Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 94,562,239 therms over the period November 1, 2009 through April 30, 2010 under design weather conditions, down 9.1 percent from last year's value of 103,985,815 therms. This shows that design weather requirements are 9.4 percent greater than normal sendout requirements for weather that is 8.5 percent colder than normal. In Schedule 11C, the Company summarizes the normal and design year sendout requirements, the seasonally-available contract quantities, and the utilization rates of its pipeline transportation and storage contracts. Schedule 11D shows the Company's forecasted design day sendout for sales customers for the upcoming 2009/10 winter of 1,222,692 therms, down 6.4 percent from last year's figure of 1,306,916 therms.

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

A. Yes, it does.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Re: EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

Winter 2009-2010 Cost of Gas

Docket No. DG 09-_______

Pre-filed Direct Testimony of
Michele V. Leone
on behalf of
EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

August 31, 2009

I. BACKGROUND

Q. Please provide your name, job title and job description.

A. My name is Michele Leone. I am the Manager of the New England Site Investigation and Remediation Program for National Grid, through which I provide services to EnergyNorth Natural Gas, Inc. d/b/a National Grid NH (”National Grid NH” or the “Company”.) I am responsible for overseeing the management of the investigation and remediation of MGP sites for National Grid NH as well as for the Company's Massachusetts and Rhode Island affiliates.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science in Environmental Engineering from Syracuse University, and a Master of Science in Engineering in Environmental Engineering from the University of Michigan at Ann Arbor. I have been employed by National Grid since December 2000 in the Site Investigation and Remediation Group, managing the investigation and remediation of MGP sites. Prior to my employment by National Grid, I held the position of Project Manager for an environmental consulting firm, with responsibility for the investigation and remediation of numerous hazardous waste sites and for providing technical support to expert witnesses in litigation cases.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the status of site investigation and remediation efforts at various MGP sites in New Hampshire, to briefly describe the MGP-related activities performed by the various contractors and consultants the costs for which National Grid NH is seeking rate recovery, and to describe the efforts that National Grid NH has made to seek reimbursement for MGP related liabilities from third parties in order to diminish the costs submitted for recovery from the Company's customers. My testimony is intended to update the information provided by the Company in prior cost of gas proceedings. The costs associated with these investigations and remediation efforts and certain of the amounts recovered from third parties are included in the schedules and other data prepared by Ms. Leary as part of the Company's cost of gas filing.

STATUS OF INVESTIGATION AND REMEDIATION ACTIVITIES

Q. Will you please briefly describe the status of each of the Company's MGP sites?

A. Rather than reviewing each of these sites in a question and answer format, consistent with past practice, the description of the status of investigation and remediation efforts at each site as well as the various efforts to recover the site investigation and remediation costs from third parties are summarized in materials included with Tab 20 of the Company's filing. These summaries follow the format that has previously been agreed upon in discussions between the Company and Commission staff. In addition, as previously ordered by the Commission, on August 3, 2009, the Company held what has become an annual technical session with the Commission staff (as well as the Consumer Advocate) to keep the Commission apprised of the status of site investigation and remediation efforts, as well as cost recovery efforts against third parties.

Q. In 2004, the Company began an investigation of a disposal area associated with the Laconia MGP. Please briefly describe the current status of the Company's investigation and any significant events over the course of the past year.

A. The disposal area, known as Lower Liberty Hill, is located in what is now a residential neighborhood in Gilford. The Company completed investigation activities at Lower Liberty Hill in 2007 and the results indicate that soil and groundwater contamination from MGP waste products have impacted locations formerly occupied by four residential properties and a portion of an abutting stream. These impacts are primarily located in sub-surface soils, and in deep groundwater. No drinking water impacts have been found. A Remedial Action Plan ("RAP") was submitted to NHDES in February 2007, which recommended a remedial alternative consisting of a subsurface containment wall, limited soil removal and an impermeable cap. In September 2007, NHDES, responded to the February 2007 RAP and required the Company to evaluate additional remedial alternatives that included further soil removal. In November 2007, the Company submitted RAP Addendum No. 1 to NHDES. The revised plan recommended a remedial alternative that included construction of a subsurface containment wall, removal of tar-saturated soils to a depth of approximately 45 feet, and installation of an impermeable cap on the four residential properties owned by the Company. On February 29, 2008, NHDES issued a letter to the Company indicating that it had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period. Following a public meeting in March and a six week public comment period, NHDES issued a letter on June 26, 2008, deferring its final decision on the recommended remedial alternative for the Lower Liberty Hill site pending further data analysis following the development of a scope of work prepared after consultations between NHDES, the Town of Gilford and National Grid NH . In July and August 2008, technical representatives from National Grid NH , the Town of Gilford, a Liberty Hill resident and NHDES met to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. Field activities were completed between November 2008 and January 2009. Modeling efforts were completed in May 2009. During the performance of this work, National Grid NH met with technical representatives from the Town of Gilford, a Liberty Hill resident and NHDES to provide an update and discuss the work. Modeling results indicate that low-flow pumping would need to be added to the selected remedy to meet the remedial goals for this site. On June 30, 2009, NHDES requested that a second RAP addendum be prepared for the site to evaluate the technical changes resulting from the modeling effort . The RAP Addendum No. 2 was submitted to NHDES on August 17, 2009. A public meeting is scheduled for September 10, 2009.

ENGI has also performed numerous other activities requested by NHDES in 2008 and 2009, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan; evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; and semi-annual groundwater and surface water sampling activities. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

Q. Please briefly describe the current status of the Company's remediation work at the Manchester MGP.

A. A Remedial Action Plan is being developed for the upland portion of the MGP site and is currently scheduled for submittal to NHDES by June 30, 2010. Pre-design investigations are ongoing on the upland portion of the former MGP site in 2008/2009. In addition, ENGI is currently conducting interim remediation activities at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale coal tar recovery, and design for replacement of a portion of the site drainage system. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedences in shallow soils. In addition, ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements.

Q. Please briefly describe the current status of the Company's remediation work at the Concord MGP.

A. The activities at the Concord MGP distinguished by two areas: the Concord MGP site an the Exit 13 pond.

The Company began investigation activities at the Concord MGP site in late 2004. Following initial investigation activities, NHDES requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. Supplemental scopes of work were submitted to NHDES in 2005 and 2007. In June 2008, the Company bid the 2007 NHDES-approved scope of and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report is currently being finalized. ENGI will meet with NHDES to discuss the report findings and strategy for moving forward when the final report is submitted to NHDES.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested that the Company address the residual contamination in the pond, and in response, the Company submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented and the results of the additional work were to be used to develop a conceptual design for addressing the residual contamination. An Interim Data Collection Report was submitted to NHDES in September 2006, and a Conceptual Remedial Design in March 2007.

On March 25, 2009, National Grid NH submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a Remedial Action Plan. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project has moved into the remedial design phase.

During May 19, 2009 through May 22, 2009, National Grid NH implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. The sediment sampling data report summarizing the results of the investigation is currently being drafted. ENGI will meet with NHDES to discuss the report findings and strategy for moving forward when the final report is submitted to NHDES.

Q. Please briefly describe the current status of the Company's remediation work at the Nashua MGP.

A. In June 2008, the Company installed six extraction wells for coal tar recovery pilot testing at the site. National Grid NH completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual coal tar recovery throughout 2008 and 2009. In Spring 2009, ENGI began trenching and final system installation activities. The trenching, pump installations and system electrical work was completed in

July 2009. System start-up is pending final electrical hook-up by PSNH. It is anticipated that this work will be completed in August 2009.

Q. What other MGP investigation and remediation activity has the Company undertaken in the last year?

A. Lower Liberty Hill, Manchester, Concord and Nashua are the four sites where there is significant activity involving the Company. There is little or no activity to report at the Keene or Dover locations at this time. As I mentioned previously, the summaries included in the Company's cost of gas filing provide additional detail regarding all of the Company's former MGP sites.

III STATUS OF INSURANCE COVERAGE LITIGATION

Q. Have there been any recent significant developments in the Company's efforts to seek contribution from its insurance carriers that you wish to discuss?

A. No. Insurance recovery efforts are mostly complete with respect to all of the Company’s former MGP sites. With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated. .

Q. Does this conclude your direct testimony?

A. Yes, it does.

ENERGY NORTH NATURAL GAS, INC,
d/b/a KeySpan Energy Delivery N.E.
Peak 2009 – 2010 Winter Cost of Gas Filing

Filed Tariff Sheets

Proposed Fifth Revised Page 1
Check Sheet

Proposed Fifth Revised Page 3
Check Sheet

Proposed First Revised Page 5
Check Sheet

Proposed Fifth Revised Page 76
Firm Rate Schedules

Proposed First Revised Page 86
Anticipated Cost of Gas

Proposed Fourth Revised Page 87
Calculation of Firm Sales Cost of Gas Rate

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Calculation of Firm Sales Cost of Gas Rate

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Calculation of Firm Transportation Cost of Gas Rate

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Environmental Surcharge - Manufactured Gas Plants

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Rate Case Expense

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Local Distribution Adjustment Charge Calculation (LDAC)

Proposed First Revised Page 155
Attachment B - Schedule of Administrative Fees and Charges

Proposed First Revised Page 156
Attachment C - Capacity Allocators

CHECK SHEET

The title page and pages 1-91 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

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II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 9.77			$ 9.77	$ 9.77			$ 9.77
All therms	$ 0.1507	$ 0.9663	$ 0.0410	$ 1.1580	$ 0.1507	$ 0.5866	$ 0.0254	$ 0.7627
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 14.03			$ 14.03	$ 14.03			$ 14.03
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2467	$ 0.9663	$ 0.0404	$ 1.2534	$ 0.2467	$ 0.5866	$ 0.0260	$ 0.8593
All therms over the first block per month at	$ 0.1859	$ 0.9663	$ 0.0404	$ 1.1926	$ 0.1859	$ 0.5866	$ 0.0260	$ 0.7985
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 5.61			$ 5.61	$ 5.61			$ 5.61
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.0987	$ 0.9663	$ 0.0404	$ 1.1054	$ 0.0987	$ 0.5866	$ 0.0260	$ 0.7113
All therms over the first block per month at	$ 0.0744	$ 0.9663	$ 0.0404	$ 1.0811	$ 0.0744	$ 0.5866	$ 0.0260	$ 0.6870
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$ 35.08			$ 35.08	$ 35.08			$ 35.08
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2974	$ 0.9665	$ 0.0194	$ 1.2833	$ 0.2974	$ 0.5871	$ 0.0278	$ 0.9123
All therms over the first block per month at	$ 0.1934	$ 0.9665	$ 0.0194	$ 1.1793	$ 0.1934	$ 0.5871	$ 0.0278	$ 0.8083
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$ 100.24			$ 100.24	$ 100.24			$ 100.24
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.2642	$ 0.9665	$ 0.0194	$ 1.2501	$ 0.2642	$ 0.5871	$ 0.0278	$ 0.8791
All therms over the first block per month at	$ 0.1745	$ 0.9665	$ 0.0194	$ 1.1604	$ 0.1745	$ 0.5871	$ 0.0278	$ 0.7894
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$ 421.01			$ 421.01	$ 421.01			$ 421.01
All therms over the first block per month at	$ 0.1591	$ 0.9665	$ 0.0194	$ 1.1450	$ 0.0728	$ 0.5871	$ 0.0278	$ 0.6877
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$ 35.08			$ 35.08	$ 35.08			$ 35.08
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.1928	$ 0.9658	$ 0.0194	$ 1.1780	$ 0.1928	$ 0.5851	$ 0.0278	$ 0.8057
All therms over the first block per month at	$ 0.1245	$ 0.9658	$ 0.0194	$ 1.1097	$ 0.1245	$ 0.5851	$ 0.0278	$ 0.7374
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$ 100.24			$ 100.24	$ 100.24			$ 100.24
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.1505	$ 0.9658	$ 0.0194	$ 1.1357	$ 0.1106	$ 0.5851	$ 0.0278	$ 0.7235
All therms over the first block per month at	$ 0.1021	$ 0.9658	$ 0.0194	$ 1.0873	$ 0.0637	$ 0.5851	$ 0.0278	$ 0.6766
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$ 431.03			$ 431.03	$ 431.03			$ 431.03
All therms over the first block per month at	$ 0.1087	$ 0.9658	$ 0.0194	$ 1.0939	$ 0.0520	$ 0.5851	$ 0.0278	$ 0.6649
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$ 431.03			$ 431.03	$ 431.03			$ 431.03
All therms over the first block per month at	$ 0.0355	$ 0.9658	$ 0.0194	$ 1.0207	$ 0.0192	$ 0.5851	$ 0.0278	$ 0.6321

Anticipated Cost of Gas

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 6,919,850	
Supply Costs:	48,398,041	
Storage Gas:		
Demand, Capacity:	$ 1,097,023	
Commodity Costs:	7,583,539	
Produced Gas:	657,484	
Hedged Contract Savings	11,627,343	
Hedge Underground Storage Contract (Savings)/Loss	1,868,333	
Unadjusted Anticipated Cost of Gas		$ 78,151,613
Adjustments:		
Prior Period (Over)/Under Recovery (as of 10/31/09)	$ 935,450	
Interest	49,971	
Prior Period Adjustments	-	
Broker Revenues	(890,609)	
Refunds from Suppliers	-	
Fuel Financing	210,305	
Transportation CGA Revenues	8,654	
Interruptible Sales Margin	-	
Capacity Release and Off System Sales Margins	(635,528)	
Hedging Costs	-	
Fixed Price Option Administrative Costs	40,691	
Total Adjustments		(281,067)
Total Anticipated Direct Cost of Gas		$ 77,870,546
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Anticipated Direct Cost of Gas 11/01/09 - 04/30/10)	$ 78,151,613	
Lead Lag Days	10.18	
Prime Rate	3.25%	
Working Capital Percentage	0.091%	
Working Capital	$ 70,840	
Plus: Working Capital Reconciliation (Acct 142.20)	(63,719)	
Total Working Capital Allowance		7,121
Bad Debt:		
Total Anticipated Direct Cost of Gas 11/01/09 - 04/30/10)	$ 78,151,613	
Less: Refunds	-	
Plus: Total Working Capital	7,121	
Plus: Prior Period (Over)/Under Recovery	935,450	
Subtotal	$ 79,094,183	
Bad Debt Percentage	2.54%	
Bad Debt Allowance	$ 2,008,992	
Plus: Bad Debt Reconciliation (Acct 175.52)	(212,161)	
Total Bad Debt Allowance		$ 1,796,831
Production and Storage Capacity		$ 1,749,387
Miscellaneous Overhead (11/01/09 - 04/30/10)	$ 25,381	
Times Winter Sales	83,802	
Divided by Total Sales	105,710	
Miscellaneous Overhead		20,121
Total Anticipated Indirect Cost of Gas		$ 3,573,460
Total Cost of Gas		$ 81,444,006

Issued: August 31, 2009
Effective: November 1, 2009

Issued By__________________________
Nickolas Stavropoulos
Title: President

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)		(Col 3)	
Total Anticipated Direct Cost of Gas	$	77,870,546			
Projected Prorated Sales (11/01/09 - 04/30/10)		84,282,098			
Direct Cost of Gas Rate			$	0.9239	per therm
Demand Cost of Gas Rate	$	8,016,873	$	0.0951	per therm
Commodity Cost of Gas Rate		70,134,740	$	0.8321	per therm
Adjustment Cost of Gas Rate		(281,067)	$	(0.0033)	per therm
Total Direct Cost of Gas Rate	$	77,870,546	$	0.9239	per therm
Total Anticipated Indirect Cost of Gas	$	3,573,460			
Projected Prorated Sales (11/01/09 - 04/30/10)		84,282,098			
Indirect Cost of Gas			$	0.0424	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09			**$**	**0.9663**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/09		**COGwr**	**$**	**0.9663**	**/therm**
		Maximum (COG + 25%)	$	1.2079	

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09			**COGwl**	**$**	**0.9658**	**/therm**
Average Demand Cost of Gas Rate Effective 11/01/09	$ 0.0951					
Times: Low Winter Use Ratio (Winter)	0.9944	Maximum	(COG + 25%)	$	1.2073	
Times: Correction Factor	1.00080					
Adjusted Demand Cost of Gas Rate	$ 0.0946					
Commodity Cost of Gas Rate	$ 0.8321					
Adjustment Cost of Gas Rate	$ (0.0033)					
Indirect Cost of Gas Rate	$ 0.0424					
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.9658					

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/09			**COGwh**	**$**	**0.9665**	**/therm**
Average Demand Cost of Gas Rate Effective 11/01/09	$ 0.0951					
Times: High Winter Use Ratio (Winter)	1.0008	Maximum	(COG + 25%)	$	1.2081	
Times: Correction Factor	1.00080					
Adjusted Demand Cost of Gas Rate	$ 0.0953					
Commodity Cost of Gas Rate	$ 0.8321					
Adjustment Cost of Gas Rate	$ (0.0033)					
Indirect Cost of Gas Rate	$ 0.0424					
Adjusted Com/Ind High Winter Use Cost of Gas Rate	$ 0.96650					

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Nickolas Stavropoulos
Title: President

CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
(Refer to Text in Section 17(A) Fixed Price Option Program)

(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$ 77,870,546		
Projected Prorated Sales (11/01/09 - 04/30/10)	84,282,098		
Direct Cost of Gas Rate		$ 0.9239	per therm
Demand Cost of Gas Rate	$ 8,016,873	$ 0.0951	per therm
Commodity Cost of Gas Rate	70,134,740	$ 0.8321	per therm
Adjustment Cost of Gas Rate	(281,067)	$ (0.0033)	per therm
Total Direct Cost of Gas Rate	$ 77,870,546	$ 0.9239	per therm
Total Anticipated Indirect Cost of Gas	$ 3,573,460		
Projected Prorated Sales (11/01/09 - 04/30/10)	84,282,098		
Indirect Cost of Gas		$ 0.0424	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 40118		**$ 0.9663**	
FPO Risk Premium		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE 40118		**$ 0.9863**	

RESIDENTIAL COST OF GAS RATE - 11/01/09	**COGwr**	**$ 0.9863**	**/therm**

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09	**COGwl**	**$ 0.9858**	**/therm**

Average Demand Cost of Gas Rate Effective 40118	$ 0.0951
Times: Low Winter Use Ratio (Winter)	$ 0.9944
Times: Correction Factor	1.0008
Adjusted Demand Cost of Gas Rate	$ 0.0946
Commodity Cost of Gas Rate	$ 0.8321
Adjustment Cost of Gas Rate	$ (0.0033)
Indirect Cost of Gas Rate	$ 0.0424
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.9658
FPO Risk Premium	$ 0.0200
	$ 0.9858

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/09	**COGwh**	**$ 0.9865**	**/therm**

Average Demand Cost of Gas Rate Effective 40118	$ 0.0951
Times: High Winter Use Ratio (Winter)	$ 1.0008
Times: Correction Factor	1.000800
Adjusted Demand Cost of Gas Rate	$ 0.0953
Commodity Cost of Gas Rate	$ 0.8321
Adjustment Cost of Gas Rate	$ (0.0033)
Indirect Cost of Gas Rate	$ 0.0424
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.9665
FPO Risk Premium	$ 0.0200
	$ 0.9865

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	(Col 2)		(Col 3)		(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:					
PROPANE	$ -				
LNG	657,484				
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	657,484				
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	12.4%				
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	$ 81,528				
PROJECTED FIRM THROUGHPUT (THERMS):					
FIRM SALES	83,801,811		74.4%		
FIRM TRANSPORTATION SUBJECT TO FTCG	28,847,194		25.6%		
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	112,649,005		100.0%		
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	25.6%	x	$ 81,528	=	$ 20,878
PRIOR (OVER) OR UNDER COLLECTION					(30,075)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS					$ (9,197)
PROJECTED FIRM TRANSPORTATION THROUGHPUT					28,847,194
FIRM TRANSPORTATION COST OF GAS ADJUSTMENT					($0.0003)

Environmental Surcharge - Manufactured Gas Plants

Manfactured Gas Plants		
Required annual increase in rates	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/09 - sales and transportation	150,828,182	therms
Surcharge per therm	$0.0000	per therm
Total Environmental Surcharge	$0.0000	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$	802,635
Temporary Rate Reconciliation		(3,740,913)
Rate Case Expense Reconciliaiton Adjustment		-
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	(2,938,277)

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		92,474,643
Total Volumes		150,828,182
Rate Case Expense Factor	$	(0.0195)

Local Distribution Adjustment Charge Calculation

Residential Non Heating Rates - R-1

Energy Efficiency Charge	$0.0466		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0466	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive			
Interruptible Transportation Margin Credit (ITMC)		0.0040	
Rate Case Expense Factor (RCEF)		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		0.0099	
LDAC		**$0.0410**	**per therm**

Residential Heating Rates - R-3, R-4

Energy Efficiency Charge	$0.0466		
Demand Side Management Charge	(0.0006)		
Conservation Charge (CCx)		$0.0460	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0040	
Rate Case Expense Factor (RCEF)		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		0.0099	
LDAC		**$0.0404**	**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51

Energy Efficiency Charge	$0.0250		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0040	
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		0.0099	
LDAC		**$0.0194**	**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52

Energy Efficiency Charge	$0.0250		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0040	
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		0.0099	
LDAC		**$0.0194**	**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54

Energy Efficiency Charge	$0.0250		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0040	
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		0.0099	
LDAC		**$0.0194**	**per therm**

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ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.12 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	$16.43 MMBTU of Peak MDQ.

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	37.0%	20.0%	43.0%	100.0%
G-51	Low Annual /Low Winter Use	50.0%	16.0%	34.0%	100.0%
G-42	Medium Annual / High Winter	37.0%	20.0%	43.0%	100.0%
G-52	High Annual / Low Winter Use	50.0%	16.0%	34.0%	100.0%
G-43	High Annual / High Winter	37.0%	20.0%	43.0%	100.0%
G-53	High Annual / Load Factor < 90%	50.0%	16.0%	34.0%	100.0%
G-54	G-63	50.0%	16.0%	34.0%	100.0%

CHECK SHEET

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Page	*Revision*
Title	Original
1	~~Fourth~~ Fifth Revised
2	Original
3	~~Fourth~~ Fifth Revised
4	Original
5	~~Original~~ First Revised
6	Original
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10	Original
11	Original
12	Original
13	Original
14	Original
15	Original
16	Original
17	Original
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77	Original
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82	Original
83	Original
84	Original
85	Original
86	~~Original~~ First Revised
87	~~Third~~ Fourth Revised
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89	~~Original~~ First Revised
90	Original
91	~~Original~~ First Revised
92	~~Original~~ First Revised
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94	~~Original~~ First Revised

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155	~~Original~~ First Revised
156	~~Original~~ First Revised

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 9.77			$ 9.77	$ 9.77			$ 9.77
All Therms	$ 0.1507	$ 0.9663	$ 0.0410	$ 1.1580	$ 0.1507	$ 0.5866	$ 0.0254	$ 0.7627
	~~$ 0.1498~~	~~$ 0.9470~~	~~$ 0.0254~~	~~$ 1.1222~~				
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 14.03			$ 14.03	$ 14.03			$ 14.03
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2467	$ 0.9663	$ 0.0404	$ 1.2534	$ 0.2467	$ 0.5866	$ 0.0260	$ 0.8593
	~~$ 0.2453~~	~~$ 0.9470~~	~~$ 0.0260~~	~~$ 1.2183~~				
All therms over the first block per month at	$ 0.1859	$ 0.9663	$ 0.0404	$ 1.1926	$ 0.1859	$ 0.5866	$ 0.0260	$ 0.7985
	~~$ 0.1849~~	~~$ 0.9470~~	~~$ 0.0260~~	~~$ 1.1579~~				
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 5.61			$ 5.61	$ 5.610			$ 5.61
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.0987	$ 0.9663	$ 0.0404	$ 1.1054	$ 0.0987	$ 0.5866	$ 0.0260	$ 0.7113
	~~$ 0.0981~~	~~$ 0.9470~~	~~$ 0.0260~~	~~$ 1.0711~~				
All therms over the first block per month at	$ 0.0744	$ 0.9663	$ 0.0404	$ 1.0811	$ 0.0744	$ 0.5866	$ 0.0260	$ 0.6870
	~~$ 0.0740~~	~~$ 0.9470~~	~~$ 0.0260~~	~~$ 1.0470~~				
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$ 35.08			$ 35.08	$ 35.08			$ 35.08
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2974	$ 0.9665	$ 0.0194	$ 1.2833	$ 0.2974	$ 0.5871	$ 0.0278	$ 0.9123
	~~$ 0.2956~~	~~$ 0.9471~~	~~$ 0.0278~~	~~$ 1.2705~~				
All therms over the first block per month at	$ 0.1934	$ 0.9665	$ 0.0194	$ 1.1793	$ 0.1934	$ 0.5871	$ 0.0278	$ 0.8083
	~~$ 0.1923~~	~~$ 0.9471~~	~~$ 0.0278~~	~~$ 1.1672~~				
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$ 100.24			$ 100.24	$ 100.24			$ 100.24
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.2642	$ 0.9665	$ 0.0194	$ 1.2501	$ 0.2642	$ 0.5871	$ 0.0278	$ 0.8791
	~~$ 0.2627~~	~~$ 0.9471~~	~~$ 0.0278~~	~~$ 1.2376~~				
All therms over the first block per month at	$ 0.1745	$ 0.9665	$ 0.0194	$ 1.1604	$ 0.1745	$ 0.5871	$ 0.0278	$ 0.7894
	~~$ 0.1735~~	~~$ 0.9471~~	~~$ 0.0278~~	~~$ 1.1484~~				
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$ 421.01			$ 421.01	$ 421.01			$ 421.01
All therms over the first block per month at	$ 0.1591	$ 0.9665	$ 0.0194	$ 1.1450	$ 0.0728	$ 0.5871	$ 0.0278	$ 0.6877
	~~$ 0.1582~~	~~$ 0.9471~~	~~$ 0.0278~~	~~$ 1.1331~~				
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$ 35.08			$ 35.08	$ 35.08			$ 35.08
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.1928	$ 0.9658	$ 0.0194	$ 1.1780	$ 0.1928	$ 0.5851	$ 0.0278	$ 0.8057
	~~$ 0.1917~~	~~$ 0.9461~~	~~$ 0.0278~~	~~$ 1.1656~~				
All therms over the first block per month at	$ 0.1245	$ 0.9658	$ 0.0194	$ 1.1097	$ 0.1245	$ 0.5851	$ 0.0278	$ 0.7374
	~~$ 0.1238~~	~~$ 0.9461~~	~~$ 0.0278~~	~~$ 1.0977~~				
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$ 100.24			$ 100.24	$ 100.24			$ 100.24
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.1505	$ 0.9658	$ 0.0194	$ 1.1357	$ 0.1106	$ 0.5851	$ 0.0278	$ 0.7235
	~~$ 0.1496~~	~~$ 0.9461~~	~~$ 0.0278~~	~~$ 1.1235~~				
All therms over the first block per month at	$ 0.1021	$ 0.9658	$ 0.0194	$ 1.0873	$ 0.0637	$ 0.5851	$ 0.0278	$ 0.6766
	~~$ 0.1015~~	~~$ 0.9461~~	~~$ 0.0278~~	~~$ 1.0754~~				
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$ 431.03			$ 431.03	$ 431.03			$ 431.03
All therms over the first block per month at	$ 0.1087	$ 0.9658	$ 0.0194	$ 1.0939	$ 0.0520	$ 0.5851	$ 0.0278	$ 0.6649
	~~$ 0.1081~~	~~$ 0.9461~~	~~$ 0.0278~~	~~$ 1.0820~~				
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$ 431.03			$ 431.03	$ 431.03			$ 431.03
All therms over the first block per month at	$ 0.0355	$ 0.9658	$ 0.0194	$ 1.0207	$ 0.0192	$ 0.5851	$ 0.0278	$ 0.6321
	~~$ 0.3530~~	~~$ 0.9461~~	~~$ 0.0278~~	~~$ 1.3269~~				

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Anticipated Cost of Gas

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010

~~PERIOD COVERED: SUMMER PERIOD, MAY 1, 2009 THROUGH OCTOBER 31, 2009~~

(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 3,059,784~~		$ 6,919,850	
Supply Costs:	~~$ 11,690,887~~		48,398,041	
Storage Gas:				
Demand, Capacity:	~~-~~		1,097,023	
Commodity Costs:	~~-~~		7,583,539	
Produced Gas:	~~70,881~~		657,484	
Hedged Contract Savings	~~2,198,899~~		11,627,343	
Hedge Underground Storage Contract (Savings)/Loss			1,868,333	
Unadjusted Anticipated Cost of Gas		~~$ 17,020,451~~		$ 78,151,613
Adjustments:				
Prior Period (Over)/Under Recovery (as of ~~October 1, 2008~~ May 1, 2009)	~~$ (1,969,485)~~		$ 935,450	
Interest	~~(28,900)~~		49,971	
Prior Period Adjustments	~~162,600~~		-	
Broker Revenues	-		(890,609)	
Refunds from Suppliers	~~-~~		-	
Fuel Financing	~~-~~		210,305	
Transportation CGA Revenues	~~-~~		8,654	
Interruptible Sales Margin	~~-~~		-	
Capacity Release <u>and Off System Sales</u> Margin	~~-~~		(635,528)	
Hedging Costs	~~-~~		-	
Fixed Price Option Administrative Costs	~~-~~		40,691	
Total Adjustments		~~(1,835,785)~~		(281,067)
Total Anticipated Direct Cost of Gas		~~$ 15,184,666~~		$ 77,870,546
Anticipated Indirect Cost of Gas				
Working Capital:				
Total anticipated Direct Cost of Gas ~~(5/01/2008 - 10/31/2008)~~(11/01/08 - 04/30/09)	~~$ 17,020,451~~		$ 78,151,613	
Lead Lag Days			10.18	
Prime Rate			3.25%	
Working Capital Percentage	~~0.645%~~		0.091%	
Working Capital	~~109,782~~		$ 70,840	
Plus: Working Capital Reconciliation ~~(Acct 142.40)~~ (Acct 142.20)	~~(68,107)~~		(63,719)	
Total Working Capital Allowance		~~$ 41,674~~		$ 7,121
Bad Debt:				
Total anticipated Direct Cost of Gas ~~(5/01/2008 - 10/31/2008)~~(11/01/08 - 04/30/09)	~~$ 17,020,451~~		$ 78,151,613	
Less: Refunds	-		-	
Plus: Total Working Capital	~~41,674~~		7,121	
Plus: Prior Period (Over)/Under Recovery	~~(1,969,485)~~		935,450	
Subtotal	~~$ 15,092,641~~		$ 79,094,183	
Bad Debt Percentage	~~1.75%~~		2.54%	
Bad Debt Allowance	~~264,121~~		$ 2,008,992	
Plus: Bad Debt Reconciliation ~~(Acct 175.54)~~ (Acct 175.52)	~~(125,817)~~		(212,161)	
Total Bad Debt Allowance		~~138,304~~		1,796,831
Production and Storage Capacity		~~-~~		1,749,387
Miscellaneous Overhead ~~(5/01/2008 - 10/31/2008)~~ (11/01/08 - 4/30/09)	~~$ 135,339~~		$ 25,381	
Times ~~Summer~~ Winter Sales	~~23,350~~		83,802	
Divided by Total Sales	~~114,873~~		105,710	
Miscellaneous Overhead		~~27,510~~		20,121
Total Anticipated Indirect Cost of Gas		~~$ 207,489~~		$ 3,573,460
Total Cost of Gas		~~$ 15,392,155~~		$ 81,444,006

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CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
~~**PERIOD COVERED: SUMMER PERIOD, MAY 1, 2009 THROUGH OCTOBER 31, 2009**~~
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 15,184,286~~		$ 77,870,546		
Projected Prorated Sales ~~(05/01/09 - 10/31/2009)~~ (11/01/09 - 04/30/10)	~~22,899,858~~		84,282,098		
Direct Cost of Gas Rate		~~0.6631~~		$ 0.9239	per therm
Demand Cost of Gas Rate	~~$ 3,059,784~~	~~0.1336~~	$ 8,016,873	$ 0.0951	
Commodity Cost of Gas Rate	~~13,960,289~~	~~0.6096~~	70,134,740	$ 0.8321	
Adjustment Cost of Gas Rate	~~(1,835,787)~~	~~(0.0802)~~	(281,067)	$ (0.0033)	
Total Direct Cost of Gas Rate	~~$ 15,184,286~~	~~0.6631~~	$ 77,870,546	$ 0.9239	
Total Anticipated Indirect Cost of Gas	~~$ 207,480~~		$ 3,573,460		
Projected Prorated Sales ~~(05/01/09 - 10/31/2009)~~ (11/01/09 - 04/30/10)	~~22,899,858~~		84,282,098		
Indirect Cost of Gas		~~$ 0.0091~~		$ 0.0424	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09				$ 0.9663	per Therm
~~**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/09**~~		~~$ 0.6722~~			

RESIDENTIAL COST OF GAS RATE - 11/01/09	**COGwr**	**$ 0.9663**	**/therm**
~~**RESIDENTIAL COST OF GAS RATE - 5/01/09**~~	~~**COGsr**~~	~~**$ 0.6722**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0398)~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 06/01/2009**~~	~~**COGsr**~~	~~**$ 0.6324**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0124)~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 07/01/2009**~~	~~**COGsr**~~	~~**$ 0.6200**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0123)~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 08/01/2009**~~	~~**COGsr**~~	~~**$ 0.6077**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0211)~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 09/01/2009**~~	~~**COGsr**~~	~~**$ 0.5866**~~	~~**/therm**~~

Maximum (COG + 25%) ~~$ 0.8403~~ $ 1.2079

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09	**COGwl**	**$ 0.9658**	**/therm**
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/09**~~	~~**COGsl**~~	~~**$ 0.6707**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0398)~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 06/01/2009**~~	~~**COGsl**~~	~~**$ 0.6309**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~**$ (0.0124)**~~	~~**/therm**~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 7/01/2009**~~	~~**COGsl**~~	~~**$ 0.6185**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0123)~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 08/01/2009**~~	~~**COGsl**~~	~~**$ 0.6062**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0211)~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 09/01/2009**~~	~~**COGsl**~~	~~**$ 0.5851**~~	~~**/therm**~~

Average Demand Cost of Gas Rate Effective ~~5/01/09~~11/01/2009	~~$ 0.1336~~	$ 0.0951	Maximum	(COG + 25%)	~~$ 0.8384~~	$ 1.2073
Times: Low Winter Use Ratio (Winter)	~~0.9869~~	0.9944				
Times: Correction Factor	~~1.00261~~	1.00080				
Adjusted Demand Cost of Gas Rate	~~$ 0.1322~~	$ 0.0946				
Commodity Cost of Gas Rate	~~$ 0.6096~~	$ 0.8321				
Adjustment Cost of Gas Rate	~~$ (0.0802)~~	(0.0033)				
Indirect Cost of Gas Rate	~~$ 0.0091~~	0.04240				
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 0.6707~~	$ 0.9658				

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/09	**COGwh**	**$ 0.9665**	**/therm**
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/09**~~	~~**COGsh**~~	~~**$ 0.6727**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0398)~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE -06/01/2009**~~	~~**COGsh**~~	~~**$ 0.6329**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0124)~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 07/01/2009**~~	~~**COGsh**~~	~~**$ 0.6205**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0123)~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE -08/01/2009**~~	~~**COGsh**~~	~~**$ 0.6082**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ (0.0211)~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 9/01/2009**~~	~~**COGsh**~~	~~**$ 0.5871**~~	~~**/therm**~~

Average Demand Cost of Gas Rate Effective ~~5/01/09~~11/01/2009	~~$ 0.1336~~	$ 0.0951	Maximum	(COG + 25%)	~~$ 0.8409~~	$ 1.2081
Times: High Winter Use Ratio (Winter)	~~1.0022~~	1.0008				
Times: Correction Factor	~~1.00261~~	1.00080				
Adjusted Demand Cost of Gas Rate	~~$ 0.1342~~	$ 0.0953				
Commodity Cost of Gas Rate	~~$ 0.6096~~	$ 0.8321	Minimum			
Adjustment Cost of Gas Rate	~~$ (0.0802)~~	$ (0.0033)	Maximum			
Indirect Cost of Gas Rate	~~$ 0.0091~~	$ 0.0424				
Adjusted Com/Ind High Winter Use Cost of Gas Rate	~~$ 0.6727~~	$ 0.9665				

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Effective: November 1, 2009

Issued: By________________________
Nickolas Stavropoulos
Title: President

II. RATE SCHEDULES
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
~~PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2008 THROUGH APRIL 30, 2009~~
(Refer to Text in Section 17(A) Fixed Price Option Program)

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 111,027,254~~		$ 77,870,546		
Projected Prorated Sales ~~(11/01/2008 - 4/30/2009)~~ (11/01/2009 - 4/30/2010)	~~90,372,901~~		84,282,098		
Direct Cost of Gas Rate		~~$ 1.2285~~		$ 0.9239	per therm
Demand Cost of Gas Rate	~~$ 7,672,333~~	~~$ 0.0849~~	$ 8,016,873	$ 0.0951	
Commodity Cost of Gas Rate	~~$ 101,239,991~~	~~$ 1.1202~~	$ 70,134,740	$ 0.8321	
Adjustment Cost of Gas Rate	~~$ 2,114,930~~	~~$ 0.0234~~	$ (281,067)	$ (0.0033)	
Total Direct Cost of Gas Rate	~~$ 111,027,254~~	~~$ 1.2285~~	$ 77,870,546	$ 0.9239	
Total Anticipated Indirect Cost of Gas	~~$ 3,163,335~~		$ 3,573,460		
Projected Prorated Sales ~~(11/01/2008 - 4/30/2009)~~ (11/01/2009 - 4/30/2010)	~~90,372,901~~		84,282,098		
Indirect Cost of Gas		~~$ 0.0350~~		$ 0.0424	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE NOVEMBER 1, 2009 ~~2008~~		~~**$ 1.2635**~~		**$ 0.9663**	
FPO Risk Premium		~~$ 0.0200~~		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE NOVEMBER 1, 2009 ~~2008~~		~~**$ 1.2835**~~		**$ 0.9863**	

RESIDENTIAL COST OF GAS RATE - 11/01/09			**COGwr**	**$ 0.9863**	**/therm**
~~**RESIDENTIAL COST OF GAS RATE -11/01/2008**~~	-	~~**COGwr**~~	~~**$ 1.2835**~~	~~**/therm**~~	

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09			**COGwl**	**$ 0.9858**	**/therm**
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/2008**~~	-	~~**COGwr**~~	~~**$ 1.2830**~~	~~**/therm**~~	

Average Cost of Gas Rate Effective ~~11/01/2008~~ 11/01/2009	~~$ 0.0849~~	$ 0.0951
Times: Low Winter Use Ratio (Winter)	~~$ 0.9947~~	$ 0.9944
Times: Correction Factor	~~$ 0.999988~~	$ 1.000800
Adjusted Demand Cost of Gas Rate	~~$ 0.0844~~	$ 0.0946
Commodity Cost of Gas Rate	~~$ 1.1202~~	$ 0.8321
Adjustment Cost of Gas Rate	~~$ 0.0234~~	$ (0.0033)
Indirect Cost of Gas Rate	~~$ 0.0350~~	$ 0.0424
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 1.2630~~	$ 0.9658
FPO Risk Premium	~~$ 0.0200~~	$ 0.0200
	~~$ 1.2830~~	$ 0.9858

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/09			**COGwh**	**$ 0.9865**	**/therm**
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/2008**~~	-	~~**COGwr**~~	~~**$ 1.2836**~~	~~**/therm**~~	

Average Cost of Gas Rate Effective ~~11/01/2008~~ 11/01/2009	~~$ 0.0849~~	$ 0.0951
Times: High Winter Use Ratio (Winter)	~~$ 1.0009~~	$ 1.0008
Times: Correction Factor	~~$ 0.999988~~	$ 1.000800
Adjusted Demand Cost of Gas Rate	~~$ 0.0850~~	$ 0.0953
Commodity Cost of Gas Rate	~~$ 1.1202~~	$ 0.8321
Adjustment Cost of Gas Rate	~~$ 0.0234~~	$ (0.0033)
Indirect Cost of Gas Rate	~~$ 0.0350~~	$ 0.0424
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 1.2636~~	$ 0.9665
FPO Risk Premium	~~$ 0.0200~~	$ 0.0200
	~~$ 1.2836~~	$ 0.9865

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010
~~PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2008 THROUGH APRIL 30, 2009~~
(Refer to text in Section16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	~~(Col 4)~~	(Col 2)	(Col 3)	(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:						
PROPANE	~~$ 1,411,827~~			$ -		
LNG	~~$ 1,036,505~~			657,484		
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	~~2,448,332~~			657,484		
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	~~14.1%~~			12.4%		
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	~~$ 345,215~~			$ 81,528		
PROJECTED FIRM THROUGHPUT (THERMS):						
FIRM SALES	~~91,523,044~~	~~78.2%~~		83,801,811	74.4%	
FIRM TRANSPORTATION SUBJECT TO FTCG	~~25,462,089~~	~~21.8%~~		28,847,194	25.6%	
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	~~116,985,133~~	~~100.0%~~		112,649,005	100.0%	
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	~~21.8%~~	~~345,214.81~~ =	~~$ 75,137~~	25.6% x	$ 81,528 =	$ 20,878
PRIOR (OVER) OR UNDER COLLECTION			~~(76,753)~~			(30,075)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS			~~$ (1,616)~~			$ (9,197)
PROJECTED FIRM TRANSPORTATION THROUGHPUT			~~25,462,089~~			28,847,194
FIRM TRANSPORTATION COST OF GAS ADJUSTMENT			~~($0.0001)~~			($0.0003)

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Issued: By____________________________
Nickolas Stavropoulos
Title: President

Environmental Surcharge - Manufactured Gas Plants

Manfactured Gas Plants

Required annual increase in rates	~~$0~~	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/10 ~~10/31/09~~ - sales and transportation	~~154,702,063~~	150,828,182	therms
Surcharge per therm	~~$0.0000~~	$0.0000	per therm
Total Environmental Surcharge	~~$0.0000~~	$0.0000	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$	-
Temporary Rate Reconciliation		-
Rate Case Expense Reconciliaiton Adjustment		-
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	-

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)	92,474,643
Total Volumes	150,828,182

Rate Case Expense Factor	$	-

Local Distribution Adjustment Charge Calculation

Residential Non Heating Rates - R-1					
Energy Efficiency Charge	~~$0.0181~~		$0.0466		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0181~~		$0.0466	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0000~~		0.0040	
Rate Case Expense Factor (RCEF)		~~0.0000~~		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		~~0.0073~~		0.0099	
LDAC		**~~$0.0254~~**		**$0.0410**	**per therm**

Residential Heating Rates - R-3, R-4					
Energy Efficiency Charge	~~$0.0181~~		$0.0466		
Demand Side Management Charge	~~0.0006~~		(0.0006)		
Conservation Charge (CCx)		~~$0.0187~~		$0.0460	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0000~~		0.0040	
Rate Case Expense Factor (RCEF)		~~0.0000~~		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		~~0.0073~~		0.0099	
LDAC		**~~$0.0260~~**		**$0.0404**	**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51					
Energy Efficiency Charge	~~$0.0205~~		$0.0250		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0205~~		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0000~~		0.0040	
Gas Restructuring Expense Factor (GREF)		~~0.0000~~		0.0000	
Rate Case Expense Factor (RCEF)		~~0.0000~~		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		~~0.0073~~		0.0099	
LDAC		**~~$0.0278~~**		**$0.0194**	**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52					
Energy Efficiency Charge	~~$0.0205~~		$0.0250		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0205~~		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0000~~		0.0040	
Gas Restructuring Expense Factor (GREF)		~~0.0000~~		0.0000	
Rate Case Expense Factor (RCEF)		~~0.0000~~		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		~~0.0073~~		0.0099	
LDAC		**~~$0.0278~~**		**$0.0194**	**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54					
Energy Efficiency Charge	~~$0.0205~~		$0.0250		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0205~~		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0000~~		0.0040	
Gas Restructuring Expense Factor (GREF)		~~0.0000~~		0.0000	
Rate Case Expense Factor (RCEF)		~~0.0000~~		(0.0195)	
Residential Low Income Assistance Program (RLIAP)		~~0.0073~~		0.0099	
LDAC		**~~$0.0278~~**		**$0.0194**	**per therm**

ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	~~$0.12~~	$0.12 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee		15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	~~$10.02~~	$16.43 MMBTU of Peak MDQ.

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	~~33%~~ 37.0%	~~20%~~ 20.0%	~~47%~~ 43.0%	100.0%
G-51	Low Annual /Low Winter Use	~~46%~~ 50.0%	~~16%~~ 16.0%	~~38%~~ 34.0%	100.0%
G-42	Medium Annual / High Winter	~~33%~~ 37.0%	~~20%~~ 20.0%	~~47%~~ 43.0%	100.0%
G-52	High Annual / Low Winter Use	~~46%~~ 50.0%	~~16%~~ 16.0%	~~38%~~ 34.0%	100.0%
G-43	High Annual / High Winter	~~33%~~ 37.0%	~~20%~~ 20.0%	~~47%~~ 43.0%	100.0%
G-53	High Annual / Load Factor < 90%	~~46%~~ 50.0%	~~16%~~ 16.0%	~~38%~~ 34.0%	100.0%
G-54	High Annual / Load Factor > 90%	~~46%~~ 50.0%	~~16%~~ 16.0%	~~38%~~ 34.0%	100.0%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing

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1	**ENERGY NORTH NATURAL GAS, INC.**		
2	**d/b/a National Grid NH**		
3	**Peak 2009 - 2010 Winter Cost of Gas Filing**		
4	**Summary**		
5			PK 09-10
6		Reference	Nov - Apr
7	(a)	(b)	(c)
8			
9	**Anticipated Direct Cost of Gas**		
10	Purchased Gas:		
11	Demand Costs:	Sch. 5A, col (j), ln 43	$ 6,919,850
12	Supply Costs	Sch. 6, col (i), ln 43	48,398,041
13			
14	Storage Gas:		
15	Demand, Capacity:	Sch. 5A, col (j), ln 58	$ 1,097,023
16	Commodity Costs:	Sch. 6, col (i), ln 46	7,583,539
17			
18	Produced Gas:	Sch. 6, col (i), ln 52	$ 657,484
19			
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$ 11,627,343
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (g), ln 199	$ 1,868,333
22			
23	**Total Unadjusted Cost of Gas**		$ 78,151,613
24			
25	**Adjustments:**		
26			
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$ 935,450
28	Interest 10/31/09 - 04//30/10	Sch. 3, col ln 192	49,971
29	Prior Period Adjustments	Sch. 4, ln 24 col (b)	-
30	Refunds from Suppliers	Sch. 4, ln 24 col (c)	-
31	Broker Revenues	Sch. 4, ln 24 col (d)	(890,609)
32	Fuel Financing	Sch. 4, ln 24 col (e)	210,305
33	Transportation CGA Revenues	Sch. 4, ln 24 col (f)	8,654
34	Interruptible Sales Margin	Sch. 4, ln 24 col (g)	-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)	(635,528)
36	Hedging Costs	Sch. 4, ln 24 col (j)	-
37	FPO Premium - Collection		
37	Fixed Price Option Administrative Costs	Sch. 4, ln 24 col (k)	40,691
38			
39	**Total Adjustments**		$ (281,067)
40			
41	**Total Anticipated Direct Costs**	lns 23 + 39	$ 77,870,546
42			
43	**Anticipated Indirect Cost of Gas**		
44	**Working Capital**		
45	Total Anticipated Direct Cost of Gas	Ln 23	$ 78,151,613
46	Lead Lag Days		10.18
47	Prime Rate		3.25%
48	Working Capital Percentage	per GTC 16(f)	0.091%
49	Working Capital	ln 45 * ln 48	70,840
50	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 92	(63,719)
51			
52	**Total Working Capital Allowance**	lns 49 + 50	$ 7,121
53			
54	**Bad Debt**		
55	Total Anticipated Direct Cost of Gas	ln 45	$ 78,151,613
56	Less Refunds		-
57	Plus Working Capital	ln 52	7,121
58	Plus Prior Period (Over) Under Recovery	ln 27	935,450
59	Subtotal		$ 79,094,183
60	Bad Debt Percentage	per GTC 16(f)	2.54%
61			
62	Bad Debt Allowance	ln 59 * ln 60	$ 2,008,992
63	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 161	(212,161)
64			
65	**Total Bad Debt Allowance**	lns 62 + 63	$ 1,796,831
66			
67	**Production and Storage Capacity**	per GTC16(f)	$ 1,749,387
68			
69	**Miscellaneous Overhead**	per GTC 16(f)	$ 25,381
70	Sales Volume	Sch. 10B, ln 23/1000	83,802
71	Divided by Total Sales	Sch. 10B, ln 23/1000	105,710
72	Ratio		79.28%
73			
74	**Miscellaneous Overhead**	lns 69 * 72	$ 20,121
75			
76	**Total Anticipated Indirect Cost of Gas**	lns 52 + 65 + 67 + 74	$ 3,573,460
77			
78	**Total Cost of Gas**	lns 41 + 76	$ 81,444,006
79			
80	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52	84,282,098

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Line	For Month of:		Peak Costs May 09 - Oct 09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Peak Period Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10											
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	3,602,796	13,331,541	18,028,109	18,410,394	15,782,564	11,043,611	4,083,082	84,282,098
13	Lost Gas (Unaccounted for)		-	166,500	246,946	298,052	241,401	206,579	121,255		1,280,734
14	Company Use		-	109,449	162,330	195,925	158,685	135,794	79,707		841,891
15	Unbilled Therms		-	7,354,208	2,919,427	1,586,015	(2,524,355)	(2,188,116)	(3,064,099)	(4,083,082)	(0)
16											
17	**Total Firm Volumes**	Sch. 6, ln 91	-	11,232,954	16,660,245	20,108,101	16,286,125	13,936,821	8,180,475		86,404,722
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 62	-	1,020,327	1,054,338	1,054,338	952,306	1,054,338	1,020,327		6,155,975
22	Niagara Supply	Sch. 6, ln 63	-	796,706	777,149	783,101	638,555	820,513	98,632		3,914,656
23	TGP Supply (Direct)	Sch. 6, ln 64	-	5,448,548	5,669,619	5,692,576	5,103,337	5,692,576	5,212,172		32,818,830
24	Dracut Winter Supply 1	Sch. 6, ln 65	-	-	6,530,945	6,530,945	5,899,193	-	-		18,961,083
25	Dracut Winter Supply 2	Sch. 6, ln 66	-	4,544,708	151,349	599,442	174,306	6,274,163	5,858,380		17,602,348
26	City Gate Delivered Supply	Sch. 6, ln 67	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 68	-	23,808	124,990	407,281	244,879	49,316	-		850,273
28	Propane Truck	Sch. 6, ln 69	-	-	-	-	-	-	-		-
29	PNGTS	Sch. 6, ln 70	-	62,070	79,926	93,530	73,974	70,573	49,316		429,388
30	Granite Ridge	Sch. 6, ln 71	-	-	-	-	-	-	-		-
31	Subtotal Pipeline Volumes		-	11,896,167	14,388,316	15,161,214	13,086,549	13,961,479	12,238,827		80,732,552
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 76	-	-	2,564,423	4,911,176	3,179,170	-	-		10,654,768
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 79	-	23,808	124,990	442,992	265,285	24,658	24,658		906,391
38	Propane	Sch. 6, ln 80	-	-	-	-	-	-	-		-
39	Subtotal Produced Gas		-	23,808	124,990	442,992	265,285	24,658	24,658		906,391
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 85	-	(23,808)	(124,990)	(407,281)	(244,879)	(49,316)	-		(850,273)
43	Propane	Sch. 6, ln 86	-	-	-	-	-	-	-		-
44	TGP Storage Refill	Sch. 6, ln 87	-	(663,213)	(292,494)	-	-	-	(4,083,010)		(5,038,717)
45	Subtotal Refills		-	(687,020)	(417,484)	(407,281)	(244,879)	(49,316)	(4,083,010)		(5,888,989)
46											
47	Total Firm Sendout Volumes		-	11,232,954	16,660,245	20,108,101	16,286,125	13,936,821	8,180,475		86,404,722
48											

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln	Description	Reference	Peak Costs May 09 - Oct 09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Peak Period Nov - Apr
6											
7	For Month of:										
49	**II. Gas Costs**										
50											
51	**A. Demand Costs**										
52	Supply										
53	Niagra Supply	Sch.5A, ln 12									
54	Subtotal Supply Demand										
55	Less Capacity Credit										
56	Net Pipeline Demand Costs										
57											
58	Pipeline:										
59	Iroquois Gas Trans Service RTS 470	Sch.5A, ln 16									
60	Tenn Gas Pipeline 33371	Sch.5A, ln 17									
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18									
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19									
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20									
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21									
65	Tenn Gas Pipeline (Dracut) 42076 Z	Sch.5A, ln 22									
66	Tenn Gas Pipeline (Concord Lateral)	Sch.5A, ln 23									
67	Portland Natural Gas Trans Service	Sch.5A, ln 24									
68	ANE (TransCanada via Union to Iroq	Sch.5A, ln 25									
69	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 26									
70	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 27									
71	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 28									
72	National Fuel FST 2358	Sch.5A, ln 29									
73	Subtotal Pipeline Demand		$ 970,611	$ 790,177	$ 790,177	$ 790,177	$ 790,177	$ 790,177	$ 790,177		$ 5,711,673
74	Less Capacity Credit		(154,269)	(118,307)	(118,307)	(118,307)	(118,307)	(118,307)	(118,307)		(864,112)
75	Net Pipeline Demand Costs		$ 816,342	$ 671,870	$ 671,870	$ 671,870	$ 671,870	$ 671,870	$ 671,870		$ 4,847,562
76											
77	Peaking Supply:										
	Tenn Gas Pipeline (Concord Lateral)	Sch.5A, ln 34									
78	Granite Ridge Demand	Sch.5A, ln 35									
79	DOMAC Demand FLS-160	Sch.5A, ln 36									
80	Subtotal Peaking Demand		$ 120,000	$ 397,864	$ 397,864	$ 397,864	$ 397,864	$ 397,864	$ 324,250		$ 2,433,569
81	Less Capacity Credit		(19,073)	(59,569)	(59,569)	(59,569)	(59,569)	(59,569)	(48,547)		(365,466)
82	Net Peaking Supply Demand Costs		$ 100,927	$ 338,295	$ 338,295	$ 338,295	$ 338,295	$ 338,295	$ 275,703		$ 2,068,103
83											
84	Storage:										
85	Dominion - Demand	Sch.5A, ln 46									
86	Dominion - Storage	Sch.5A, ln 47									
87	Honeoye - Demand	Sch.5A, ln 48									
88	National Fuel - Demand	Sch.5A, ln 49									
89	National Fuel - Capacity	Sch.5A, ln 50									
90	Tenn Gas Pipeline - Demand	Sch.5A, ln 51									
91	Tenn Gas Pipeline - Capacity	Sch.5A, ln 52									
92	Subtotal Storage Demand		$ 648,613	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 108,102		$ 1,297,225
93	Less Capacity Credit		(103,091)	(16,185)	(16,185)	(16,185)	(16,185)	(16,185)	(16,185)		(200,202)
94	Net Storage Demand Costs		$ 545,522	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 91,917		$ 1,097,023
95											
96	Total Demand Charges	lns 54 + 73 + 80 + 92	$ 1,739,223	$ 1,296,959	$ 1,296,986	$ 1,296,986	$ 1,296,904	$ 1,296,986	$ 1,223,345		$ 9,447,389
97	Total Capacity Credit	lns 55 + 74 + 81 + 93	(276,432)	(194,184)	(194,188)	(194,188)	(194,175)	(194,188)	(183,162)		(1,430,516)
98	Net Demand Charges		$ 1,462,791	$ 1,102,775	$ 1,102,798	$ 1,102,798	$ 1,102,729	$ 1,102,798	$ 1,040,183		$ 8,016,873
99											
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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Ln			Peak Costs May 09 - Oct 09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Peak Period Nov - Apr
5											
6											
7	For Month of:										
101	**B. Commodity Costs**										
102	Pipeline:										
103	Dawn Supply	Sch. 6, ln 12									
104	Niagara Supply	Sch. 6, ln 13									
105	TGP Supply (Direct)	Sch. 6, ln 14									
106	Dracut Winter Supply 1	Sch. 6, ln 15									
107	Dracut Winter Supply 2	Sch. 6, ln 16									
108	City Gate Delivered Supply	Sch. 6, ln 17									
109	LNG Truck	Sch. 6, ln 18									
110	Propane Truck	Sch. 6, ln 19									
111	PNGTS	Sch. 6, ln 20									
112	Granite Ridge	Sch. 6, ln 21									
113	Subtotal Pipeline Commodity Costs		$ -	$ 5,841,340	$ 8,663,193	$ 10,150,336	$ 8,725,381	$ 8,571,653	$ 7,049,190		$ 49,001,094
114											
115	Storage:										
116	TGP Storage - Withdrawals	Sch. 6, ln 46	$ -	$ -	$ 1,844,255	$ 3,483,984	$ 2,255,300	$ -	$ -		$ 7,583,539
117											
118	Produced Gas Costs:										
119	LNG Vapor	Sch. 6, ln 49									
120	Propane	Sch. 6, ln 50									
121	Subtotal Produced Gas Costs		$ -	$ 18,241	$ 92,217	$ 319,866	$ 191,551	$ 17,804	$ 17,804		$ 657,484
122											
123	Less Storage Refills:										
124	LNG Truck	Sch. 6, ln 36									
125	Propane	Sch. 6, ln 37									
126	TGP Storage Refill	Sch. 6, ln 38									
127	Storage Refill (Trans.)	Sch. 6, ln 39									
128	Subtotal Storage Refill		$ -	$ (351,899)	$ (241,250)	$ (229,476)	$ (138,786)	$ (27,731)	$ (2,491,892)		$ (3,481,033)
129											
130	Total Supply Commodity Costs		$ -	$ 5,507,681	$ 10,358,415	$ 13,724,711	$ 11,033,447	$ 8,561,727	$ 4,575,102		$ 53,761,084
131											
132	**C. Supply Volumetric Transportation Costs:**										
133	Dawn Supply	Sch. 6, ln 26									
134	Niagara Supply	Sch. 6, ln 27									
135	TGP Supply (Direct)	Sch. 6, ln 28									
136	Dracut Winter Supply 1	Sch. 6, ln 29									
137	Dracut Winter Supply 2	Sch. 6, ln 30									
138	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 375,100	$ 461,534	$ 490,182	$ 436,524	$ 470,643	$ 377,895		$ 2,611,878
139											
140	TGP Storage - Withdrawals	Sch. 6, ln 31	$ -	$ -	$ 64,459	$ 122,406	$ 79,238	$ -	$ -		$ 266,103
141											
142	Total Supply Volumetric Trans. Costs		$ -	$ 375,100	$ 525,993	$ 612,588	$ 515,762	$ 470,643	$ 377,895		$ 2,877,981
143											
144	Total Commodity Gas & Trans. Costs	lns 130 + 142	$ -	$ 5,882,782	$ 10,884,408	$ 14,337,299	$ 11,549,209	$ 9,032,370	$ 4,952,997		$ 56,639,065
145											
146											

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line	Description	Reference	Peak Costs May 09 - Oct 09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Peak Period Nov - Apr
7	For Month of:										
147	**D. Supply and Demand Costs by Source**										
148											
149	Purchased Gas Demand Costs										
150	Pipeline Gas Demand Costs	lns 54 + 73	$ 970,611	$ 790,993	$ 791,020	$ 791,020	$ 790,938	$ 791,020	$ 790,993		$ 5,716,595
151	Peaking Gas Demand Costs	ln 80	120,000	397,864	397,864	397,864	397,864	397,864	324,250		2,433,569
152	Subtotal Purchased Gas Demand Costs		$ 1,090,611	$ 1,188,857	$ 1,188,884	$ 1,188,884	$ 1,188,802	$ 1,188,884	$ 1,115,243		$ 8,150,164
153	Less Capacity Credit	lns 55 + 74 + 81	(173,342)	(177,998)	(178,002)	(178,002)	(177,990)	(178,002)	(166,977)		(1,230,314)
154	Net Purchased Gas Demand Costs		$ 917,269	$ 1,010,858	$ 1,010,881	$ 1,010,881	$ 1,010,812	$ 1,010,881	$ 948,266		$ 6,919,850
155											
156	Storage Gas Demand Costs										
157	Storage Demand	ln 92	$ 648,613	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 108,102		$ 1,297,225
158	Less Capacity Credit	ln 93	(103,091)	(16,185)	(16,185)	(16,185)	(16,185)	(16,185)	(16,185)		(200,202)
159	Net Storage Demand Costs		$ 545,522	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 91,917		$ 1,097,023
160											
161	**Total Demand Costs**	lns 154 + 159	$ 1,462,791	$ 1,102,775	$ 1,102,798	$ 1,102,798	$ 1,102,729	$ 1,102,798	$ 1,040,183		$ 8,016,873
162											
163	Purchased Gas Supply										
164	Commodity Costs	ln 113	$ -	$ 5,841,340	$ 8,663,193	$ 10,150,336	$ 8,725,381	$ 8,571,653	$ 7,049,190		$ 49,001,094
165	Less Storage Inj.(TGP Storage)	ln 126									
166	Less Storage Transportation	ln 127									
167	Less LNG Truck	ln 124									
168	Less Propane Truck	ln 125									
169	Plus Transportation Costs	ln 138									
170	Subtotal Purchased Gas Supply		$ -	$ 5,864,541	$ 8,883,477	$ 10,411,043	$ 9,023,119	$ 9,014,566	$ 4,935,192		$ 48,131,939
171											
172	Storage Commodity Costs										
173	Commodity Costs	ln 116	$ -	$ -	$ 1,844,255	$ 3,483,984	$ 2,255,300	$ -	$ -		$ 7,583,539
174	Transportation Costs	ln 140	-	-	64,459	122,406	79,238	-	-		266,103
175	Subtotal Storage Commodity Costs		$ -	$ -	$ 1,908,714	$ 3,606,390	$ 2,334,538	$ -	$ -		$ 7,849,642
176											
177	Produced Gas Commodity Costs	ln 121	$ -	$ 18,241	$ 92,217	$ 319,866	$ 191,551	$ 17,804	$ 17,804		$ 657,484
178											
179	**SubTotal Commodity Costs**	lns 170 + 175 + 177	$ -	$ 5,882,782	$ 10,884,408	$ 14,337,299	$ 11,549,209	$ 9,032,370	$ 4,952,997		$ 56,639,065
180											
181	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ 1,585,510	$ 2,308,749	$ 2,370,080	$ 2,374,733	$ 1,953,395	$ 1,034,876		$ 11,627,343
182											
183	**Total Commodity Costs**	lns 179 + 181	$ -	$ 7,468,291	$ 13,193,157	$ 16,707,379	$ 13,923,942	$ 10,985,765	$ 5,987,873		$ 68,266,408
184											
181	**Total Demand Costs**	ln 98	$ 1,462,791	$ 1,102,775	$ 1,102,798	$ 1,102,798	$ 1,102,729	$ 1,102,798	$ 1,040,183		$ 8,016,873
182	**Total Supply Costs**	ln 183	-	7,468,291	13,193,157	16,707,379	13,923,942	10,985,765	5,987,873		68,266,408
183											
184	**Total Direct Gas Costs**	lns 181 + 182	$ 1,462,791	$ 8,571,066	$ 14,295,955	$ 17,810,177	$ 15,026,671	$ 12,088,564	$ 7,028,056		$ 76,283,280

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Line	Supplier (a)	Contract (b)	Contract Type (c)	Contract Unit (d)	Unit Dth (MDQ/ACQ) (e)	Peak Period Cost per Unit Dth (f)
1	**ENERGY NORTH NATURAL GAS, INC.**					
2	**d/b/a National Grid NH**					
3	**Peak 2009 - 2010 Winter Cost of Gas Filing**					
4	**Contracts Ranked on a per Unit Cost Basis**					
5						
6						
7						
8						
9	**Demand Costs**					
10	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
11	Tenn Gas Pipeline - Cap. Reservations	FS-MA	Storage	ACQ	1,560,391	
12	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
13	Niagra Supply		Supply	MDQ	3,199	
14	Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
15	Granite Ridge Demand		Peaking	MDQ	15,000	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
18	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
19	National Fuel	FST 2358	Transportation	MDQ	6,098	
20	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
21	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
22	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
23	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
24	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
25	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
26	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
27	ANE (TransCanada via Union to Iroquois)	Union Dawn to Iroquois	Transportation	MDQ	4,047	
28	Tenn Gas Pipeline	33371	Transportation	MDQ	4,000	
29	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Z6-Z6	Transportation	MDQ	30,000	
30	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
31	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
32	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
33	DOMAC Liquid Demand Charge		Peaking	MDQ	6,300	
34						
35	**Supply Costs - Commodity**					
36	LNG Vapor (Storage)		Produced	Dkt	90,639	
37	City Gate Delivered Supply		Pipeline	Dkt	-	
38	LNG Truck		Pipeline	Dkt	85,027	
39	TGP Supply (Direct)		Pipeline	Dkt	3,281,883	
40	Dracut Winter Supply 1		Pipeline	Dkt	1,896,108	
41	Granite Ridge		Pipeline	Dkt	-	
42	Dawn Supply		Pipeline	Dkt	615,598	
43	Niagara Supply		Pipeline	Dkt	391,466	
44	PNGTS		Pipeline	Dkt	42,939	
45	Dracut Winter Supply 2		Pipeline	Dkt	1,760,235	
46	TGP Storage		Storage	Dkt	1,065,477	
47	Propane		Produced	Dkt	-	
48	Propane Truck		Pipeline	Dkt	-	
49						
50	**Supply Costs - Volumetric Transportation**					
51	Dracut Winter Supply 1		Pipeline	Dkt	1,896,108	
52	Dracut Winter Supply 2		Pipeline	Dkt	1,760,235	
53	Niagara Supply		Pipeline	Dkt	391,466	
54	TGP Storage - Withdrawals		Pipeline	Dkt	1,065,477	
55	Dawn Supply		Pipeline	Dkt	615,598	
56	TGP Supply (Direct)		Pipeline	Dkt	3,281,883	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

5			Prior Period Balance														
6			Apr-09														
7			Ending Bal	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Peak Period
8		Days in Month	Plus May Billings	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Accunt 175.20 COG (Over)/Under Balance - Interest Calculation**																
12	**Beginning Balance**	Account 175.20 1/	**$ 4,476,672**	$ 935,450	$ 1,462,564	$ 1,499,697	$ 1,884,654	$ 2,400,926	$ 2,842,136	$ 3,351,448	$ 1,935,620	$ 1,105,234	$ 610,438	$ 867,612	$ 357,593	$ 58,427	$ 4,476,672
13	Fcst Direct Gas Costs(Incl U/G Hedge	Schedule 5A		577,491	564,695	534,977	575,570	548,477	529,913	8,571,066	14,295,955	17,810,177	15,026,671	12,088,564	7,028,056	-	78,151,613
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	294,918	294,918	294,918	294,918	294,918	294,918		1,769,508
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(3,402,120)	(12,588,974)	(17,023,943)	(17,384,935)	(14,903,476)	(10,428,482)	(3,855,655)	(79,587,585)
16	Projected Unbilled Revenue									(6,944,579)	(9,701,394)	(11,199,069)	(8,815,321)	(6,749,083)	(3,855,654)		(47,265,100)
17	Reverse Prior Month Unbilled										6,944,579	9,701,394	11,199,069	8,815,321	6,749,083	3,855,654	47,265,100
18	Prior Period Adjustment				-					-							-
19	Add Net Adjustments	Schedule 4		(58,562)	(531,514)	(154,684)	(65,205)	(114,261)	(29,138)	57,834	(79,660)	(80,638)	(65,068)	(57,951)	(87,642)	-	(1,266,487)
20	Gas Cost Billed	Account 175.20 2/	(3,541,223)	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,541,223)
21	Monthly (Over)/Under Recovery		$ 935,450	$ 1,454,378	$ 1,495,745	$ 1,879,990	$ 2,395,020	$ 2,835,143	$ 3,342,912	$ 1,928,568	$ 1,101,043	$ 608,074	$ 865,772	$ 355,905	$ 57,872	$ 58,427	$ 2,498
22	Average Monthly Balance	(ln 12 + 21)/2		$ 2,965,525	$ 1,479,155	$ 1,689,843	$ 2,139,837	$ 2,618,034	$ 3,092,524	$ 2,640,008	$ 1,518,331	$ 856,654	$ 738,105	$ 611,759	$ 207,733	$ 58,427	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 8,186	$ 3,951	$ 4,664	$ 5,907	$ 6,993	$ 8,536	$ 7,052	$ 4,191	$ 2,365	$ 1,840	$ 1,689	$ 555	$ -	$ 55,929
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 935,450	$ 1,462,564	$ 1,499,697	$ 1,884,654	$ 2,400,926	$ 2,842,136	$ 3,351,448	$ 1,935,620	$ 1,105,234	$ 610,438	$ 867,612	$ 357,593	$ 58,427	$ 58,427	58,427
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	ln 12	$ 4,476,672	$ 935,450	$ 1,462,564	$ 1,499,697	$ 1,884,654	$ 2,400,926	$ 2,842,136	$ 3,351,448	$ 1,927,949	$ 1,086,157	$ 577,562	$ 823,523	$ 303,855	$ (1,047)	$ 4,476,672
34	Fcst Direct Gas Costs(Incl U/G Hedge	ln 13		577,491	564,695	534,977	575,570	548,477	529,913	8,571,066	14,295,955	17,810,177	15,026,671	12,088,564	7,028,056	-	78,151,613
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	294,918	294,918	294,918	294,918	294,918	294,918	-	1,769,508
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(3,404,642)	(12,598,306)	(17,036,563)	(17,397,822)	(14,914,523)	(10,436,213)	(3,858,513)	(79,646,582)
37	Projected Unbilled Revenue									(6,949,727)	(9,708,586)	(11,207,370)	(8,821,855)	(6,754,086)	(3,858,513)		(47,300,137)
38	Reverse Prior Month Unbilled										6,949,727	9,708,586	11,207,370	8,821,855	6,754,086	3,858,513	47,300,137
39	Add Net Adjustments	ln 19		(58,562)	(531,514)	(154,684)	(65,205)	(114,261)	(29,138)	57,834	(79,660)	(80,638)	(65,068)	(57,951)	(87,642)	-	(1,266,487)
40	Gas Cost Billed	ln 20	(3,541,223)		-	-	-	-	-	-	-	-	-	-	-	-	(3,541,223)
41	Add Interest	ln 26			-	-	-	-	-	7,052	4,191	2,365	1,840	1,689	555	-	17,691
42	**(Over)/Under Balance**		$ 935,450	$ 1,454,378	$ 1,495,745	$ 1,879,990	$ 2,395,020	$ 2,835,143	$ 3,342,912	$ 1,927,950	$ 1,086,188	$ 577,631	$ 823,616	$ 303,988	$ (897)	$ (1,047)	$ (38,808)
44	Average Monthly Balance			$ 2,965,525	$ 1,479,155	$ 1,689,843	$ 2,139,837	$ 2,618,034	$ 3,092,524	$ 2,639,699	$ 1,507,068	$ 831,894	$ 700,589	$ 563,755	$ 151,479	$ (1,047)	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		8,186	3,951	4,664	5,907	6,993	8,536	7,051	4,160	2,296	1,747	1,556	405	-	55,452
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 935,450	$ 1,462,564	$ 1,499,697	$ 1,884,654	$ 2,400,926	$ 2,842,136	$ 3,351,448	$ 1,927,949	$ 1,086,157	$ 577,562	$ 823,523	$ 303,855	$ (1,047)	$ (1,047)	(1,047)
51	Forecast Sendout Therms	Sch 1								11,232,954	16,660,245	20,108,101	16,286,125	13,936,821	8,180,475		86,404,722
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								3,602,796	13,331,541	18,028,109	18,410,394	15,782,564	11,043,611	4,083,082	84,282,098
53	Less Forecast Unaccounted For	Sch 1								166,500	246,946	298,052	241,401	206,579	121,255		1,280,734
54	Less Forecast Company Use	Sch 1								109,449	162,330	195,925	158,685	135,794	79,707		841,891
55	Unbilled Volumes									7,354,208	2,919,427	1,586,015	-2,524,355	-2,188,116	-3,064,099	-4,083,082	(0)
56	Gross Unbilled									7,354,208	10,273,636	11,859,651	9,335,297	7,147,181	4,083,082	0	
59	COB w/o Interest	Sch. 3, pg. 4, ln 210 col. (c)								$0.9443	$0.9443	$0.9443	$0.9443	$0.9443	$0.9443	$0.9443	
61	COG With Interest	Sch. 3, pg. 4, ln 210 col. (d)								$0.9450	$0.9450	$0.9450	$0.9450	$0.9450	$0.9450	$0.9450	

65 1/ Beginning Balance for Acct 175.20. See Tab 18, Schedule 1, page 1, line 30, April 2008 column.
66 2/ Gas Cost Billed Acct 175.20. See Tab 18, Schedule 1, page 1, line 14, May 2008 column.

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

71			Prior Period Balance														
72			Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Peak Period
73		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
74	(a)	(b)	Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
75																	
76	**Accunt 142.20 Working Capital (Over)/Under Balance - Interest Calculation**																
77																	
78	**Beginning Balance**	Account 142.20 1/	**$ (49,400)**	$ (63,719)	$ (62,229)	$ (61,223)	$ (60,588)	$ (60,223)	$ (59,875)	$ (59,549)	$ (53,016)	$ (41,803)	$ (27,706)	$ (15,718)	$ (6,140)	$ (566)	$ (49,400)
79																	
80	Days Lag						10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18		
81	Prime Rate						3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
82	Forecast Working Capital	ln 34 * 0.00391		1,643	1,171	803	522	497	480	7,769	12,958	16,144	13,621	10,958	6,370	-	72,936
83																	
84	Projected Revenues w/o Int.	ln 121 * ln 124		-	-	-	-	-	-	(360)	(1,333)	(1,803)	(1,841)	(1,578)	(1,104)	(408)	(8,428)
85	Projected Unbilled Revenue									(735)	(1,027)	(1,186)	(934)	(715)	(408)		(5,005)
86	Reverse Prior Month Unbilled										735	1,027	1,186	934	715	408	5,005
87																	
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
89																	
90	Working Capital Billed	Account 142.20 2/	(14,319)														(14,319)
91																	
92	Monthly (Over)/Under Recovery		$ (63,719)	$ (62,076)	$ (61,058)	$ (60,420)	$ (60,056)	$ (59,715)	$ (59,385)	$ (52,866)	$ (41,672)	$ (27,611)	$ (15,664)	$ (6,110)	$ (557)	$ (566)	$ 790
93																	
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ (55,738)	$ (61,644)	$ (60,822)	$ (60,322)	$ (59,969)	$ (59,630)	$ (56,208)	$ (47,344)	$ (34,707)	$ (21,685)	$ (10,914)	$ (3,348)	$ (566)	
95																	
96	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
97																	
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ (154)	$ (165)	$ (168)	$ (167)	$ (160)	$ (165)	$ (150)	$ (131)	$ (96)	$ (54)	$ (30)	$ (9)	$ -	$ (1,447)
99																	
100	**(Over)/Under Balance**	ln 92 + ln 98	$ (63,719)	$ (62,229)	$ (61,223)	$ (60,588)	$ (60,223)	$ (59,875)	$ (59,549)	$ (53,016)	$ (41,803)	$ (27,706)	$ (15,718)	$ (6,140)	$ (566)	$ (566)	(658)
101																	
102																	
103	**Calculation of Working Capital with Interest**																
104																	
105	**Beginning Balance**	ln 78	$ (49,400)	$ (63,719)	$ (62,229)	$ (61,223)	$ (60,588)	$ (60,233)	$ (59,896)	$ (59,580)	$ (53,057)	$ (41,855)	$ (27,769)	$ (15,791)	$ (6,223)	$ (660)	$ (49,400)
106	Forecast Working Capital	ln 82		1,643	1,171	803	522	497	480	7,769	12,958	16,144	13,621	10,958	6,370	-	72,936
107	Projected Rev. with interest	ln 121 * ln 126		-	-	-	-	-	-	(360)	(1,333)	(1,803)	(1,841)	(1,578)	(1,104)	(408)	(8,428)
108	Projected Unbilled Revenue									(735)	(1,027)	(1,186)	(934)	(715)	(408)		(5,005)
109	Reverse Prior Month Unbilled										735	1,027	1,186	934	715	408	5,005
110	Add Net Adjustments	ln 88		-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	(14,319)	-	-	-	-	-	-								(14,319)
112	Add Interest	ln 98		-	-	-	-	-	-	(150)	(131)	(96)	(54)	(30)	(9)	-	(470)
113	Monthly (Over)/Under Recovery		$ (63,719)	$ (62,076)	$ (61,058)	$ (60,420)	$ (60,066)	$ (59,736)	$ (59,416)	$ (53,057)	$ (41,855)	$ (27,768)	$ (15,791)	$ (6,223)	$ (659)	$ (660)	$ 320
114																	
115	Average Monthly Balance			$ (55,738)	$ (61,644)	$ (60,822)	$ (60,327)	$ (59,984)	$ (59,656)	$ (56,319)	$ (47,456)	$ (34,812)	$ (21,780)	$ (11,007)	$ (3,441)	$ (660)	
116																	
117	Interest Applied	ln 96 * ln 115 / 365 * Days of Month		(154)	(165)	(168)	(167)	(160)	(165)	(150)	(131)	(96)	(54)	(30)	(9)	-	$ (1,449)
118																	
119	**(Over)/Under Balance**	-ln 112 +ln 113 + ln 117	$ (63,719)	$ (62,229)	$ (61,223)	$ (60,588)	$ (60,233)	$ (59,896)	$ (59,580)	$ (53,057)	$ (41,855)	$ (27,769)	$ (15,791)	$ (6,223)	$ (660)	$ (660)	$ (660)
120																	
121	Forecast Therm Sales	ln 52								3,602,796	13,331,541	18,028,109	18,410,394	15,782,564	11,043,611	4,083,082	84,282,098
122	Unbilled Therm	ln 55								7,354,208	2,919,427	1,586,015	(2,524,355)	(2,188,116)	(3,064,099)		
123	Gross Unbilled									7,354,208	10,273,636	11,859,651	9,335,297	7,147,181	4,083,082		
123																	
124	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 227 col. (c)								$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	
125																	
126	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 227 col. (d)								$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	

127 1/ Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 15, April 2008 column.
128 2/ Working Capital Billed Acct 142.20. See Tab 18, Schedule 5, page 1, line 3, May 2008 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line	(a)	(b)	Prior Period Balance Apr-09 Ending Bal Plus May Collections	May-09 (c)	Jun-09 (d)	Jul-09 (e)	Aug-09 (f)	Sep-09 (g)	Oct-09 (h)	Nov-09 (i)	Dec-09 (j)	Jan-10 (k)	Feb-10 (l)	Mar-10 (m)	Apr-10 (n)	May-10 (o)	DemandPeriod Total (p)
131		Days in Month		31	30	31	31	30	31	30	31	31	28	31	30	31	
133																	
134	**Accunt 175.52 Bad Debt (Over)/Under Balance - Interest Calculation**																
135																	
136	Forecast Direct Gas Costs	ln 34		$ 577,491	$ 564,695	$ 534,977	$ 575,570	$ 548,477	$ 529,913	$ 8,571,066	$ 14,295,955	$ 17,810,177	$ 15,026,671	$ 12,088,564	$ 7,028,056	$ -	78,151,613
137	Forecast Working Capital	ln 105		1,643	1,171	803	522	497	480	(55,949)	12,958	16,144	13,621	10,958	6,370		9,218
138	Prior Period Balance	ln 42								155,908	155,908	155,908	155,908	155,908	155,908		935,450
139	Total Forecast Direct Gas Costs & Working Capital			579,134	565,866	535,780	576,092	548,974	530,394	8,671,025	14,464,822	17,982,229	15,196,200	12,255,429	7,190,335	-	78,160,830
140																	
141	**Beginning Balance**	Account 175.52 1/	$ (194,262)	$ (212,161)	$ (197,991)	$ (184,128)	$ (171,009)	$ (156,828)	$ (143,284)	$ (130,189)	$ (143,695)	$ (122,801)	$ (84,118)	$ (36,658)	$ (15,003)	$ (2,355)	$ (194,262)
142																	
143	Forecast Bad Debt	ln 139 * 0.0254		14,710	14,373	13,609	14,633	13,944	13,472	220,244	367,406	456,749	385,983	311,288	182,634		2,009,046
144																	
145	Projected Revenues w/o int	ln 182 * ln 186		-	-	-	-	-	-	(76,740)	(283,962)	(383,999)	(392,141)	(336,169)	(235,229)	(86,970)	(1,795,209)
146	Projected Unbilled Revenue									(156,645)	(218,828)	(252,611)	(198,842)	(152,235)	(86,970)		(1,066,130)
147	Reverse Prior Month Unbilled										156,645	218,828	252,611	198,842	152,235	86,970	1,066,130
148																	
149	Bad Debt Billed	Account 175.52 2/	(17,899)		-	-	-	-	-		-	-	-	-	-	-	(17,899)
150																	
151	Add Net Adjustments			-	-	-	-	-	-		-	-	-	-	-	-	-
152																	
153	Monthly (Over)/Under Recovery		$ (212,161)	$ (197,451)	$ (183,618)	$ (170,519)	$ (156,376)	$ (142,884)	$ (129,812)	$ (143,329)	$ (122,434)	$ (83,833)	$ (36,508)	$ (14,932)	$ (2,332)	$ (2,355)	$ 1,676
154																	
155	Average Monthly Balance	(ln 141 + ln 153)/2		$ (195,856)	$ (190,805)	$ (177,324)	$ (163,692)	$ (149,856)	$ (136,548)	$ (136,759)	$ (133,064)	$ (103,317)	$ (60,313)	$ (25,795)	$ (8,668)	$ (2,355)	
156																	
157	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
158																	
159	Interest Applied	ln 155 * ln 157 / 365 * Days of Month		$ (541)	$ (510)	$ (489)	$ (452)	$ (400)	$ (377)	$ (365)	$ (367)	$ (285)	$ (150)	$ (71)	$ (23)		$ (4,031)
160																	
161	**(Over)/Under Balance**	ln 153 + ln 159	$ (212,161)	$ (197,991)	$ (184,128)	$ (171,009)	$ (156,828)	$ (143,284)	$ (130,189)	$ (143,695)	$ (122,801)	$ (84,118)	$ (36,658)	$ (15,003)	$ (2,355)	$ (2,355)	(2,355)
162																	
163																	
164	**Calculation of Bad Debt with Interest**																
165																	
166	**Beginning Balance**	ln 141	$ (194,262)	$ (212,161)	$ (197,991)	$ (184,128)	$ (171,009)	$ (156,828)	$ (143,284)	$ (130,189)	$ (143,695)	$ (122,802)	$ (84,119)	$ (36,659)	$ (15,004)	$ (2,356)	$ (194,262)
167	Forecast Bad Debt	ln 143		14,710	14,373	13,609	14,633	13,944	13,472	220,244	367,406	456,749	385,983	311,288	182,634	-	2,009,046
168	Projected Revenues with int.	ln 182 * ln 188		-	-	-	-	-	-	(76,740)	(283,962)	(383,999)	(392,141)	(336,169)	(235,229)	(86,970)	(1,795,209)
169	Projected Unbilled Revenue									(156,645)	(218,828)	(252,611)	(198,842)	(152,235)	(86,970)		(1,066,130)
170	Reverse Prior Month Unbilled										156,645	218,828	252,611	198,842	152,235	86,970	1,066,130
171	Bad Debt Billed	ln 149	(17,899)		-	-	-	-	-	-	-	-	-	-	-	-	(17,899)
172	Add Interest	ln 159		-	-	-	-	-	-	(365)	(367)	(285)	(150)	(71)	(23)	-	(1,263)
173	Add Net Adjustments	ln 151								-	-	-	-	-	-	-	0
174	Monthly (Over)/Under Recovery		$ (212,161)	$ (197,451)	$ (183,618)	$ (170,519)	$ (156,376)	$ (142,884)	$ (129,812)	$ (143,695)	$ (122,801)	$ (84,119)	$ (36,659)	$ (15,004)	$ (2,356)	$ (2,356)	$ 414
175																	
176	Average Monthly Balance			$ (195,856)	$ (190,805)	$ (177,324)	$ (163,692)	$ (149,856)	$ (136,548)	$ (136,942)	$ (133,248)	$ (103,461)	$ (60,389)	$ (25,831)	$ (8,680)	$ (2,356)	
177																	
178	Interest Applied	ln 157 * ln 176 / 365 * Days of Month		(541)	(510)	(489)	(452)	(400)	(377)	(366)	(368)	(285)	(150)	(71)	(23)	-	$ (4,032)
179																	
180	**(Over)/Under Balance**	-ln 172 +ln 174 + ln 178	$ (212,161)	$ (197,991)	$ (184,128)	$ (171,009)	$ (156,828)	$ (143,284)	$ (130,189)	$ (143,695)	$ (122,802)	$ (84,119)	$ (36,659)	$ (15,004)	$ (2,356)	$ (2,356)	$ (2,356)
181																	
182	Forecast Term Sales	ln 52								3,602,796	13,331,541	18,028,109	18,410,394	15,782,564	11,043,611	4,083,082	84,282,098
183	Unbilled Therm	ln 55								7,354,208	2,919,427	1,586,015	(2,524,355)	(2,188,116)	(3,064,099)		
184	Gross Unbilled									7,354,208	10,273,636	11,859,651	9,335,297	7,147,181	4,083,082		
185																	
186	COG Rate Without Interest	Sch. 3, pg. 4, ln 244 col. (c)								$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	
187																	
188	COG With Interest	Sch. 3, pg. 4, ln 244 col. (d)								$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	

189 1/ Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 19, April 2008 column.
190 2/ Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 9, May 2008 column.
191

Line	(a)	(b)	Prior Period	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Total
192	**Total Interest**	lns 46 + 117 + 178	$ -	$ 7,491	$ 3,277	$ 4,007	$ 5,288	$ 6,433	$ 7,995	$ 6,535	$ 3,661	$ 1,915	$ 1,542	$ 1,455	$ 372	$ -	$ 49,971

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

193				
			COG Rate Without Interest	COG Rate With Interest
194	**Calculation of COG**			
195	(a)	(b)	(c)	(d)
196	(Over)Under Recovery Balance	In 12, col. (q)	$ 4,476,672	$ 4,476,672
197				
198	Unadjusted Forecast of Gas Costs	In 13, col. (q)	78,151,613	78,151,613
199				
200	Production & Storage and Misc Overh	In 14, col. (q)	1,769,508	1,769,508
201				
202	Adjustments	In 19, col. (q)	(4,807,710)	(4,807,710)
203				
204	Interest Nov -Apr	In 26, col. (q)	-	$ 55,452
205				
206	Total Gas To Be Recovered		$ 79,590,083	$ 79,645,535
207				
208	Forecast Gas Sales (May - Oct)	In 52, col. (q)	84,282,098	84,282,098
209				
210	Preliminary COG Rate	In. 227 / In. 229	$0.9443	$0.9450
211				
212				
			Working Capital Rate without interest	Working Capital Rate with Interest
213	**Calculation of Working Capital Rate**			
214	(a)	(b)	(c)	(d)
215	(Over)Under Recovery Balance	In 78, col. (q)	$ (49,400)	$ (49,400)
216				
217	Unadjusted Working Capital Forecast	In 82, col. (q)	72,936	72,936
218				
219	Adjustments without interest	In 88, col. (q)	(14,319)	(14,319)
220				
221	Interest (May - Oct)	In 98, col. (q)	-	$ (1,449)
222				
223	Total Gas To Be Recovered		$ 9,218	$ 7,769
224				
225	Forecast Gas Sales	In 52, col. (q)	84,282,098	84,282,098
226				
227	Preliminary Working Capital COG Rate		$0.0001	$0.0001
228				
229				
			Bad Debt Rate without Interest	Bad Debt Rate with interest
230	**Calculation of Bad Debt Rate**			
231	(a)	(b)	(c)	
232	(Over)Under Recovery Balance	In 141, col. (q)	$ (194,262)	$ (194,262)
233				
234	Unadjusted Bad Debt Forecast	In 143, col. (q)	2,009,046	2,009,046
235				
236	Adjustments without interest	In 151, col. (q)	(17,899)	(17,899)
237				
238	Interest (May - Oct)	In 159, col. (q)	-	$ (4,032)
239				
240	Total Gas To Be Recovered		$ 1,796,885	$ 1,792,852
241				
242	Forecast Gas Sales (May - Oct)	In 52, col. (q)	84,282,098	84,282,098
243				
244	Preliminary Bad Debt COG Rate		$0.0213	$0.0213

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

Line	Adjustments		Prior Period Adjustments	Refunds from Suppliers	Broker Revenue	Inventory Finance Charges	Transportation CGA Revenues (Schedule 17)	Interruptible Sales Margin	Off System Sales Margin	Capacity Release	COG Hedging Costs	Fixed Price Option Administrative Costs	Total Adjustments
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8													
9	May-09		$ -	$ -	$ (23,679)	$ 9,945	$ -				$ -	$ -	$ (58,562)
10	Jun-09		-	-	(486,550)	9,018	-				-	-	(531,514)
11	Jul-09		-	-	(24,288)	5,942	-				-	-	(154,684)
12	Aug-09	1/	-	-	(529)	18,270	-				-	-	(65,205)
13	Sep-09	1/	-	-	(54,347)	18,339	-				-	-	(114,261)
14	Oct-09	1/	-	-	(33,007)	35,857	-				-	-	(29,138)
15	Nov-09	1/	-	-	(38,655)	55,301	1,045				-	40,691	57,834
16	Dec-09	1/	-	-	(53,914)	22,727	1,238				-	-	(79,660)
17	Jan-10	1/	-	-	(65,671)	15,680	1,713				-	-	(80,638)
18	Feb-10	1/	-	-	(37,927)	7,357	1,694				-	-	(65,068)
19	Mar-10	1/	-	-	(33,585)	6,378	1,637				-	-	(57,951)
20	Apr-10	1/	-	-	(38,457)	5,491	1,328				-	-	(87,642)
21													
22	Subtotal May 09 - Oct 09		$ -	$ -	$ (622,400)	$ 97,371	$ -	$ -	$ (73,523)	$ (354,811)	$ -	$ -	$ (953,362)
23													
24	Subtotal Nov 09 - Apr 10		$ -	$ -	$ (268,209)	$ 112,933	$ 8,654	$ -	$ (28,322)	$ (178,872)	$ -	$ 40,691	$ (313,125)
25													
26	Total Peak Period		$ -	$ -	$ (890,609)	$ 210,305	$ 8,654	$ -	$ (101,845)	$ (533,683)	$ -	$ 40,691	$ (1,266,487)
27													

1/ Estimate is based on prior years actual. Exception: Transportation Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 09 - Apr 10 calculated on Schedule 16.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Demand Costs**

Ln	(a)	Peak (b)	Reference (c)	Peak Costs May 09 -Oct 09 (d)	Nov-09 (e)	Dec-09 (f)	Jan-10 (g)	Feb-10 (h)	Mar-10 (i)	Apr-10 (j)	Peak May -Apr Total (k)
5											
6											
7											
8											
9											
10											
11	**Supply**										
12	Niagra Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days								
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days								
17	Tenn Gas Pipeline 33371		Sch 5B, ln 13 * Sch 5C ln 16 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 18 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 20 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 22 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 24 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 26 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 28 x days								
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 30 x days								
25	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 21 * Sch 5C ln 46 x days								
26	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 22 * Sch 5C ln 32 x days								
27	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 23 * Sch 5C ln 34 x days								
28	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 24 * Sch 5C ln 36 x days								
29	National Fuel FST 2358	peak	Sch 5B, ln 25 * Sch 5C ln 38 x days								
30											
31	Subtotal Pipeline Demand Charges			$ 970,611	$ 790,177	$ 790,177	$ 790,177	$ 790,177	$ 790,177	$ 790,177	$ 5,711,673
32											
33	**Peaking Supply**										
34	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 28 * Sch 5C ln 28 x days								
35	Granite Ridge Demand	peak	Sch 5B, ln 29 * Sch 5C ln 49 x days								
36	DOMAC Demand FLS-160	peak	Per 08-09 Contract								
37	Subtotal Peaking Demand Chargs			$ 120,000	$ 397,864	$ 397,864	$ 397,864	$ 397,864	$ 397,864	$ 324,250	$ 2,433,569
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 1,090,611	$ 1,188,857	$ 1,188,884	$ 1,188,884	$ 1,188,802	$ 1,188,884	$ 1,115,243	$ 8,150,164
40											
41	Less Transportation Capacity Credit			$ (173,342)	$ (177,998)	$ (178,002)	$ (178,002)	$ (177,990)	$ (178,002)	$ (166,977)	$ (1,230,314)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 917,269	$ 1,010,858	$ 1,010,881	$ 1,010,881	$ 1,010,812	$ 1,010,881	$ 948,266	$ 6,919,850
44											
45	**Storage**										
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 53 x days	$ 10,544	$ 1,757	$ 1,757	$ 1,757	$ 1,757	$ 1,757	$ 1,757	21,088
47	Dominion - Storage	peak	Sch 5B, ln 34 * Sch 5C ln 54 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
48	Honeoye - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 57 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
49	National Fuel - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 59 x days	78,869	13,145	13,145	13,145	13,145	13,145	13,145	157,738
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 60 x days	173,871	28,979	28,979	28,979	28,979	28,979	28,979	347,743
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 63 x days	150,724	25,121	25,121	25,121	25,121	25,121	25,121	301,447
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 64 x days	173,203	28,867	28,867	28,867	28,867	28,867	28,867	346,407
53											
54	**Subtotal Storage Demand Costs**			$ 648,613	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 108,102	$ 1,297,225
55											
56	Less Transportation Capacity Credit			$ (103,091)	$ (16,185)	$ (16,185)	$ (16,185)	$ (16,185)	$ (16,185)	$ (16,185)	$ (200,202)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 545,522	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 91,917	$ 1,097,023
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 1,739,223	$ 1,296,959	$ 1,296,986	$ 1,296,986	$ 1,296,904	$ 1,296,986	$ 1,223,345	$ 9,447,389
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (276,432)	$ (194,184)	$ (194,188)	$ (194,188)	$ (194,175)	$ (194,188)	$ (183,162)	$ (1,430,516)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,462,791	$ 1,102,775	$ 1,102,798	$ 1,102,798	$ 1,102,729	$ 1,102,798	$ 1,040,183	$ 8,016,873
65											

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Demand Volumes

		Peak	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply									
	Niagra Supply			3,199	3,199	3,199	3,199	3,199	3,199
Pipeline									
	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline		33371	4,000	4,000	4,000	4,000	4,000	4,000
	Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
	Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
	Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
	Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
	Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Tenn Gas Pipeline (Concord Lateral)		Z6-Z6	5,000	5,000	5,000	5,000	5,000	5,000
	Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
	ANE (TransCanada via Union to Iroquois)		Union Dawn to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
	National Fuel	peak	FST 2358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking									
	Tenn Gas Pipeline (Concord Lateral)	peak		25,000	25,000	25,000	25,000	25,000	25,000
	Granite Ridge Demand	peak		15,000	15,000	15,000	15,000	15,000	15,000
	DOMAC Liquid Demand Charge	peak		6,300	6,300	6,300	6,300	6,300	0
Storage									
	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
	Honeoye - Capacity	peak	SS-NY	246,240	246,240	246,240	246,240	246,240	246,240
	National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
	National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
	Tenn Gas Pipeline - Demand	peak	FS-MA	21,844	21,844	21,844	21,844	21,844	21,844
	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Demand Rates

				Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Nov - Apr
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagra Supply										
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$6.5971	31st Rev Sheet No. 4	$0.2199	$0.2128	$0.2128	$0.2356	$0.2128	$0.2199	$0.2190
Tenn Gas Pipeline	33371 Segment 3	$5.0700	42nd Rev Sheet No. 26B	$0.1690	$0.1635	$0.1635	$0.1811	$0.1635	$0.1690	$0.1683
Tenn Gas Pipeline	33371 Segment 4	$5.5400	42nd Rev Sheet No. 26B	$0.1847	$0.1787	$0.1787	$0.1979	$0.1787	$0.1847	$0.1839
		$10.6100		$0.3537	$0.3423	$0.3423	$0.3789	$0.3423	$0.3537	$0.3522
Tenn Gas Pipeline	2302 Z5-Z6	$4.9300	26th Rev Sheet No. 23	$0.1643	$0.1590	$0.1590	$0.1761	$0.1590	$0.1643	$0.1636
Tenn Gas Pipeline	8587 Z0-Z6	$16.5900	26th Rev Sheet No. 23	$0.5530	$0.5352	$0.5352	$0.5925	$0.5352	$0.5530	$0.5507
Tenn Gas Pipeline	8587 Z1-Z6	$15.1500	26th Rev Sheet No. 23	$0.5050	$0.4887	$0.4887	$0.5411	$0.4887	$0.5050	$0.5029
Tenn Gas Pipeline	8587 Z4-Z6	$5.8900	26th Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
TGP Dracut	42076 FTA Z6-Z6	$3.1600	26th Rev Sheet No. 23	$0.1053	$0.1019	$0.1019	$0.1129	$0.1019	$0.1053	$0.1049
TGP Concord Lateral	Z6-Z6		per contract							
Portland Natural Gas	FT-1999-001	$27.4017	6th Rev Sheet No. 100	$0.9134	$0.8839	$0.8839	$0.9786	$0.8839	$0.9134	$0.9095
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$5.8900	26th Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$5.8900	26th Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$4.9300	26th Rev Sheet No. 23	$0.1643	$0.1590	$0.1590	$0.1761	$0.1590	$0.1643	$0.1636
National Fuel	FST 2358	$3.3612	129th Rev Sheet No. 9	$0.1120	$0.1084	$0.1084	$0.1200	$0.1084	$0.1120	$0.1116
ANE TransCanada PipeLines Limited		$7.7283	Union Dawn to Iroquois							
Delivery Pressure Demand Charge		0.5630	Union Dawn to Iroquois							
Sub Total Demand Charges		8.2913								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		0.9228	08/07/2009							
Demand Rate/US$		$8.0728		$0.2691	$0.2604	$0.2604	$0.2883	$0.2604	$0.2691	$0.2680
Peaking										
Granite Ridge Demand			per contract							
Storage										
Dominion - Demand	GSS 300076	$1.8815	33rd Rev Sheet No. 35	$0.0627	$0.0607	$0.0607	$0.0672	$0.0607	$0.0627	$0.0624
Dominion - Capacity	GSS 300076	$0.0145	33rd Rev Sheet No. 35	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8960		$0.0632	$0.0612	$0.0612	$0.0677	$0.0612	$0.0632	$0.0629
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet 5	$0.2140	$0.2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
National Fuel - Demand	FSS-1 2357	$2.1556	16th Rev. Sheet No. 10	$0.0719	$0.0695	$0.0695	$0.0770	$0.0695	$0.0719	$0.0715
National Fuel - Capacity	FSS-1 2357	$0.0432	16th Rev. Sheet No. 10	$0.0014	$0.0014	$0.0014	$0.0015	$0.0014	$0.0014	$0.0014
		$2.1988		$0.0733	$0.0709	$0.0709	$0.0785	$0.0709	$0.0733	$0.0729
Tenn Gas Pipeline	FS-MA	$1.1500	17th Rev Sheet No. 27	$0.0383	$0.0371	$0.0371	$0.0411	$0.0371	$0.0383	$0.0381
Tenn Gas Pipeline - Space	FS-MA	$0.0185	17th Rev Sheet No. 27	$0.0006	$0.0006	$0.0006	$0.0007	$0.0006	$0.0006	$0.0006
		$1.1685		$0.0390	$0.0377	$0.0377	$0.0417	$0.0377	$0.0390	$0.0388

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APPLICABLE TO SETTLING PARTIES PURSUANT TO THE MARCH 29, 2005, STIPULATION
IN DOCKET NOS. RP97-406, RP00-15, RP00-344 and RP00-632
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE SHEET 35A)

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
===	Storage Demand	$1.7984	$0.0670	$0.0202	($0.0057)	$0.0016	-	$1.8815
	Storage Capacity	$0.0145	-	-	-	-	-	$0.0145
	Injection Charge	$0.0154	-	$0.0070	$0.0002	$0.0004	-	$0.0230
	Withdrawal Charge	$0.0154	-	-	$0.0002	$0.0004	$0.0017	$0.0177
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0004	-	-	$0.0050
	Demand Charge Adjustment	$21.5808	$0.8040	$0.2424	($0.0684)	$0.0192	-	$22.5780
	From Customers Balance	$0.6163	$0.0147	$0.0044	($0.0010)	$0.0008	$0.0017	$0.6369
GSS-E [2], [4]								
===	Storage Demand	$2.2113	$0.0670	$0.0202	($0.0057)	$0.0016	-	$2.2944
	Storage Capacity	$0.0369	-	-	-	-	-	$0.0369
	Injection Charge	$0.0154	-	$0.0070	$0.0002	$0.0004	-	$0.0230
	Withdrawal Charge	$0.0154	-	-	$0.0002	$0.0004	$0.0017	$0.0177
	Authorized Overruns	$1.0657	$0.0147	$0.0044	($0.0010)	$0.0008	$0.0017	$1.0863
ISS [2]								
======	ISS Capacity	$0.0736	$0.0022	$0.0007	($0.0002)	$0.0001	-	$0.0764
	Injection Charge	$0.0154	-	$0.0070	$0.0002	$0.0004	-	$0.0230
	Withdrawal Charge	$0.0154	-	-	$0.0002	$0.0004	$0.0017	$0.0177
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0147	$0.0044	($0.0010)	$0.0008	$0.0017	$0.6369
	Excess Injection Charge	$0.2245	-	$0.0070	$0.0002	$0.0004	-	$0.2321

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.28% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 2.56%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6192.
Daily Capacity Release Rate for GSS-E per DT is $1.0686
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.

Issued by: Anne E. Bomar, Vice President - Federal Regulation
Issued on: November 3, 2008 Effective on: December 4, 2008
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. CP05-130-000, et al., issued October 7, 2008, 25 FERC ? 61,018

subject to an allowable variation of not more than one percent above or below the aggregate of said scheduled daily deliveries of said month.

The amount of gas in storage for Buyer's account at any time (exclusive of Buyer's share of cushion gas) shall be Buyer's Gas Storage Balance at that time and shall not exceed Buyer's Maximum Quantity Stored (MQS).

Seller shall be ready at all times to deliver to Buyer, and Buyer shall have the right at all times to receive from Seller, natural gas up to the MDWQ Seller is obligated to deliver to Buyer on that day.

Buyer's MQS, Buyer's MDWQ and Buyer's ADWQ shall be specified in the Gas Storage Agreement providing for service under this Rate Schedule.

3. RATE

Buyer shall pay Seller for each month of the year during the term of the Gas Storage Agreement a Demand Charge which shall be six dollars and forty one point eight seven cents per MMBTU ($6.4187/MMBTU)** multiplied by the ADWQ as provided for in the Gas Storage Agreement.

4. MINIMUM BILL

The Minimum Bill for each month shall consist of the Demand Charge for the ADWQ as defined in Article 3.

5. COMPRESSOR FUEL ALLOWANCE

Buyer will make available without charge to Seller such additional quantities of gas as needed by Seller for

** The Demand Charge Rate set forth in individual service agreements shall be deemed to have been converted to a thermal billing basis utilizing a factor of 1022/MMBTU per 1 MCF as adjusted pursuant to Section III of the General Terms & Conditions, provided however, the total Maximum Quantity Stored in the field shall not exceed 4.8 BCF and provided that each Buyer shall receive its allowable share of same.

--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	------------------ Settlement Recourse Rates --------------------- ---- Applicable to Non-Eastchester/Non-Contesting Shippers 2/ ---- Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

Rate Sch. (1)	Rate Component (2)		Base Rate (3)	FERC ACA (4)	Current Rate 1/ (5)
IT	Commodity	(Max)	$0.1168	0.0017	$0.1185
		(Min)	0.0000	0.0017	$0.0017
	Overrun	(Max)	0.1168	0.0017	$0.1185
		(Min)	0.0000	0.0017	$0.0017
IG	Commodity	(Max)	0.2200	-	$0.2200
		(Min)	0.0069	-	$0.0069
FG	Reservation	(Max)	0.0000	-	$0.0000
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0069	0.0017	$0.0086
		(Min)	0.0069	0.0017	$0.0086
	Overrun	(Max)	0.2200	0.0017	$0.2217
		(Min)	0.2200	0.0017	$0.2217
X-58 Conversion Surcharge					
	Reservation	(Max)	0.1221	-	$0.1221
		(Min)	-	-	-
	Commodity	(Max)	-	-	-
		(Min)	-	-	-
W-1	Commodity	(Max)	0.0252	0.0017	$0.0269
		(Min)	0.0000	-	$0.0000
	Overrun	(Max)	0.0252	0.0017	$0.0269
		(Min)	0.0000	-	$0.0000
	Fly-By Rate	(Max)	0.0100	-	$0.0100
		(Min)	0.0000	-	$0.0000
IR-1	First Day	(Max)	0.0532	0.0017	$0.0549
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0028	-	$0.0028
	Day	(Min)	0.0000	-	$0.0000
IR-2	First Day	(Max)	0.0028	-	$0.0028
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0028	-	$0.0028
	Day	(Min)	0.0000	-	$0.0000
FST	Reservation	(Max)	3.3612	-	$3.3612
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0063	0.0017	$0.0080
		(Min)	0.0063	0.0017	$0.0080
	Overrun	(Max)	0.1168	0.0017	$0.1185
		(Min)	0.0063	0.0017	$0.0080
	Maximum Volumetric Rate		0.1168	0.0017	$0.1185

1/ All rates exclusive of Fuel and Company Use retention and Transportation LAUF retention. Fuel and Company Use retention for all applicable rate schedules is 1.15%. Transportation LAUF retention for all applicable rate schedules is 0.25%. Transporter may from time to time identify point pair transactions where the Fuel and Company Use retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the Transportation LAUF retention of 0.25%.

Rate Sch. (1)	Rate Component (2)			Base Rate (3)	FERC ACA (4)	Current Rate 2/ (5)
ESS	Demand	(Max)		$2.1345	-	$2.1345
		(Min)		0.0000	-	$0.0000
	Capacity	(Max)		0.0432	-	$0.0432
		(Min)		0.0000	-	$0.0000
	Injection/	(Max)		0.0139	0.0017	$0.0156
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/			0.0702	0.0017	$0.0719
	Max. Volumetric Cap. Rate 4/			0.0014	-	$0.0014
	Storage Balance Transfer	(Max)	5/	3.8600	-	$3.8600
		(Min)	5/	0.0000	-	$0.0000
ISS	Injection	(Max)		1.0635	0.0017	$1.0652
		(Min)		0.0000	-	$0.0000
	Storage Balance Transfer	(Max)	5/	3.8600	-	$3.8600
		(Min)	5/	0.0000	-	$0.0000
IAS	Usage	(Max)	1/	0.0028	-	$0.0028
		(Min)	1/	0.0000	-	$0.0000
	Advance/Return	(Max)		0.0139	0.0017	$0.0156
		(Min)		0.0000	-	$0.0000
FSS	Demand	(Max)		2.1556	-	$2.1556
		(Min)		0.0000	-	$0.0000
	Capacity	(Max)		0.0432	-	$0.0432
		(Min)		0.0000	-	$0.0000
	Injection/	(Max)		0.0139	0.0017	$0.0156
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/			0.0709	0.0017	$0.0726
	Max. Volumetric Cap. Rate 4/			0.0014	-	$0.0014
	Storage Balance Transfer	(Max)	5/	3.8600	-	$3.8600
		(Min)	5/	0.0000	-	$0.0000
P-1	First Day	(Max)		0.0575	0.0017	$0.0592
		(Min)		0.0000	-	$0.0000
	Each Subsequent	(Max)		0.0071	-	$0.0071
	Day	(Min)		0.0000	-	$0.0000
P-2	First Day	(Max)		0.0071	-	$0.0071
		(Min)		0.0000	-	$0.0000
	Each Subsequent	(Max)		0.0071	-	$0.0071
	Day	(Min)		0.0000	-	$0.0000

1/ Unit Dth Rates per day.
2/ All rates exclusive of Surface Operating Allowance and Storage LAUF retention, where applicable. Surface Operating Allowance for all applicable rate schedules is 1.17%. Storage LAUF retention for all applicable rate schedules is 0.23%.
3/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
4/ Assessed per dekatherm per day on storage balance.
5/ Rate per nomination.

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$27.4017	---------	$27.4017
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$52.0632	---------	$52.0632
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0017	$00.0017
	-- Minimum	$00.0000	$00.0017	$00.0017
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$18.3920	-------	$18.3920
	--Minimum	$00.0000	-------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.2962	$00.0017	$00.2979
	--Minimum	$00.0000	$00.0017	$00.0017

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum	down to -1.00%
Maximum	up to +1.00%

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 17 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

	RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
PCB Adjustment: 1/	0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	L		$0.00						
	1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-A Reservation Rate is $0.00 per Dth

Notes:
1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
2/ Maximum rates are inclusive of base rates and above surcharges.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/						
Segment U	$9.65			$0.00	$9.65	
Segment 1	$1.33			$0.00	$1.33	
Segment 2	$8.08			$0.00	$8.08	
Segment 3	$5.07			$0.00	$5.07	
Segment 4	$5.54			$0.00	$5.54	
Commodity Rate 2/, 3/						
Segments U, 1, 2, 3 & 4		$0.0017			$0.0017	6/
Extended Receipt and Delivery Rate 4/, 7/						
Segment U	$0.3173				$0.3173	5.52%
Segment 1	$0.0437				$0.0437	0.69%
Segment 2	$0.2656				$0.2656	0.59%
Segment 3	$0.1667				$0.1667	0.73%
Segment 4	$0.1821				$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 220A.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (TCSM) (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.02	$0.00	$2.02	
Space Rate	$0.0248	$0.0000	$0.0248	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	
Overrun Rate	$0.2427		$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.15	$0.00	$1.15	
Space Rate	$0.0185	$0.0000	$0.0185	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
Overrun Rate	$0.1380		$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA				
Space Rate	$0.0848	$0.0000	$0.0848	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA				
Space Rate	$0.0993	$0.0000	$0.0993	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

TransCanada
In business to deliver

Transportation Tolls
2009 Final Tolls Effective May 1st

1 **Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls**

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
2	Centra Gas Manitoba - MDA	2.34500	0.00462
3	Union Gas - WDA	16.66667	0.04509
4	Union Gas - NDA	6.45333	0.01622
5	Union Gas - EDA	4.22833	0.00964
6	Kingston PUC	4.06250	0.00908
7	Gaz Metropolitain - EDA	7.51000	0.01911
8	Enbridge - CDA	0.93583	0.00015
9	Enbridge - EDA	2.58833	0.00499
10	Cornwall	5.76167	0.01393
11	Philipsburg	7.58917	0.01914

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
12	ECR Surcharge	0.029

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
13	Emerson - 1 (Viking)	0.06426	0.00000	0.00211
14	Emerson - 2 (Great Lakes)	0.08446	0.00000	0.00278
15	Dawn	0.06286	0.00000	0.00207
16	Niagara Falls	0.10558	0.00000	0.00347
17	Iroquois	0.56297	0.00000	0.01851
18	Chippawa	0.61730	0.00000	0.02029
19	East Hereford	1.41498	0.02139	0.06791

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
2009 Final Tolls Effective May 1st
* These tolls will become effective on November 1, 2009

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	STFT Minimum Tolls (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% LF FT Tolls) ($/GJ)
1	Emerson 2	Napierville	25.40156	0.06991	0.9050	0.9955
2	Emerson 2	Philipsburg	25.58592	0.07044	0.9116	1.0028
3	Emerson 2	East Hereford	27.52555	0.07597	0.9809	1.0790
4	Union Dawn	Empress	28.28112	0.00000	0.9298	1.0228
5	Union Dawn	Transgas SSDA	24.33086	0.00000	0.7999	0.8799
6	* _Union Dawn_	_Transgas SSDA_	_24.82353_	_0.00000_	_0.8161_	_0.8977_
7	Union Dawn	Centram SSDA	21.86751	0.00000	0.7189	0.7908
8	Union Dawn	Centram MDA	19.03032	0.05218	0.6779	0.7457
9	Union Dawn	Centrat MDA	19.03776	0.05177	0.6777	0.7455
10	Union Dawn	Union WDA	18.74224	0.05102	0.6672	0.7339
11	Union Dawn	Nipigon WDA	16.73298	0.04520	0.5953	0.6548
12	Union Dawn	Union NDA	8.83255	0.02300	0.3134	0.3447
13	Union Dawn	Calstock NDA	13.26448	0.03532	0.4714	0.5185
14	Union Dawn	Tunis NDA	10.53372	0.02753	0.3738	0.4112
15	Union Dawn	GMIT NDA	8.49698	0.02156	0.3010	0.3311
16	Union Dawn	Union SSMDA	7.25587	0.01819	0.2567	0.2824
17	Union Dawn	Union NCDA	5.18095	0.01233	0.1826	0.2009
18	Union Dawn	Union CDA	3.30151	0.00680	0.1153	0.1268
19	Union Dawn	Enbridge CDA	3.98389	0.00880	0.1398	0.1538
20	Union Dawn	Union EDA	6.95563	0.01711	0.2458	0.2704
21	Union Dawn	Enbridge EDA	8.17713	0.02087	0.2897	0.3187
22	Union Dawn	GMIT EDA	9.88931	0.02589	0.3510	0.3861
23	Union Dawn	KPUC EDA	6.44157	0.01587	0.2277	0.2505
24	Union Dawn	North Bay Junction	7.02348	0.01753	0.2484	0.2732
25	Union Dawn	Enbridge SWDA	0.87529	0.00000	0.0288	0.0317
26	Union Dawn	Union SWDA	1.09017	0.00000	0.0358	0.0394
27	Union Dawn	Spruce	19.03776	0.05177	0.6777	0.7455
28	Union Dawn	Emerson 1	17.54958	0.00000	0.5770	0.6347
29	Union Dawn	Emerson 2	17.54958	0.00000	0.5770	0.6347
30	Union Dawn	St. Clair	1.12519	0.00000	0.0370	0.0407
31	Union Dawn	Dawn Export	0.87529	0.00000	0.0288	0.0317
32	Union Dawn	Kirkwall	2.85383	0.00564	0.0994	0.1093
33	Union Dawn	Niagara Falls	4.02646	0.00898	0.1414	0.1555
34	Union Dawn	Chippawa	4.05153	0.00905	0.1423	0.1565
35	Union Dawn	Iroquois	7.72830	0.01953	0.2736	0.3010
36	Union Dawn	Cornwall	8.14221	0.02071	0.2884	0.3172
37	Union Dawn	Napierville	9.78381	0.02539	0.3471	0.3818
38	Union Dawn	Philipsburg	9.96827	0.02592	0.3536	0.3890
39	Union Dawn	East Hereford	11.90791	0.03145	0.4230	0.4653
40	Enbridge CDA	Empress	31.70810	0.08792	1.1304	1.2434
41	Enbridge CDA	Transgas SSDA	27.83218	0.07467	0.9897	1.0887
42	* _Enbridge CDA_	_Transgas SSDA_	_28.32485_	_0.07609_	_1.0073_	_1.1080_
43	Enbridge CDA	Centram SSDA	24.85939	0.06833	0.8856	0.9742
44	Enbridge CDA	Centram MDA	22.42153	0.06187	0.7990	0.8789
45	Enbridge CDA	Centrat MDA	21.14728	0.05781	0.7531	0.8284
46	Enbridge CDA	Union WDA	16.43683	0.04444	0.5848	0.6433
47	Enbridge CDA	Nipigon WDA	14.65020	0.03987	0.5216	0.5738
48	Enbridge CDA	Union NDA	6.39952	0.01609	0.2265	0.2492
49	Enbridge CDA	Calstock NDA	11.34823	0.03072	0.4038	0.4442
50	Enbridge CDA	Tunis NDA	8.74845	0.02352	0.3111	0.3422
51	Enbridge CDA	GMIT NDA	6.37278	0.01463	0.2241	0.2465
52	Enbridge CDA	Union SSMDA	10.36446	0.02699	0.3677	0.4045
53	Enbridge CDA	Union NCDA	2.74487	0.00541	0.0956	0.1052
54	Enbridge CDA	Union CDA	1.87122	0.00258	0.0641	0.0705
55	Enbridge CDA	Enbridge CDA	0.87529	0.00000	0.0288	0.0317
56	Enbridge CDA	Union EDA	3.93145	0.00878	0.1381	0.1519
57	Enbridge CDA	Enbridge EDA	5.65768	0.01371	0.1997	0.2197
58	Enbridge CDA	GMIT EDA	7.19001	0.01822	0.2546	0.2801
59	Enbridge CDA	KPUC EDA	3.74248	0.00819	0.1312	0.1443
60	Enbridge CDA	North Bay Junction	4.58363	0.01060	0.1613	0.1774
61	Enbridge CDA	Enbridge SWDA	3.98389	0.00880	0.1398	0.1538
62	Enbridge CDA	Union SWDA	4.11969	0.00929	0.1447	0.1592
63	Enbridge CDA	Spruce	21.08017	0.05763	0.7506	0.8257
64	Enbridge CDA	Emerson 1	20.65724	0.05633	0.7354	0.8089
65	Enbridge CDA	Emerson 2	20.65724	0.05633	0.7354	0.8089

RATES AND STATISTICS

Exchange Rates

Text + – R Print

Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 07 Aug 2009

Convert to and from Canadian dollars, using the latest noon rates.

Currency:	U.S. dollar
Amount:	1.00
Convert:	(•) from $Can ( ) to $Can
Use the:	(•) Nominal rate HELP ( ) Cash rate (4%) HELP
Answer:	0.92 CONVERT
Exchange rate:	0.9228

Summary:

On 07 Aug 2009, 1.00 Canadian dollar(s) = 0.92 U.S. dollar (s), at an exchange rate of 0.9228 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

Why is the currency I'm looking for not listed here?

The Bank currently collects data for over 50 foreign currencies. These data are intended primarily for individuals with a research interest in foreign exchange markets and represent only a sampling of currencies.

More comprehensive currency converters include CanadianForex, HiFX, or OANDA.com.

Are the exchange rates shown here accepted by the Canada Revenue Agency?

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income and expenses that are denominated in foreign currencies.

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Line	Description	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak Nov- Apr
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2009 - 2010 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 62 * ln 101							
13	Niagara Supply	ln 63 * ln 106							
14	TGP Supply (Direct)	ln 64 * ln 120							
15	Dracut Winter Supply 1	ln 65 * ln 111							
16	Dracut Winter Supply 2	ln 66 * ln 116							
17	City Gate Delivered Supply	ln 67 * ln 128							
18	LNG Truck	ln 68 * ln 130							
19	Propane Truck	ln 69 * ln 132							
20	PNGTS	ln 70 * ln 137							
21	Granite Ridge	ln 71 * ln 142							
22									
23	Subtotal Pipeline Gas Costs		$ 5,841,340	$ 8,663,193	$ 10,150,336	$ 8,725,381	$ 8,571,653	$ 7,049,190	$ 49,001,094
24									
25	**Volumetric Transportation Costs**								
26	Dawn Supply	ln 62 * ln 189							
27	Niagara Supply	ln 63 * ln 200							
28	TGP Supply (Direct)	ln 64 * ln 227							
29	Dracut Winter Supply 1	ln 65 * ln 248							
30	Dracut Winter Supply 2	ln 66 * ln 248							
31	TGP Storage - Withdrawals	ln 76 * ln 164							
32									
33	**Total Volumetric Transportation Costs**		$ 375,100	$ 525,993	$ 612,588	$ 515,762	$ 470,643	$ 377,895	$ 2,877,981
34									
35	**Less - Gas Refill:**								
36	LNG Truck	ln 85 * ln 149							
37	Propane	ln 86 * ln 150							
38	TGP Storage Refill	ln 87 * ln 120							
39	Storage Refill (Trans.)	ln 87 * ln 227							
40									
41	Subtotal Refills		$ (351,899)	$ (241,250)	$ (229,476)	$ (138,786)	$ (27,731)	$ (2,491,892)	$ (3,481,033)
42									
43	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 33 + ln 41	$ 5,864,541	$ 8,947,936	$ 10,533,449	$ 9,102,357	$ 9,014,566	$ 4,935,192	$ 48,398,041
44									
45	**Storage Gas:**								
46	TGP Storage - Withdrawals	ln 76 * ln 156	$ -	$ 1,844,255	$ 3,483,984	$ 2,255,300	$ -	$ -	$ 7,583,539
47									
48	**Produced Gas:**								
49	LNG Vapor	ln 79 * ln 144							
50	Propane	ln 80 * ln 146							
51									
52	**Total Produced Gas**	ln 49 + ln 50	$ 18,241	$ 92,217	$ 319,866	$ 191,551	$ 17,804	$ 17,804	$ 657,484
53									
54									
55	**Total Commodity Gas & Trans. Costs**	ln 43 + ln 46 + ln 52	$ 5,882,782	$ 10,884,408	$ 14,337,299	$ 11,549,209	$ 9,032,370	$ 4,952,997	$ 56,639,065
56									
57									

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line									
5									Peak
6	For Month of:	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
58									
59	**Volumes (Therms)**								
60									
61	**Pipeline Gas:**	See Schedule 11A							
62	Dawn Supply		1,020,327	1,054,338	1,054,338	952,306	1,054,338	1,020,327	6,155,975
63	Niagara Supply		796,706	777,149	783,101	638,555	820,513	98,632	3,914,656
64	TGP Supply (Direct)		5,448,548	5,669,619	5,692,576	5,103,337	5,692,576	5,212,172	32,818,830
65	Dracut Winter Supply 1		-	6,530,945	6,530,945	5,899,193	-	-	18,961,083
66	Dracut Winter Supply 2		4,544,708	151,349	599,442	174,306	6,274,163	5,858,380	17,602,348
67	City Gate Delivered Supply		-	-	-	-	-	-	-
68	LNG Truck		23,808	124,990	407,281	244,879	49,316	-	850,273
69	Propane Truck		-	-	-	-	-	-	-
70	PNGTS		62,070	79,926	93,530	73,974	70,573	49,316	429,388
71	Granite Ridge		-	-	-	-	-	-	-
72									
73	Subtotal Pipeline Volumes		11,896,167	14,388,316	15,161,214	13,086,549	13,961,479	12,238,827	80,732,552
74									
75	**Storage Gas:**								
76	TGP Storage		-	2,564,423	4,911,176	3,179,170	-	-	10,654,768
77									
78	**Produced Gas:**								
79	LNG Vapor		23,808	124,990	442,992	265,285	24,658	24,658	906,391
80	Propane		-	-	-	-	-	-	-
81									
82	Subtotal Produced Gas		23,808	124,990	442,992	265,285	24,658	24,658	906,391
83									
84	**Less - Gas Refill:**								
85	LNG Truck		(23,808)	(124,990)	(407,281)	(244,879)	(49,316)	-	(850,273)
86	Propane		-	-	-	-	-	-	-
87	TGP Storage Refill		(663,213)	(292,494)	-	-	-	(4,083,010)	(5,038,717)
88									
89	Subtotal Refills		(687,020)	(417,484)	(407,281)	(244,879)	(49,316)	(4,083,010)	(5,888,989)
90									
91	**Total Sendout Volumes**		11,232,954	16,660,245	20,108,101	16,286,125	13,936,821	8,180,475	86,404,722
92									
93									
94									

00000031

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line									
5									Peak
6	For Month of:	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
95	**Gas Costs and Volumetric Transportation Rates**								Average Rate
96									
97	**Pipeline Gas:**								
98	**Dawn Supply**								
99	NYMEX Price	Sch 7, ln 10/10							
100	Basis Differential								
101	**Net Commodity Costs**								
102									
103	**Niagara Supply**								
104	NYMEX Price	Sch 7, ln 10/10							
105	Basis Differential								
106	**Net Commodity Costs**								
107									
108	**Dracut Winter Supply 1**								
109	**Commodity Costs - NYMEX Price**	Sch 7, ln 10 / 10							
110	**Basis Differential**								
111	**Net Commodity Costs**								
112									
113	**Dracut Winter Supply 2**								
114	**Commodity Costs - NYMEX Price**	Sch 7, ln 10 / 10							
115	**Basis Differential**								
116	**Net Commodity Costs**								
117									
118									
119	**TGP Supply (Direct)**								
120	NYMEX Price	Sch 7, ln 10/10	$0.4611	$0.5365	$0.5634	$0.5668	$0.5623	$0.5563	**$0.5411**
121									
122	**Dracut Winter Supply 1**								
123	**Commodity Costs - NYMEX Price**	Sch 7, ln 10/10	$0.4611	$0.5365	$0.5634	$0.5668	$0.5623	$0.5563	**$0.5411**
124									
125	**City Gate Delivered Supply**								
126	**NYMEX Price**	Sch 7, ln 10/10							
127	**Basis Differential**								
128	**Net Commodity Costs**								
129									
130	**LNG Truck**	Sch 7, ln 10/10	**$0.4611**	**$0.5365**	**$0.5634**	**$0.5668**	**$0.5623**	**$0.5563**	**$0.5411**
131									
132	**Propane Truck**	NYMEX - Propane	**$1.2750**	**$1.2860**	**$1.2970**	**$1.3050**	**$1.3130**	**$1.3220**	**$1.2997**
133									
134	**PNGTS**								
135	NYMEX Price	Sch 7, ln 10/10							
136	Additional Cost								
137	**Net Commodity Cost**								
138									
139	**Granite Ridge**								
140	NYMEX Price	Sch 7, ln 10/10							
141	Additional Cost								
142	**Net Commodity Cost**								
143									
144	**LNG Vapor (Storage)**	Sch 16, ln 122 /10	**$0.7662**	**$0.7378**	**$0.7221**	**$0.7221**	**$0.7221**	**$0.7221**	**$0.7320**
145									
146	**Propane**	Sch 16, ln 84 /10	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**
147									
148	**Storage Refill:**								
149	**LNG Truck**	ln 130	**$0.4611**	**$0.5365**	**$0.5634**	**$0.5668**	**$0.5623**	**$0.5563**	**$0.7320**
150	**Propane**	ln 132	**$1.2750**	**$1.2860**	**$1.2970**	**$1.3050**	**$1.3130**	**$1.3220**	**$1.4621**
151									
152									

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln									
5									Peak
6	For Month of:	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
153									
154									Average Rate
155	**TGP Storage**								
156	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.7915	$0.7192	$0.7094	$0.7094	$0.6831	$0.6637	$0.7127
157									
158	TGP - Max Commodity - Z 4-6	20th Rev Sheet No. 23A	$0.00834	$0.00834	$0.00834	$0.00834	$0.00834	$0.00834	$0.00834
159	TGP - Max Comm. ACA Rate - Z 4-6	20th Rev Sheet No. 23A	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017
160	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.00851	$0.00851	$0.00851	$0.00851	$0.00851	$0.00851	$0.00851
161	TGP - Fuel Charge % - Z 4-6	3rd Rev Sheet No. 29	2.17%	2.17%	2.17%	2.17%	2.17%	1.92%	2.13%
162	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.01718	$0.01561	$0.01539	$0.01539	$0.01482	$0.01274	$0.01519
163	TGP - Withdrawal Charge	17th Rev Sheet No. 27	$0.00102	$0.00102	$0.00102	$0.00102	$0.00102	$0.00102	$0.00102
164	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.02671	$0.02514	$0.02492	$0.02492	$0.02435	$0.02227	$0.02472
165									
166	**Total TGP - Comm. & Vol. Trans. Rate**	ln 156 + ln 164	**$0.81823**	**$0.74431**	**$0.73432**	**$0.73432**	**$0.70747**	**$0.68599**	**$0.73744**
167									
168									
169	**Per Unit Volumetric Transportation Rates**								
170	**Dawn Supply Volumetric Transportation Charge**								
171	**Commodity Costs**	ln 101	**$0.4951**	**$0.5705**	**$0.5974**	**$0.6008**	**$0.5963**	**$0.5903**	**$0.5751**
172									
173	TransCanada - Commodity Rate/GJ	Union Dawn to Iroquois	$0.00195	$0.00195	$0.00195	$0.00195	$0.00195	$0.00195	$0.00195
174	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
175	Conversion Rate to US$	08/07/2009	0.9228	0.9228	0.9228	0.9228	0.9228	0.9228	0.9228
176	Commodity Rate/US$	ln 173 x ln 174 x ln 175	$0.00190	$0.00190	$0.00190	$0.00190	$0.00190	$0.00190	$0.00190
177	TransCanada Fuel %	Union Dawn to Iroquois	1.09%	1.59%	1.66%	1.89%	1.37%	1.43%	1.51%
178	TransCanada Fuel * Percentage	ln 171 x ln 177	$0.00540	$0.00907	$0.00992	$0.01135	$0.00817	$0.00844	$0.00872
179	Subtotal TransCanada		**$0.00730**	**$0.01097**	**$0.01182**	**$0.01326**	**$0.01007**	**$0.01034**	**$0.01063**
180	IGTS - Z1 RTS Commodity	31st Rev Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
181	IGTS - Z1 RTS ACA Rate Commodity	22nd Rev Sheet 4A	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017
182	IGTS - Z1 RTS Deferred Asset Surcharge	22nd Rev Sheet 4A	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004
183	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00051**	**$0.00051**	**$0.00051**	**$0.00051**	**$0.00051**	**$0.00051**	**$0.00051**
184	TGP NET-NE - Comm. Segments 3 & 4	42nd Rev Sheet No. 26B	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017
185	IGTS -Fuel Use Factor - Percentage	22nd Rev Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
186	IGTS -Fuel Use Factor - Fuel * Percentage	ln 171 x ln 185	**$0.00495**	**$0.00570**	**$0.00597**	**$0.00601**	**$0.00596**	**$0.00590**	**$0.00575**
187	TGP NET-284 - Fuel Charge % Z 4-6	5th Rev Sheet 220A	1.54%	1.54%	1.54%	1.54%	1.54%	1.54%	1.54%
188	TGP NET-284 -Fuel Use Factor - Fuel * %	ln 171 x ln 187	**$0.00762**	**$0.00879**	**$0.00920**	**$0.00925**	**$0.00918**	**$0.00909**	**$0.00886**
189	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.02055**	**$0.02614**	**$0.02767**	**$0.02919**	**$0.02590**	**$0.02602**	**$0.02591**
190									
191									
192	**Niagara Supply Volumetric Transportation Charge**								
193	**Commodity Costs**	Ln 106							
194									
195	TGP FTA - FTA Z 5-6 Comm. Rate	20th Rev Sheet No. 23A							
196	TGP FTA - FTA Z 5-6 - ACA Rate	20th Rev Sheet No. 23A							
197	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
198	TGP FTA Fuel Charge % Z 5-6	3rd Rev Sheet No. 29							
199	TGP FTA Fuel * Percentage	ln 193 x ln 198							
200	**Total Volumetric Transportation Rate - Niagra Supply**								
201									
202									
203						**THIS PAGE HAS BEEN REDACTED**			

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln	For Month of:	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
204									
205									
206	**TGP Direct Volumetric Transportation Charge**								Average Rate
207	**Commodity Costs**	Ln 120	**$0.4611**	**$0.5365**	**$0.5634**	**$0.5668**	**$0.5623**	**$0.5563**	**$0.5411**
208									
209	TGP - Max Comm. Base Rate - Z 0-6	20th Rev Sheet No. 23A	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608
210	TGP - Max Commodity ACA Rate - Z 0-6	20th Rev Sheet No. 23A	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017
211	Subtotal TGP - Max Comm. Rate Z 0-6		$0.01625	$0.01625	$0.01625	$0.01625	$0.01625	$0.01625	$0.01625
212	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
213	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**
214	TGP - Max Comm. Base Rate - Z 1-6	20th Rev Sheet No. 23A	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503
215	TGP - Max Commodity ACA Rate - Z 1-6	20th Rev Sheet No. 23A	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017
216	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.01520	$0.01520	$0.01520	$0.01520	$0.01520	$0.01520	$0.01520
217	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
218	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**
219	TGP - Fuel Charge % - Z 0 -6	3rd Rev Sheet No. 29	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.50%
220	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
221	Prorated TGP Fuel Charge % - Z 0-6		2.84%	2.84%	2.84%	2.84%	2.84%	2.42%	2.77%
222	TGP - Fuel Charge % - Z 1 -6	3rd Rev Sheet No. 29	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	7.63%
223	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
224	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		5.27%	5.27%	5.27%	5.27%	5.27%	4.50%	5.14%
225	TGP - Fuel Charge % - Z 0-6	ln 207 x ln 221	**$0.01309**	**$0.01523**	**$0.01600**	**$0.01609**	**$0.01597**	**$0.01346**	**$0.01497**
226	TGP - Fuel Charge % - Z 1-6	ln 207 x ln 224	**$0.02430**	**$0.02828**	**$0.02970**	**$0.02987**	**$0.02964**	**$0.02501**	**$0.02780**
227	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.05294**	**$0.05905**	**$0.06124**	**$0.06151**	**$0.06115**	**$0.05401**	**$0.05831**
228									
229	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
230	**Commodity Costs**	Ln 123	**$0.4611**	**$0.5365**	**$0.5634**	**$0.5668**	**$0.5623**	**$0.5563**	**$0.5411**
231									
232	TGP - Max Comm. Base Rate - Z 6-6	20th Rev Sheet No. 23A	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642
233	TGP - Max Commodity ACA Rate - Z 6-6	20th Rev Sheet No. 23A	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017	$0.00017
234	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00659**	**$0.00659**	**$0.00659**	**$0.00659**	**$0.00659**	**$0.00659**	**$0.00659**
235	TGP - Fuel Charge % - Z 6-6	3rd Rev Sheet No. 29	0.89%	0.89%	0.89%	0.89%	0.89%	0.85%	0.88%
236	TGP - Fuel Charge	ln 230 x ln 235	**$0.00410**	**$0.00477**	**$0.00501**	**$0.00504**	**$0.00500**	**$0.00473**	**$0.00478**
237	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.01069**	**$0.01136**	**$0.01160**	**$0.01163**	**$0.01159**	**$0.01132**	**$0.01137**
238									
239									
240	**TGP Dracut**								
241	**Commodity Costs - NYMEX Price**	Ln 111							
242									
243	TGP - Trans Charge - Comm. - Z 6-6	20th Rev Sheet No. 23A							
244	TGP - Trans Charge - ACA Rate - Z6-6	20th Rev Sheet No. 23A							
245	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
246	TGP - Fuel Charge % - Z 6-6	3rd Rev Sheet No. 29							
247	TGP - Fuel Charge	ln 241 x ln 246							
248	**Total Volumetric Transportation Rate - TGP Dracut**								
249									
250					**THIS PAGE HAS BEEN REDACTED**				
251									

--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates ---- Applicable to Non-Eastchester/Non-Contesting Shippers 2/ ---- Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).
2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.
3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:
Commodity 0.0017

DEFERRED ASSET SURCHARGE:
Commodity
Zone 1 0.0004
Zone 2 0.0002
Inter-Zone 0.0006
MEASUREMENT VARIANCE/FUEL USE FACTOR:
Minimum 0.00%
Maximum (Non-Eastchester Shipper) 1.00%
Maximum (Eastchester Shipper) 4.50%
Maximum (Brookfield Shipper) 1.20%

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0456		$0.0686	$0.0897	$0.0995	$0.1135	$0.1248	$0.1625
L		$0.0303						
1	$0.0686		$0.0589	$0.0793	$0.0891	$0.1031	$0.1143	$0.1520
2	$0.0897		$0.0793	$0.0450	$0.0547	$0.0698	$0.0800	$0.1176
3	$0.0995		$0.0891	$0.0547	$0.0383	$0.0680	$0.0782	$0.1159
4	$0.1146		$0.1042	$0.0698	$0.0680	$0.0418	$0.0476	$0.0851
5	$0.1248		$0.1143	$0.0800	$0.0782	$0.0476	$0.0444	$0.0782
6	$0.1625		$0.1520	$0.1176	$0.1159	$0.0851	$0.0782	$0.0659

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0017

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/						
Segment U	$9.65			$0.00	$9.65	
Segment 1	$1.33			$0.00	$1.33	
Segment 2	$8.08			$0.00	$8.08	
Segment 3	$5.07			$0.00	$5.07	
Segment 4	$5.54			$0.00	$5.54	
Commodity Rate 2/, 3/						
Segments U, 1, 2, 3 & 4	$0.0017				$0.0017	6/
Extended Receipt and Delivery Rate 4/, 7/						
Segment U	$0.3173				$0.3173	5.52%
Segment 1	$0.0437				$0.0437	0.69%
Segment 2	$0.2656				$0.2656	0.59%
Segment 3	$0.1667				$0.1667	0.73%
Segment 4	$0.1821				$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 220A.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (TCSM) (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.02	$0.00	$2.02	
Space Rate	$0.0248	$0.0000	$0.0248	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	
Overrun Rate	$0.2427		$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.15	$0.00	$1.15	
Space Rate	$0.0185	$0.0000	$0.0185	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
Overrun Rate	$0.1380		$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA				
Space Rate	$0.0848	$0.0000	$0.0848	
Injection Rate	$0.0102		$0.0102	1.49%
Withdrawal Rate	$0.0102		$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA				
Space Rate	$0.0993	$0.0000	$0.0993	
Injection Rate	$0.0053		$0.0053	1.49%
Withdrawal Rate	$0.0053		$0.0053	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

NET-284 RATE SCHEDULE (continued)

Shipper	Transportation Quantity (Dth)	Segments U	1	2	3	4	Fuel and Use
Bay State (from Granite) - Pleasant St.	3,706				*	*	1.26%
Bay State (from Granite) - Agawam	6,068				*		0.96%
Boston Gas	35,000				*	*	1.31%
Boston Gas	8,600				*	*	1.31%
Dartmouth Power	14,010				*	*	1.23%
EnergyNorth Natural Gas, Inc.	4,000				*	*	1.54%
Essex County Gas Company	2,000				*	*	1.44%
Iroquois (Connecticut Natural, Yankee Gas)	37,000				*		0.68%
Lockport Energy Associates	28,000	*	*				6.21%
Northern Utilities (from Granite) Pleasant St.	844				*	*	1.26%
Northern Utilities (from Granite) Agawam	1,382				*		0.96%
Project Orange	20,000		*	*			1.28%
Valley Gas Company	1,000				*	*	1.25%
Yankee Gas (Wright)	9,000				*		1.07%
Total	170,610						

TransCanada
In business to deliver

Transportation Tolls
2009 Final Tolls Effective May 1st

1 **Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls**

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
2	Centra Gas Manitoba - MDA	2.34500	0.00462
3	Union Gas - WDA	16.66667	0.04509
4	Union Gas - NDA	6.45333	0.01622
5	Union Gas - EDA	4.22833	0.00964
6	Kingston PUC	4.06250	0.00908
7	Gaz Metropolitain - EDA	7.51000	0.01911
8	Enbridge - CDA	0.93583	0.00015
9	Enbridge - EDA	2.58833	0.00499
10	Cornwall	5.76167	0.01393
11	Philipsburg	7.58917	0.01914

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
12	ECR Surcharge	0.029

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
13	Emerson - 1 (Viking)	0.06426	0.00000	0.00211
14	Emerson - 2 (Great Lakes)	0.08446	0.00000	0.00278
15	Dawn	0.06286	0.00000	0.00207
16	Niagara Falls	0.10558	0.00000	0.00347
17	Iroquois	0.56297	0.00000	0.01851
18	Chippawa	0.61730	0.00000	0.02029
19	East Hereford	1.41498	0.02139	0.06791

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

FT, STFT and Interruptible Transportation Tolls
2009 Final Tolls Effective May 1st
* These tolls will become effective on November 1, 2009

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	STFT Minimum Tolls (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% LF FT Tolls) ($/GJ)
1	Emerson 2	Napierville	25.40156	0.06991	0.9050	0.9955
2	Emerson 2	Philipsburg	25.58592	0.07044	0.9116	1.0028
3	Emerson 2	East Hereford	27.52555	0.07597	0.9809	1.0790
4	Union Dawn	Empress	28.28112	0.00000	0.9298	1.0228
5	Union Dawn	Transgas SSDA	24.33086	0.00000	0.7999	0.8799
6	* *Union Dawn*	*Transgas SSDA*	24.82353	0.00000	0.8161	0.8977
7	Union Dawn	Centram SSDA	21.86751	0.00000	0.7189	0.7908
8	Union Dawn	Centram MDA	19.03032	0.05218	0.6779	0.7457
9	Union Dawn	Centrat MDA	19.03776	0.05177	0.6777	0.7455
10	Union Dawn	Union WDA	18.74224	0.05102	0.6672	0.7339
11	Union Dawn	Nipigon WDA	16.73298	0.04520	0.5953	0.6548
12	Union Dawn	Union NDA	8.83255	0.02300	0.3134	0.3447
13	Union Dawn	Calstock NDA	13.26448	0.03532	0.4714	0.5185
14	Union Dawn	Tunis NDA	10.53372	0.02753	0.3738	0.4112
15	Union Dawn	GMIT NDA	8.49698	0.02156	0.3010	0.3311
16	Union Dawn	Union SSMDA	7.25587	0.01819	0.2567	0.2824
17	Union Dawn	Union NCDA	5.18095	0.01233	0.1826	0.2009
18	Union Dawn	Union CDA	3.30151	0.00680	0.1153	0.1268
19	Union Dawn	Enbridge CDA	3.98389	0.00880	0.1398	0.1538
20	Union Dawn	Union EDA	6.95563	0.01711	0.2458	0.2704
21	Union Dawn	Enbridge EDA	8.17713	0.02087	0.2897	0.3187
22	Union Dawn	GMIT EDA	9.88931	0.02589	0.3510	0.3861
23	Union Dawn	KPUC EDA	6.44157	0.01587	0.2277	0.2505
24	Union Dawn	North Bay Junction	7.02348	0.01753	0.2484	0.2732
25	Union Dawn	Enbridge SWDA	0.87529	0.00000	0.0288	0.0317
26	Union Dawn	Union SWDA	1.09017	0.00000	0.0358	0.0394
27	Union Dawn	Spruce	19.03776	0.05177	0.6777	0.7455
28	Union Dawn	Emerson 1	17.54958	0.00000	0.5770	0.6347
29	Union Dawn	Emerson 2	17.54958	0.00000	0.5770	0.6347
30	Union Dawn	St. Clair	1.12519	0.00000	0.0370	0.0407
31	Union Dawn	Dawn Export	0.87529	0.00000	0.0288	0.0317
32	Union Dawn	Kirkwall	2.85383	0.00564	0.0994	0.1093
33	Union Dawn	Niagara Falls	4.02646	0.00898	0.1414	0.1555
34	Union Dawn	Chippawa	4.05153	0.00905	0.1423	0.1565
35	Union Dawn	Iroquois	7.72830	0.01953	0.2736	0.3010
36	Union Dawn	Cornwall	8.14221	0.02071	0.2884	0.3172
37	Union Dawn	Napierville	9.78381	0.02539	0.3471	0.3818
38	Union Dawn	Philipsburg	9.96827	0.02592	0.3536	0.3890
39	Union Dawn	East Hereford	11.90791	0.03145	0.4230	0.4653
40	Enbridge CDA	Empress	31.70810	0.08792	1.1304	1.2434
41	Enbridge CDA	Transgas SSDA	27.83218	0.07467	0.9897	1.0887
42	* *Enbridge CDA*	*Transgas SSDA*	28.32485	0.07609	1.0073	1.1080
43	Enbridge CDA	Centram SSDA	24.85939	0.06833	0.8856	0.9742
44	Enbridge CDA	Centram MDA	22.42153	0.06187	0.7990	0.8789
45	Enbridge CDA	Centrat MDA	21.14728	0.05781	0.7531	0.8284
46	Enbridge CDA	Union WDA	16.43683	0.04444	0.5848	0.6433
47	Enbridge CDA	Nipigon WDA	14.65020	0.03987	0.5216	0.5738
48	Enbridge CDA	Union NDA	6.39952	0.01609	0.2265	0.2492
49	Enbridge CDA	Calstock NDA	11.34823	0.03072	0.4038	0.4442
50	Enbridge CDA	Tunis NDA	8.74845	0.02352	0.3111	0.3422
51	Enbridge CDA	GMIT NDA	6.37278	0.01463	0.2241	0.2465
52	Enbridge CDA	Union SSMDA	10.36446	0.02699	0.3677	0.4045
53	Enbridge CDA	Union NCDA	2.74487	0.00541	0.0956	0.1052
54	Enbridge CDA	Union CDA	1.87122	0.00258	0.0641	0.0705
55	Enbridge CDA	Enbridge CDA	0.87529	0.00000	0.0288	0.0317
56	Enbridge CDA	Union EDA	3.93145	0.00878	0.1381	0.1519
57	Enbridge CDA	Enbridge EDA	5.65768	0.01371	0.1997	0.2197
58	Enbridge CDA	GMIT EDA	7.19001	0.01822	0.2546	0.2801
59	Enbridge CDA	KPUC EDA	3.74248	0.00819	0.1312	0.1443
60	Enbridge CDA	North Bay Junction	4.58363	0.01060	0.1613	0.1774
61	Enbridge CDA	Enbridge SWDA	3.98389	0.00880	0.1398	0.1538
62	Enbridge CDA	Union SWDA	4.11969	0.00929	0.1447	0.1592
63	Enbridge CDA	Spruce	21.08017	0.05763	0.7506	0.8257
64	Enbridge CDA	Emerson 1	20.65724	0.05633	0.7354	0.8089
65	Enbridge CDA	Emerson 2	20.65724	0.05633	0.7354	0.8089

TransCanada Fuel Ratios

November-2008

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3662	1.09	0.61

December-2008

Pressure Point	Pressure (%)
Chippawa	0.69
Emerson 1	0.18
Emerson 2	0.18
Iroquois	0.48
Niagara Falls	0.00

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Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3662	1.59	1.11

January-2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

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For fuel ratios or bid tolls questions please contact Paulo Deoliveira (1.403.

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3010	1.66	0.97

February-2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

This page is maintained by Graham Gent (1.403.920.6846).

For fuel ratios or bid tolls questions please contact Paulo Deoliveira (1.4

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3010	1.89	1.20

March-2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3010	1.37	0.68

April-2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3010	1.43	0.74

Line									
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2009 - 2010 Winter Cost of Gas Filing**								
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**								
5									Peak
6	For Month of:	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Strip Average
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**								
9		Opening Prices (15 day average)							
10		NYMEX	4.6111	5.3649	5.6343	5.6675	5.6231	5.5630	$ 5.4107
11		11/26/2009							
12		12/23/2009							
13		01/25/2010							
14		02/25/2010							
15		03/25/2010							
16		03/25/2010							
17									
18									
19									
20	**II. Development of Hedging Costs and Savings**								
21									
22	**TGP (Direct) Volumes**								Total
23	Hedged Volumes (Dth)	ln 103	648,000	1,018,000	969,000	1,030,000	900,000	633,000	5,198,000
24	Market Priced Volumes (Dth)		533,029	400,340	497,040	246,770	484,159	585,951	2,747,289
25	Total Volumes (Dth)	Sch 6, lns 62 - 67 / 10	1,181,029	1,418,340	1,466,040	1,276,770	1,384,159	1,218,951	7,945,289
26	Percentage of Volumes Hedged	ln 23 / ln 25	59%	61%	68%	75%	78%	68%	65.4%
27									Weighted Average
28	Hedge Price	ln 233	$ 7.0578	$ 7.6329	$ 8.0802	$ 7.9731	$ 7.7935	$ 7.1979	$ 7.6868
29	NYMEX Price	ln 10	$ 4.6111	$ 5.3649	$ 5.6343	$ 5.6675	$ 5.6231	$ 5.5630	$ 5.4500
30									
31	Hedged Volumes at Hedged Price	ln 23 * ln 28	$ 4,573,481	$ 7,770,251	$ 7,829,749	$ 8,212,292	$ 7,014,155	$ 4,556,255	$ 39,956,183
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29	2,987,971	5,461,502	5,459,669	5,837,559	5,060,760	3,521,379	28,328,841
33									
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32	$ 1,585,510	$ 2,308,749	$ 2,370,080	$ 2,374,733	$ 1,953,395	$ 1,034,876	$ 11,627,343
35									
36									
37									
38									
39									
40									

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line												Peak
5												
6	For Month of:				Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Strip Average
7	(a)				(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41												
42	Hedged Volumes (Dth)											
43	Hedge # 1	Trade Date	02-May-08	Swaps								
44	Hedge # 2	Trade Date	02-May-08	Swaps								
45	Hedge # 3	Trade Date	16-May-08	Swaps								
46	Hedge # 4	Trade Date	16-May-08	Swaps								
47	Hedge # 5	Trade Date	06-Jun-08	Swaps								
48	Hedge # 6	Trade Date	06-Jun-08	Swaps								
49	Hedge # 7	Trade Date	20-Jun-08	Swaps								
50	Hedge # 8	Trade Date	20-Jun-08	Swaps								
51	Hedge # 9	Trade Date	11-Jul-08	Swaps								
52	Hedge # 10	Trade Date	11-Jul-08	Swaps								
53	Hedge # 11	Trade Date	25-Jul-08	Swaps								
54	Hedge # 12	Trade Date	25-Jul-08	Swaps								
55	Hedge # 13	Trade Date	08-Aug-08	Swaps								
56	Hedge # 14	Trade Date	08-Aug-08	Swaps								
57	Hedge # 15	Trade Date	25-Aug-08	Swaps								
58	Hedge # 16	Trade Date	25-Aug-08	Swaps								
59	Hedge # 17	Trade Date	05-Sep-08	Swaps								
60	Hedge # 18	Trade Date	05-Sep-08	Swaps								
61	Hedge # 19	Trade Date	19-Sep-08	Swaps								
62	Hedge # 20	Trade Date	19-Sep-08	Swaps								
63	Hedge # 21	Trade Date	20-Oct-08	Swaps								
64	Hedge # 22	Trade Date	20-Oct-08	Swaps								
65	Hedge # 23	Trade Date	07-Nov-08	Swaps								
66	Hedge # 24	Trade Date	07-Nov-08	Swaps								
67	Hedge # 25	Trade Date	21-Nov-08	Swaps								
68	Hedge # 26	Trade Date	21-Nov-08	Swaps								
69	Hedge # 27	Trade Date	30-Dec-08	Swaps								
70	Hedge # 28	Trade Date	30-Dec-08	Swaps								
71	Hedge # 29	Trade Date	02-Jan-09	Swaps								
72	Hedge # 30	Trade Date	02-Jan-09	Swaps								
73	Hedge # 31	Trade Date	09-Jan-09	Swaps								
74	Hedge # 32	Trade Date	09-Jan-09	Swaps								
75	Hedge # 33	Trade Date	29-Jan-09	Swaps								
76	Hedge # 34	Trade Date	29-Jan-09	Swaps								
77	Hedge # 35	Trade Date	09-Feb-09	Swaps								
78	Hedge # 36	Trade Date	09-Feb-09	Swaps								
79	Hedge # 37	Trade Date	23-Mar-09	Swaps								
80	Hedge # 38	Trade Date	23-Mar-09	Swaps								
81	Hedge # 39	Trade Date	26-Mar-09	Swaps								
82	Hedge # 40	Trade Date	26-Mar-09	Swaps								
83	Hedge # 41	Trade Date	26-Mar-09	Swaps								
84	Hedge # 42	Trade Date	09-Apr-09	Swaps								
85	Hedge # 43	Trade Date	09-Apr-09	Swaps								
86	Hedge # 44	Trade Date	30-Apr-09	Swaps								
87	Hedge # 45	Trade Date	30-Apr-09	Swaps								
88	Hedge # 46	Trade Date	15-May-09	Swaps								
89	Hedge # 47	Trade Date	15-May-09	Swaps								
90	Hedge # 48	Trade Date	29-May-09	Swaps								
91	Hedge # 49	Trade Date	29-May-09	Swaps								
92	Hedge # 50	Trade Date	12-Jun-09	Swaps								
93	Hedge # 51	Trade Date	12-Jun-09	Swaps								
94	Hedge # 52	Trade Date	25-Jun-09	Swaps								
95	Hedge # 53	Trade Date	25-Jun-09	Swaps								
96	Hedge # 54	Trade Date	10-Jul-09	Swaps								
97	Hedge # 55	Trade Date	10-Jul-09	Swaps								
98	Hedge # 56	Trade Date	27-Jul-09	Swaps								
99	Hedge # 57	Trade Date	27-Jul-09	Swaps								
100												
101	Subtotal Hedge Volumes					620,000	970,000	920,000	990,000	870,000	600,000	4,970,000
102	Remaining					28,000	48,000	49,000	40,000	30,000	33,000	228,000
103	Total Volumes					648,000	1,018,000	969,000	1,030,000	900,000	633,000	5,198,000
104												
105												

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line													
5													Peak
6	For Month of:				Reference		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Strip Average
7		(a)			(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
106	Strike Price												Weighted Avera
107	Hedge # 1	Trade Date	02-May-08	Swaps		4.4000							
108	Hedge # 2	Trade Date	02-May-08	Swaps		12.5020							
109	Hedge # 3	Trade Date	16-May-08	Swaps									
110	Hedge # 4	Trade Date	16-May-08	Swaps									
111	Hedge # 5	Trade Date	06-Jun-08	Swaps									
112	Hedge # 6	Trade Date	06-Jun-08	Swaps									
113	Hedge # 7	Trade Date	20-Jun-08	Swaps									
114	Hedge # 8	Trade Date	20-Jun-08	Swaps									
115	Hedge # 9	Trade Date	11-Jul-08	Swaps									
116	Hedge # 10	Trade Date	11-Jul-08	Swaps									
117	Hedge # 11	Trade Date	25-Jul-08	Swaps									
118	Hedge # 12	Trade Date	25-Jul-08	Swaps									
119	Hedge # 13	Trade Date	08-Aug-08	Swaps									
120	Hedge # 14	Trade Date	08-Aug-08	Swaps									
121	Hedge # 15	Trade Date	25-Aug-08	Swaps									
122	Hedge # 16	Trade Date	25-Aug-08	Swaps									
123	Hedge # 17	Trade Date	05-Sep-08	Swaps									
124	Hedge # 18	Trade Date	05-Sep-08	Swaps									
125	Hedge # 19	Trade Date	19-Sep-08	Swaps									
126	Hedge # 20	Trade Date	19-Sep-08	Swaps									
127	Hedge # 21	Trade Date	20-Oct-08	Swaps									
128	Hedge # 22	Trade Date	20-Oct-08	Swaps									
129	Hedge # 23	Trade Date	07-Nov-08	Swaps									
130	Hedge # 24	Trade Date	07-Nov-08	Swaps									
131	Hedge # 25	Trade Date	21-Nov-08	Swaps									
132	Hedge # 26	Trade Date	21-Nov-08	Swaps									
133	Hedge # 27	Trade Date	30-Dec-08	Swaps									
134	Hedge # 28	Trade Date	30-Dec-08	Swaps									
135	Hedge # 29	Trade Date	02-Jan-09	Swaps									
136	Hedge # 30	Trade Date	02-Jan-09	Swaps									
137	Hedge # 31	Trade Date	09-Jan-09	Swaps									
138	Hedge # 32	Trade Date	09-Jan-09	Swaps									
139	Hedge # 33	Trade Date	29-Jan-09	Swaps									
140	Hedge # 34	Trade Date	29-Jan-09	Swaps									
141	Hedge # 35	Trade Date	09-Feb-09	Swaps									
142	Hedge # 36	Trade Date	09-Feb-09	Swaps									
143	Hedge # 37	Trade Date	23-Mar-09	Swaps									
144	Hedge # 38	Trade Date	23-Mar-09	Swaps									
145	Hedge # 39	Trade Date	26-Mar-09	Swaps									
146	Hedge # 40	Trade Date	26-Mar-09	Swaps									
147	Hedge # 41	Trade Date	26-Mar-09	Swaps									
148	Hedge # 42	Trade Date	09-Apr-09	Swaps									
149	Hedge # 43	Trade Date	09-Apr-09	Swaps									
150	Hedge # 44	Trade Date	30-Apr-09	Swaps									
151	Hedge # 45	Trade Date	30-Apr-09	Swaps									
152	Hedge # 46	Trade Date	15-May-09	Swaps									
153	Hedge # 47	Trade Date	15-May-09	Swaps									
154	Hedge # 48	Trade Date	29-May-09	Swaps									
155	Hedge # 49	Trade Date	29-May-09	Swaps									
156	Hedge # 50	Trade Date	12-Jun-09	Swaps									
157	Hedge # 51	Trade Date	12-Jun-09	Swaps									
158	Hedge # 52	Trade Date	25-Jun-09	Swaps									
159	Hedge # 53	Trade Date	25-Jun-09	Swaps									
160	Hedge # 54	Trade Date	10-Jul-09	Swaps									
161	Hedge # 55	Trade Date	10-Jul-09	Swaps									
162	Hedge # 56	Trade Date	27-Jul-09	Swaps									
163	Hedge # 57	Trade Date	27-Jul-09	Swaps									
164													
165	Subtotal Weigthed Average Hedge Prices						$7.1683	$7.7451	$8.2105	$8.0663	$7.8683	$7.2878	7.7896
166	NYMEX						$4.6111	$5.3649	$5.6343	$5.6675	$5.6231	$5.5630	5.4460
167													
168													

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line					Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak Strip Average
5												
6	For Month of:											
7		(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
169	Hedge Dollars											
170	Hedge # 1	Trade Date	02-May-08	Swaps								
171	Hedge # 2	Trade Date	02-May-08	Swaps								
172	Hedge # 3	Trade Date	16-May-08	Swaps								
173	Hedge # 4	Trade Date	16-May-08	Swaps								
174	Hedge # 5	Trade Date	06-Jun-08	Swaps								
175	Hedge # 6	Trade Date	06-Jun-08	Swaps								
176	Hedge # 7	Trade Date	20-Jun-08	Swaps								
177	Hedge # 8	Trade Date	20-Jun-08	Swaps								
178	Hedge # 9	Trade Date	11-Jul-08	Swaps								
179	Hedge # 10	Trade Date	11-Jul-08	Swaps								
180	Hedge # 11	Trade Date	25-Jul-08	Swaps								
181	Hedge # 12	Trade Date	25-Jul-08	Swaps								
182	Hedge # 13	Trade Date	08-Aug-08	Swaps								
183	Hedge # 14	Trade Date	08-Aug-08	Swaps								
184	Hedge # 15	Trade Date	25-Aug-08	Swaps								
185	Hedge # 16	Trade Date	25-Aug-08	Swaps								
186	Hedge # 17	Trade Date	05-Sep-08	Swaps								
187	Hedge # 18	Trade Date	05-Sep-08	Swaps								
188	Hedge # 19	Trade Date	19-Sep-08	Swaps								
189	Hedge # 20	Trade Date	19-Sep-08	Swaps								
190	Hedge # 21	Trade Date	20-Oct-08	Swaps								
191	Hedge # 22	Trade Date	20-Oct-08	Swaps								
192	Hedge # 23	Trade Date	07-Nov-08	Swaps								
193	Hedge # 24	Trade Date	07-Nov-08	Swaps								
194	Hedge # 25	Trade Date	21-Nov-08	Swaps								
195	Hedge # 26	Trade Date	21-Nov-08	Swaps								
196	Hedge # 27	Trade Date	30-Dec-08	Swaps								
197	Hedge # 28	Trade Date	30-Dec-08	Swaps								
198	Hedge # 29	Trade Date	02-Jan-09	Swaps								
199	Hedge # 30	Trade Date	02-Jan-09	Swaps								
200	Hedge # 31	Trade Date	09-Jan-09	Swaps								
201	Hedge # 32	Trade Date	09-Jan-09	Swaps								
202	Hedge # 33	Trade Date	29-Jan-09	Swaps								
203	Hedge # 34	Trade Date	29-Jan-09	Swaps								
204	Hedge # 35	Trade Date	09-Feb-09	Swaps								
205	Hedge # 36	Trade Date	09-Feb-09	Swaps								
206	Hedge # 37	Trade Date	23-Mar-09	Swaps								
207	Hedge # 38	Trade Date	23-Mar-09	Swaps								
208	Hedge # 39	Trade Date	26-Mar-09	Swaps								
209	Hedge # 40	Trade Date	26-Mar-09	Swaps								
210	Hedge # 41	Trade Date	26-Mar-09	Swaps								
211	Hedge # 42	Trade Date	09-Apr-09	Swaps								
212	Hedge # 43	Trade Date	09-Apr-09	Swaps								
213	Hedge # 44	Trade Date	30-Apr-09	Swaps								
214	Hedge # 45	Trade Date	30-Apr-09	Swaps								
215	Hedge # 46	Trade Date	15-May-09	Swaps								
216	Hedge # 47	Trade Date	15-May-09	Swaps								
217	Hedge # 48	Trade Date	29-May-09	Swaps								
218	Hedge # 49	Trade Date	29-May-09	Swaps								
219	Hedge # 50	Trade Date	12-Jun-09	Swaps								
220	Hedge # 51	Trade Date	12-Jun-09	Swaps								
221	Hedge # 52	Trade Date	25-Jun-09	Swaps								
222	Hedge # 53	Trade Date	25-Jun-09	Swaps								
223	Hedge # 54	Trade Date	10-Jul-09	Swaps								
224	Hedge # 55	Trade Date	10-Jul-09	Swaps								
225	Hedge # 56	Trade Date	27-Jul-09	Swaps								
226	Hedge # 57	Trade Date	27-Jul-09	Swaps								
227												
228	Subtotal Hedge Dollars					$4,444,371	$7,512,734	$7,553,667	$7,985,591	$6,845,463	$4,372,676	$38,714,502
229	Remaining					129,110	257,517	276,082	226,701	168,692	183,579	1,241,681
230												
231		Target Hedged Dollars				$4,573,481	$7,770,251	$7,829,749	$8,212,292	$7,014,155	$4,556,255	$39,956,183
232												
233		Weighted Average Hedged Cost per Unit				$7.0578	$7.6329	$8.0802	$7.9731	$7.7935	$7.1979	$7.6868

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 08 - Apr 09 vs Nov 09 - Apr 10 - Residential Heating Rate R-3

November 1, 2009 - April 30, 2010 | **May 1, 2009 - October 31, 2009**

Residential Heating (R3)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
	08/01/2009	07/01/2009															
Winter:																	
Cust. Chg	$14.03		$14.03	$14.03	$14.03	$14.03	$14.03	$14.03	$84.18								
Headblock	$0.2467		$24.67	$24.67	$24.67	$24.67	$24.67	$24.67	$148.02								
Tailblock	$0.1859		$1.67	$9.30	$16.17	$16.36	$12.27	$5.95	$61.72								
HB Threshold	100																
Summer:																	
Cust. Chg	$14.03	$13.95								$11.46	$11.46	$13.95	$14.03	$14.03	$14.03	$78.96	$163.14
Headblock	$0.2467	$0.2453								$6.71	$6.71	$4.91	$4.93	$4.93	$4.93	$33.13	$181.15
Tailblock	$0.1859	$0.1849								$13.65	$6.83	$1.85	$1.86	$4.09	$9.48	$37.75	$99.47
HB Threshold	20	20															
Total Base Rate Amount			$40.37	$48.00	$54.87	$55.06	$50.97	$44.65	$293.92	$31.82	$25.00	$20.71	$20.82	$23.05	$28.44	$149.85	$443.76
CGA Rate - (Seasonal)			$0.9663	$0.9663	$0.9663	$0.9663	$0.9663	$0.9663	$0.9663	$0.6722	$0.6324	$0.6200	$0.6077	$0.6077	$0.6077	$0.6314	$0.8811
CGA amount			$105.33	$144.95	$180.70	$181.66	$160.41	$127.55	$900.59	$60.50	$34.78	$18.60	$18.23	$25.52	$43.15	$200.78	$1,101.37
LDAC			$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	0.0404	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0367
LDAC amount			$4.40	$6.06	$7.55	$7.59	$6.71	$5.33	$37.65	$2.34	$1.43	$0.78	$0.78	$1.09	$1.85	$8.27	$45.92
Total Bill			**$150.10**	**$199.00**	**$243.13**	**$244.32**	**$218.08**	**$177.53**	**$1,232.16**	**$94.66**	**$61.21**	**$40.09**	**$39.83**	**$49.67**	**$73.44**	**$358.89**	**$1,591.06**

Residential Heating (R3)

			Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter:	08/24/2008																
Cust. Chg	$11.46		$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$68.76								
Headblock	$0.3356		33.56	33.56	33.56	33.56	33.56	33.56	$201.36								
Tailblock	$0.1950		$1.76	$9.75	$16.97	$17.16	$12.87	$6.24	$64.74								
HB Threshold	100																
Summer:																	
Cust. Chg	$11.46	$9.88								$9.88	$9.88	$9.88	$10.25	$11.46	$11.46	$62.81	$131.57
Headblock	$0.3356	$0.2945								$5.89	$5.89	$5.89	$6.08	$6.71	$6.71	$37.17	$238.53
Tailblock	$0.1950	$0.1711								$11.98	$5.99	$1.71	$1.77	$4.29	$9.95	$35.68	$100.42
HB Threshold	20	20															
Total Base Rate Amount			$46.78	$54.77	$61.99	$62.18	$57.89	$51.26	$334.86	$27.75	$21.76	$17.48	$18.10	$22.46	$28.12	$135.66	$470.52
CGA Rate - (Seasonal)			$1.1837	$1.1380	$1.1201	$1.0988	$1.0482	$0.9470	$1.0888	$1.1870	$1.3902	$1.4244	$1.4628	$1.1702	$1.1702	$1.2646	$1.1335
CGA amount			$129.02	$170.70	$209.46	$206.57	$174.00	$125.00	$1,014.76	$106.83	$76.46	$42.73	$43.88	$49.15	$83.08	$402.14	$1,416.90
LDAC			$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	0.0260	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0243
LDAC amount			$2.83	$3.90	$4.86	$4.89	$4.32	$3.43	$24.23	$1.73	$1.06	$0.58	$0.58	$0.81	$1.36	$6.11	$30.34
Total Bill			**$178.63**	**$229.37**	**$276.31**	**$273.64**	**$236.21**	**$179.70**	**$1,373.85**	**$136.31**	**$99.28**	**$60.79**	**$62.56**	**$72.42**	**$112.56**	**$543.91**	**$1,917.76**

DIFFERENCE:

Total Bill	**($28.53)**	**($30.37)**	**($33.18)**	**($29.32)**	**($18.13)**	**($2.16)**	**($141.69)**	**($41.65)**	**($38.07)**	**($20.70)**	**($22.72)**	**($22.75)**	**($39.13)**	**($185.01)**	**($326.71)**
% Change	**-15.97%**	**-13.24%**	**-12.01%**	**-10.72%**	**-7.67%**	**-1.20%**	**-10.31%**	**-30.55%**	**-38.34%**	**-34.06%**	**-36.33%**	**-31.41%**	**-34.76%**	**-34.02%**	**-17.04%**
Base Rate	($6.40)	($6.78)	($7.11)	($7.12)	($6.92)	($6.61)	($40.94)	$4.08	$3.24	$3.22	$2.72	$0.59	$0.33	$14.18	($26.76)
% Change	-13.69%	-12.37%	-11.47%	-11.45%	-11.95%	-12.90%	-12.23%	14.69%	14.88%	18.44%	15.05%	2.63%	1.17%	10.45%	-5.69%
CGA & LDAC	($22.13)	($23.60)	($26.07)	($22.20)	($11.21)	$4.45	($100.75)	($45.72)	($41.31)	($23.93)	($25.45)	($23.34)	($39.45)	($199.20)	($299.95)
% Change	-17.15%	-13.82%	-12.45%	-10.75%	-6.44%	3.56%	-9.93%	-42.80%	-54.02%	-56.00%	-57.99%	-47.49%	-47.49%	-49.53%	-21.17%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 08 - Apr 09 vs Nov 09 - Apr 10 - Commercial Rate G-41

November 1, 2009 - April 30, 2010
Commercial Rate (G-41)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr
Typical Usage (Therms)			193	269	298	262	234	171	1,427
Winter:	08/01/2009	07/01/2009							
Cust. Chg	$35.08		$35.08	$35.08	$35.08	$35.08	$35.08	$35.08	$210.48
Headblock	$0.2974		$29.74	$29.74	$29.74	$29.74	$29.74	$29.74	$178.44
Tailblock	$0.1934		$17.99	$32.68	$38.29	$31.33	$25.92	$13.73	$159.94
HB Threshold	100								
Summer:									
Cust. Chg	$35.08	$34.88							
Headblock	$0.2974	$0.2956							
Tailblock	$0.1934	$0.1923							
HB Threshold	20	20							
Total Base Rate Amount			$82.81	$97.50	$103.11	$96.15	$90.74	$78.55	$548.86
CGA Rate - (Seasonal)			$0.9665	$0.9665	$0.9665	$0.9665	$0.9665	$0.9665	$0.9665
CGA amount			$186.53	$259.99	$288.02	$253.22	$226.16	$165.27	$1,379.20
LDAC			$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194
LDAC amount			$3.74	$5.22	$5.78	$5.08	$4.54	$3.32	$27.68
Total Bill			**$273.08**	**$362.71**	**$396.91**	**$354.46**	**$321.44**	**$247.14**	**$1,955.74**

May 1, 2009 - October 31, 2009

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	117	81	72	72	89	142	573	2,000
Cust. Chg	$28.58	$28.58	$34.88	$35.08	$35.08	$35.08	$197.28	$407.76
Headblock	$7.46	$7.46	$5.91	$5.95	$5.95	$5.95	$38.68	$217.12
Tailblock	$23.54	$14.80	$10.00	$10.06	$13.34	$23.59	$95.34	$255.28
Total Base Rate Amount	$59.59	$50.85	$50.79	$51.08	$54.37	$64.62	$331.31	$880.17
CGA Rate - (Seasonal)	$0.6727	$0.6329	$0.6205	$0.6082	$0.6082	$0.6082	$0.6264	$0.8691
CGA amount	$78.71	$51.26	$44.68	$43.79	$54.13	$86.36	$358.93	$1,738.13
LDAC	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0218
LDAC amount	$3.25	$2.25	$2.00	$2.00	$2.47	$3.95	$15.93	$43.61
Total Bill	**$141.54**	**$104.37**	**$97.47**	**$96.88**	**$110.98**	**$154.93**	**$706.17**	**$2,661.91**

November 1, 2009 - April 30, 2010
Commercial Rate (G-41)

			Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr
Typical Usage (Therms)			193	269	298	262	234	171	1,427
Winter:									
Cust. Chg	$28.58		$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$171.48
Headblock	$0.3732		37.32	37.32	37.32	37.32	37.32	37.32	$223.92
Tailblock	$0.2427		$22.57	$41.02	$48.05	$39.32	$32.52	$17.23	$200.71
HB Threshold	100								
Summer:									
Cust. Chg	$28.58	$24.64							
Headblock	$0.3732	$0.3275							
Tailblock	$0.2427	$0.2130							
HB Threshold	20	20							
Total Base Rate Amount			$88.47	$106.92	$113.95	$105.22	$98.42	$83.13	$596.11
CGA Rate - (Seasonal)			$1.1839	$1.1382	$1.1203	$1.0990	$1.0484	$0.9471	$1.0958
CGA amount			$228.49	$306.18	$333.85	$287.94	$245.33	$161.95	$1,563.74
LDAC			$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	0.0278
LDAC amount			$5.37	$7.48	$8.28	$7.28	$6.51	$4.75	$39.67
Total Bill			**$322.33**	**$420.57**	**$456.09**	**$400.44**	**$350.25**	**$249.84**	**$2,199.52**

	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	117	81	72	72	89	142	573	2,000
Cust. Chg	$24.64	$24.64	$24.64	$25.56	$28.58	$28.58	$156.64	$328.12
Headblock	$6.55	$6.55	$6.55	$6.76	$7.46	$7.46	$41.34	$265.26
Tailblock	$20.66	$12.99	$11.08	$11.44	$16.75	$29.61	$102.53	$303.24
Total Base Rate Amount	$51.85	$44.18	$42.27	$43.76	$52.79	$65.65	$300.50	$896.62
CGA Rate - (Seasonal)	$1.1874	$1.3906	$1.4249	$1.4633	$1.1706	$1.1706	$1.2739	$1.1468
CGA amount	$138.93	$112.64	$102.59	$105.36	$104.18	$166.23	$729.92	$2,293.66
LDAC	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0227
LDAC amount	$1.18	$0.82	$0.73	$0.73	$0.90	$1.43	$5.79	$45.46
Total Bill	**$191.96**	**$157.64**	**$145.59**	**$149.84**	**$157.87**	**$233.31**	**$1,036.21**	**$3,235.73**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
Total Bill	**($49.24)**	**($57.86)**	**($59.18)**	**($45.98)**	**($28.82)**	**($2.70)**	**($243.78)**
% Change	**-15.28%**	**-13.76%**	**-12.97%**	**-11.48%**	**-8.23%**	**-1.08%**	**-11.08%**
Base Rate	($5.66)	($9.41)	($10.84)	($9.07)	($7.69)	($4.58)	($47.25)
% Change	-6.40%	-8.80%	-9.51%	-8.62%	-7.81%	-5.51%	-7.93%
CGA & LDAC	($43.58)	($48.45)	($48.34)	($36.92)	($21.13)	$1.88	($196.53)
% Change	-19.07%	-15.82%	-14.48%	-12.82%	-8.61%	1.16%	-12.57%

	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($50.41)**	**($53.27)**	**($48.12)**	**($52.97)**	**($46.90)**	**($78.38)**	**($330.05)**	**($573.83)**
% Change	**-26.26%**	**-33.79%**	**-33.05%**	**-35.35%**	**-29.70%**	**-33.59%**	**-31.85%**	**-17.73%**
Base Rate	$7.73	$6.67	$8.53	$7.32	$1.58	($1.03)	$30.80	($16.45)
% Change	14.92%	15.09%	20.17%	16.74%	3.00%	-1.57%	10.25%	-1.83%
CGA & LDAC	($58.15)	($59.94)	($56.64)	($60.29)	($48.48)	($77.35)	($360.85)	($557.38)
% Change	-41.86%	-53.21%	-55.21%	-57.23%	-46.53%	-46.53%	-49.44%	-24.30%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 08 - Apr 09 vs Nov 09 - Apr 10 - Commercial Rate G-42

November 1, 2009 - April 30, 2010 / **May 1, 2009 - October 31, 2009**
C&I High Winter Use Medium G-42

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
	08/01/2009	07/01/2009															
Winter:																	
Cust. Chg	$100.24		$100.24	$100.24	$100.24	$100.24	$100.24	$100.24	$601.44								
Headblock	$0.2642		$264.20	$264.20	$264.20	$264.20	$264.20	$264.20	$1,585.20								
Tailblock	$0.1745		$96.50	$275.36	$395.24	$541.47	$419.15	$257.04	$1,984.76								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$100.24	$99.66								$80.44	$80.44	$99.66	$100.24	$100.24	$100.24	$561.26	$1,162.70
Headblock	$0.2642	$0.2627								$123.80	$123.80	$105.08	$56.27	$96.17	$105.68	$610.80	$2,196.00
Tailblock	$0.1745	$0.1735								$175.38	$61.52	$2.43	$0.00	$0.00	$52.18	$291.50	$2,276.27
HB Threshold	400	400															
Total Base Rate Amount			$460.94	$639.80	$759.68	$905.91	$783.59	$621.48	$4,171.40	$379.62	$265.76	$207.17	$156.51	$196.41	$258.10	$1,463.57	$5,634.97
CGA Rate - (Seasonal)			$0.9665	$0.9665	$0.9665	$0.9665	$0.9665	$0.9665	$0.9665	$0.6727	$0.6329	$0.6205	$0.6082	$0.6082	$0.6082	$0.6366	$0.9092
CGA amount			$1,500.97	$2,491.64	$3,155.62	$3,965.55	$3,288.03	$2,390.15	$16,791.97	$846.26	$443.66	$256.89	$129.55	$221.38	$425.13	$2,322.87	$19,114.84
LDAC			$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0209
LDAC amount			$30.13	$50.01	$63.34	$79.60	$66.00	$47.98	$337.06	$34.97	$19.49	$11.51	$5.92	$10.12	$19.43	$101.44	$438.50
Total Bill			**$1,992.04**	**$3,181.45**	**$3,978.65**	**$4,951.06**	**$4,137.62**	**$3,059.61**	**$21,300.43**	**$1,260.84**	**$728.92**	**$475.57**	**$291.98**	**$427.91**	**$702.66**	**$3,887.88**	**$25,188.31**

November 1, 2009 - April 30, 2010
C&I High Winter Use Medium G-42

			Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter:																	
Cust. Chg	$80.44		$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$482.64								
Headblock	$0.3095		309.50	309.50	309.50	309.50	309.50	309.50	$1,857.00								
Tailblock	$0.2044		$113.03	$322.54	$462.97	$634.25	$490.97	$301.08	$2,324.85								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$80.44	$69.36								$69.36	$69.36	$69.36	$71.95	$80.44	$80.44	$440.91	$923.55
Headblock	$0.3095	$0.2716								$108.64	$108.64	$108.64	$59.73	$112.66	$123.80	$622.11	$2,479.11
Tailblock	$0.2044	$0.1794								$153.93	$54.00	$2.51	$0.00	$0.00	$61.12	$271.55	$2,596.40
HB Threshold	400	400															
Total Base Rate Amount			$502.97	$712.48	$852.91	$1,024.19	$880.91	$691.02	$4,664.49	$331.93	$232.00	$180.51	$131.68	$193.10	$265.36	$1,334.57	$5,999.06
CGA Rate - (Seasonal)			$1.1839	$1.1382	$1.1203	$1.0990	$1.0484	$0.9471	$1.0849	$1.1874	$1.3906	$1.4249	$1.4633	$1.1706	$1.1706	$1.2646	$1.1161
CGA amount			$1,838.60	$2,934.28	$3,657.78	$4,509.20	$3,566.66	$2,342.18	$18,848.69	$1,493.75	$974.81	$589.91	$311.68	$426.10	$818.25	$4,614.50	$23,463.19
LDAC			$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	0.0278	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0247
LDAC amount			$43.17	$71.67	$90.77	$114.06	$94.58	$68.75	$483.00	$12.71	$7.08	$4.18	$2.15	$3.68	$7.06	$36.85	$519.85
Total Bill			**$2,384.74**	**$3,718.43**	**$4,601.45**	**$5,647.45**	**$4,542.14**	**$3,101.95**	**$23,996.17**	**$1,838.38**	**$1,213.89**	**$774.60**	**$445.51**	**$622.87**	**$1,090.66**	**$5,985.92**	**$29,982.09**

DIFFERENCE:

Total Bill	**($392.70)**	**($536.98)**	**($622.81)**	**($696.39)**	**($404.52)**	**($42.34)**	**($2,695.74)**	**($577.54)**	**($484.98)**	**($299.04)**	**($153.53)**	**($194.96)**	**($388.01)**	**($2,098.04)**	**($4,793.79)**
% Change	**-16.47%**	**-14.44%**	**-13.53%**	**-12.33%**	**-8.91%**	**-1.36%**	**-11.23%**	**-31.42%**	**-39.95%**	**-38.61%**	**-34.46%**	**-31.30%**	**-35.58%**	**-35.05%**	**-15.99%**
Base Rate	($42.03)	($72.68)	($93.22)	($118.28)	($97.32)	($69.54)	($493.08)	$47.69	$33.77	$26.66	$24.83	$3.31	($7.26)	$129.00	($364.08)
% Change	-8.36%	-10.20%	-10.93%	-11.55%	-11.05%	-10.06%	-10.57%	14.37%	14.55%	14.77%	18.86%	1.71%	-2.74%	9.67%	-6.07%
CGA & LDAC	($350.67)	($464.30)	($529.58)	($578.11)	($307.20)	$27.20	($2,202.66)	($625.23)	($518.74)	($325.69)	($178.37)	($198.27)	($380.75)	($2,227.04)	($4,429.70)
% Change	-19.07%	-15.82%	-14.48%	-12.82%	-8.61%	1.16%	-11.69%	-41.86%	-53.21%	-55.21%	-57.23%	-46.53%	-46.53%	-48.26%	-18.88%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 08 - Apr 09 vs Nov 09 - Apr 10 - Commercial Rate G-52

November 1, 2009 - April 30, 2010 | **May 1, 2009 - October 31, 2009**
Commercial Rate (G-52)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter:	08/01/2009	07/01/2009															
Cust. Chg	$100.24		$100.24	$100.24	$100.24	$100.24	$100.24	$100.24	$601.44								
Headblock	$0.1505		$150.50	$150.50	$150.50	$150.50	$150.50	$150.50	$903.00								
Tailblock	$0.1021		$73.72	$110.88	$135.79	$136.10	$131.81	$89.03	$677.33								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$100.24	$99.66								$80.36	$80.36	$99.66	$100.24	$100.24	$100.24	$561.10	$1,162.54
Headblock	$0.1106	$0.1100								$145.30	$145.30	$110.00	$110.60	$110.60	$110.60	$732.40	$1,635.40
Tailblock	$0.0637	$0.0633								$42.64	$31.27	$15.64	$12.10	$13.38	$20.64	$135.66	$812.99
HB Threshold	1,000	1,000															
Total Base Rate Amount			$324.46	$361.62	$386.53	$386.84	$382.55	$339.77	$2,181.77	$268.30	$256.93	$225.30	$222.94	$224.22	$231.48	$1,429.16	$3,610.93
CGA Rate - (Seasonal)			$0.9658	$0.9658	$0.9658	$0.9658	$0.9658	$0.9658	$0.9658	$0.6707	$0.6309	$0.6185	$0.6062	$0.6062	$0.6062	$0.6249	$0.8351
CGA amount			$1,663.11	$2,014.66	$2,250.31	$2,253.21	$2,212.65	$1,807.98	$12,201.92	$1,012.76	$866.86	$771.27	$721.38	$733.50	$802.61	$4,908.37	$17,110.29
LDAC			$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0226
LDAC amount			$33.41	$40.47	$45.20	$45.26	$44.45	$36.32	$245.10	$41.98	$38.20	$34.67	$33.08	$33.64	$36.81	$218.37	$463.47
Total Bill			**$2,020.97**	**$2,416.75**	**$2,682.05**	**$2,685.31**	**$2,639.64**	**$2,184.07**	**$14,628.79**	**$1,323.03**	**$1,161.98**	**$1,031.23**	**$977.40**	**$991.36**	**$1,070.89**	**$6,555.90**	**$21,184.69**

November 1, 2009 - April 30, 2010
Commercial Rate (G-52)

			Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Winter Nov-Apr	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter:																	
Cust. Chg	$80.36		$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$482.16								
Headblock	$0.1976		197.60	197.60	197.60	197.60	197.60	197.60	$1,185.60								
Tailblock	$0.1341		$96.82	$145.63	$178.35	$178.76	$173.12	$116.94	$889.62								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$80.36	$69.29								$69.29	$69.29	$69.29	$71.87	$80.36	$80.36	$440.46	$922.62
Headblock	$0.1453	$0.1275								$127.50	$127.50	$127.50	$131.65	$145.30	$145.30	$804.75	$1,990.35
Tailblock	$0.0836	$0.0734								$37.43	$27.45	$18.13	$14.40	$17.56	$27.09	$142.06	$1,031.68
HB Threshold	1,000	1,000															
Total Base Rate Amount			$374.78	$423.59	$456.31	$456.72	$451.08	$394.90	$2,557.38	$234.22	$224.24	$214.92	$217.92	$243.22	$252.75	$1,387.27	$3,944.65
CGA Rate - (Seasonal)			$1.1826	$1.1369	$1.1190	$1.0977	$1.0471	$0.9461	$1.0880	$1.1867	$1.3899	$1.4240	$1.4624	$1.1700	$1.1700	$1.2963	$1.1679
CGA amount			$2,036.44	$2,371.57	$2,607.27	$2,560.93	$2,398.91	$1,771.10	$13,746.22	$1,791.92	$1,909.72	$1,775.73	$1,740.26	$1,415.70	$1,549.08	$10,182.40	$23,928.62
LDAC			$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	0.0278	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0101	$0.0210
LDAC amount			$47.87	$57.99	$64.77	$64.86	$63.69	$52.04	$351.23	$15.25	$13.88	$12.59	$12.02	$12.22	$13.37	$79.34	$430.56
Total Bill			**$2,459.09**	**$2,853.16**	**$3,128.36**	**$3,082.51**	**$2,913.68**	**$2,218.04**	**$16,654.82**	**$2,041.39**	**$2,147.84**	**$2,003.24**	**$1,970.20**	**$1,671.14**	**$1,815.20**	**$11,649.01**	**$28,303.83**

DIFFERENCE:

Total Bill	**($438.12)**	**($436.41)**	**($446.31)**	**($397.20)**	**($274.03)**	**($33.97)**	**($2,026.04)**	**($718.36)**	**($985.86)**	**($972.01)**	**($992.79)**	**($679.78)**	**($744.30)**	**($5,093.11)**	**($7,119.15)**
% Change	**-17.82%**	**-15.30%**	**-14.27%**	**-12.89%**	**-9.41%**	**-1.53%**	**-12.16%**	**-35.19%**	**-45.90%**	**-48.52%**	**-50.39%**	**-40.68%**	**-41.00%**	**-43.72%**	**-25.15%**
Base Rate	($50.32)	($61.97)	($69.78)	($69.88)	($68.53)	($55.12)	($375.61)	$34.07	$32.68	$10.38	$5.02	($19.00)	($21.27)	$41.89	($333.72)
% Change	-13.43%	-14.63%	-15.29%	-15.30%	-15.19%	-13.96%	-14.69%	14.55%	14.58%	4.83%	2.30%	-7.81%	-8.41%	3.02%	-8.46%
CGA & LDAC	($387.79)	($374.44)	($376.53)	($327.32)	($205.50)	$21.15	($1,650.43)	($752.43)	($1,018.55)	($982.39)	($997.82)	($660.78)	($723.04)	($5,135.00)	($6,785.43)
% Change	-19.04%	-15.79%	-14.44%	-12.78%	-8.57%	1.19%	-12.01%	-41.99%	-53.33%	-55.32%	-57.34%	-46.68%	-46.68%	-50.43%	-28.36%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Residential Heating

	Winter 2008-09	Winter 2009-10
Customer Charge	$11.46	$14.03
First 100 Therms	$0.3356	$0.2467
Excess 100 Therms	$0.1950	$0.1859
LDAC	$0.0260	$0.0404
CGA	$1.0888	$0.9663
Total Adjust	$1.1148	$1.0067

		Winter 2008-09 CGA @	Winter 2009-10 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$1.1148	$1.0067	($0.11)	-10%						
Cooking alone	5	$18.71	$20.30	$1.58	8%	$2.13	11%	-$0.61	-3%	$0.07	0%
	10	$25.96	$26.56	$0.60	2%	$1.68	6%	-$1.23	-5%	$0.14	1%
	20	$40.47	$39.10	($1.37)	-3%	$0.79	2%	-$2.45	-6%	$0.29	1%
Water Heating alone	30	$54.97	$51.63	($3.34)	-6%	-$0.10	0%	-$3.68	-7%	$0.43	1%
	45	$76.73	$70.43	($6.30)	-8%	-$1.43	-2%	-$5.51	-8%	$0.65	1%
	50	$83.98	$76.70	($7.28)	-9%	-$1.88	-2%	-$6.13	-8%	$0.72	1%
Heating Alone	80	$120.24	$108.03	($12.21)	-10%	-$4.10	-3%	-$9.19	-9%	$1.08	1%
	125	$199.72	$178.73	($21.00)	-11%	-$6.62	-3%	-$16.29	-9%	$1.91	1%
	150	$221.99	$199.00	($22.99)	-10%	-$6.78	-3%	-$18.38	-9%	$2.16	1%
	200	$287.48	$258.63	($28.85)	-10%	-$7.23	-3%	-$24.50	-9%	$2.88	1%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Variance Analysis of the Components of the 2008-09 Actual Results vs Proposed Winter 2009-10 Cost of Gas Rate

	WINTER SALES ACTUAL RESULTS (6 months actual)			**WINTER 2009-10 (6 months Proposed)**		
Therm Sales	85,630,852			84,282,098		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 7,271,527	$ 0.0849		$ 8,016,873	$ 0.0951
Purchased Gas	76,093,300	52,666,473	0.6150	74,843,563	48,398,041	0.5742
Storage Gas	12,098,430	10,116,996	0.1181	10,654,768	7,583,539	0.0900
Produced Gas	1,143,830	1,284,047	0.0150	906,391	657,484	0.0078
Hedging (Gain)/Loss		21,454,126	0.2505		13,495,675	0.1601
Total Volumes and Cost	89,335,560	$ 92,793,170	$ 1.0836	86,404,722	$ 78,151,613	$ 0.9273
Prior Period Balance		$ 2,883,321	$ 0.0337		935,450	$ 0.0111
Interest		214,858	0.0025		49,971	0.0006
Prior Period Adjustment		-	-		-	-
Broker Revenues		(1,133,985)	(0.0132)		(890,609)	(0.0106)
Refunds from Suppliers		-	-		-	-
Fuel Financing		493,309	0.0058		210,305	0.0025
Transportation CGA Revenues		2,854	0.0000		8,654	0.0001
280 Day Margin		-	-		-	-
Interruptible Sales Margin		(2,245)	(0.0000)		-	-
Capacity Release and Off System Sales Margins		(629,806)	(0.0074)		(635,528)	(0.0075)
Hedging Costs		-	-		-	-
Misc Overhead		107,832	0.0013		5,260	0.0001
Production & Storage		2,105,212	0.0246			
FPO Admin Costs		40,691	0.0005		40,691	0.0005
Indirect Gas Costs		552,561	0.0065		3,568,200	0.0423
Total Adjusted Cost		$ 97,427,771	**$ 1.1378**		$ 81,444,007	**$ 0.9663**

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ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Capacity Assignment Calculations 2009-2010
<u>Derivation of Class Assignments and Weightings</u>

Basic assumptions:

1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
  a The base use portion of the class design day demand based on base use
  b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

Line				Column A	Column B	Column C	Column D	Column E	Column F
				Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg			665	695	0.5%		182	513
2	RATE R-3-Resi Htg			63,619	67,314	46.8%		4,216	63,098
3	RATE G-41 (T)			23,956	25,390	17.7%		890	24,500
4	RATE G-51 (S)			2,724	2,852	2.0%		658	2,194
5	RATE G-42 (V)			33,583	35,553	24.7%		1,899	33,654
6	RATE G-52			4,181	4,361	3.0%		1,293	3,068
7	RATE G-43			4,641	4,905	3.4%		391	4,514
8	RATE G-53			1,805	1,901	1.3%		258	1,643
9	RATE G-54			797	830	0.6%		260	570
10									
11	Total			135,971	143,801	100.0%		10,046	133,755
12									-
13	Residential Total			64,285	68,009	**47.294%**		4,398	63,611
14	LLF Total			62,179	65,848	**45.791%**		3,179	62,669
15	HLF Total			9,507	9,944	**6.915%**		2,468	7,476
16	Total			135,971	143,801	100.0%		10,046	133,755
17									
18	C&I Breakdown								
19	LLF Total							3,179	62,669
20	HLF Total							2,468	7,476
21	Total							5,648	70,144
22									
23	C&I Breakdown Percentage								
24	LLF Total							56.293%	89.343%
25	HLF Total							43.707%	10.657%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$5,922,845	54,718	$9.0203			
30	Storage			$3,401,006	28,115	$10.0806			
31									
32	Peaking			$5,433,368					
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)			$1,316,028					
34	Subtotal Peaking Costs			$6,749,396	60,967	$9.2255			
35	Total			$16,073,247	143,800	$9.3146			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			1,087,426	10,046	$9.0203			
39	Pipeline - Remaining			4,835,419	44,672	$9.0202			
40	Storage			3,401,006	28,115	$10.0806			
41	Peaking			6,749,396	60,967	$9.2255			
42	Total			16,073,247	143,800	$9.3146			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**47.294%**	514,287	4,751	$9.0203			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**47.294%**	2,286,851	21,127	$9.0202			
48	Storage	Line 40 * Line 13 Col C	**47.294%**	1,608,466	13,297	$10.0806			
49	Peaking	Line 41 * Line 13 Col C	**47.294%**	3,192,097	28,834	$9.2255			
50	Total		**47.294%**	7,601,724	68,009	$9.3146			

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Capacity Assignment Calculations 2009-2010
Derivation of Class Assignments and Weightings

Line	Description	Source	%				Ratios for COG
51							
52							
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		573,139	5,295	$9.0203	
55	Pipeline - Remaining	Line 39 - Line 47		2,548,568	23,545	$9.0203	
56	Storage	Line 40 - Line 48		1,792,540	14,818	$10.0807	
57	Peaking	Line 41 - Line 49		3,557,300	32,133	$9.2255	
58	Total		**52.706%**	8,471,546	75,791	$9.3146	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		322,639	2,981	$9.0193	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		2,276,957	21,036	$9.0201	
64	Storage	Line 56 * Line 24 Col F		1,601,503	13,239	$10.0807	
65	Peaking	Line 57 * Line 24 Col F		3,178,185	28,708	$9.2256	
66	Total		**45.9103%**	7,379,284	65,964	$9.3224	**1.0008**
67			56.293%	87%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		250,500	2,314	$9.0212	
71	Pipeline - Remaining	Line 55 - Line 63		271,611	2,509	$9.0212	
72	Storage	Line 56 - Line 64		191,037	1,579	$10.0822	
73	Peaking	Line 57 - Line 65		379,115	3,425	$9.2242	
74	Total		**6.7955%**	1,092,263	9,827	$9.2624	**0.9944**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 9.0203	$ 9.0203	$ 9.0203	
80	Storage			$ 10.0806	$ 10.0806	$ 10.0806	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 9.3146	$ 9.3224	$ 9.2624	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			38.05%	**36.41%**	**49.08%**	
88	Storage			19.55%	**20.07%**	**16.07%**	
89	Peaking			42.40%	**43.52%**	**34.85%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			47.29%	43.89%	8.81%	100.00%
96	Storage			47.29%	47.09%	5.62%	100.00%
97	Peaking			47.29%	47.09%	5.62%	100.00%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Correction Factor Calculation

Data Source: Schedule 10B

	Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
G-41	986,565	2,215,526	3,173,986	3,311,800	2,735,313	1,641,267	14,064,458
G-42	1,395,688	2,578,990	3,394,388	3,523,453	3,069,379	2,136,357	16,098,254
G-43	124,220	189,353	208,435	256,773	267,247	226,817	1,272,844
High Winter Use	2,506,473	4,983,869	6,776,810	7,092,026	6,071,938	4,004,440	31,435,556
G-51	246,246	349,508	401,944	420,640	379,900	290,343	2,088,580
G-52	342,442	448,318	537,673	557,059	517,872	425,876	2,829,241
G-53	47,541	53,829	56,311	67,195	60,781	63,325	348,981
G-54	17,257	18,183	17,399	7,496	9,073	13,543	82,951
Low Winter Use	653,486	869,838	1,013,327	1,052,390	967,625	793,087	5,349,753
Gross Total	3,159,959	5,853,706	7,790,136	8,144,416	7,039,564	4,797,527	36,785,308

Total Sales	36,785,308	
Low Winter Use	5,349,753	
Winter Ratio for Low Winter Use =	**0.99440**	Schedule 10A p 2, ln 74
High Winter Use	31,435,556	
Winter Ratio for High Winter Use =	**1.00080**	Schedule 10A p 2, ln 66
Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(Hi	
Correction Factor =	$\boxed{\textbf{100.0131\%}}$	

Allocation Calculation for Miscellaneous Overhead

Projected Winter Sales Volume	(11/1/09 - 4/30/10)	83,801,811	Sch.10B
Projected Annual Sales Volume	(11/1/09 - 10/31/10)	105,710,244	Sch.10B
Percentage of Winter to Annual Sales		79.28%	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **2009 - 2010 Winter Cost of Gas Filing**
5

6		**Dry Therms**														
7	**Firm Sales**							**Subtotal**							**Subtotal**	
8		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**PK 09-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**OP 10**	**Total**
9	R-1	81,513	115,779	134,964	121,522	117,448	104,182	675,408	90,070	69,955	61,452	51,744	41,572	61,110	375,904	1,051,312
10	R-3	3,948,220	7,094,667	9,274,087	9,096,115	7,858,910	5,277,668	42,549,667	3,219,242	1,650,948	1,202,469	1,063,343	1,183,854	1,781,042	10,100,899	52,650,566
11	R-4	15,899	267,389	828,922	1,048,342	766,643	864,234	3,791,428	380,630	129,055	85,716	75,387	74,964	114,483	860,233	4,651,662
12	Total Residential.	4,045,632	7,477,835	10,237,973	10,265,978	8,743,001	6,246,084	47,016,503	3,689,942	1,849,958	1,349,637	1,190,474	1,300,391	1,956,634	11,337,037	58,353,540
13																
14	G-41	986,565	2,215,526	3,173,986	3,311,800	2,735,313	1,641,267	14,064,458	820,752	353,054	221,383	210,194	231,203	379,997	2,216,583	16,281,041
15	G-42	1,395,688	2,578,990	3,394,388	3,523,453	3,069,379	2,136,357	16,098,254	1,378,730	737,164	443,392	423,194	488,060	751,086	4,221,625	20,319,879
16	G-43	124,220	189,353	208,435	256,773	267,247	226,817	1,272,844	211,286	140,704	83,249	74,640	84,821	106,015	700,715	1,973,559
17	G-51	246,246	349,508	401,944	420,640	379,900	290,343	2,088,580	258,290	209,515	167,167	169,207	177,878	200,622	1,182,680	3,271,260
18	G-52	342,442	448,318	537,673	557,059	517,872	425,876	2,829,241	388,329	343,614	292,219	288,028	295,369	322,051	1,929,610	4,758,851
19	G-53	47,541	53,829	56,311	67,195	60,781	63,325	348,981	47,735	58,704	40,283	38,321	39,317	41,177	265,537	614,518
20	G-54	17,257	18,183	17,399	7,496	9,073	13,543	82,951	10,073	8,545	9,095	7,763	9,788	9,381	54,645	137,596
21	Total C/I	3,159,959	5,853,706	7,790,136	8,144,416	7,039,564	4,797,527	36,785,308	3,115,195	1,851,300	1,256,786	1,211,348	1,326,436	1,810,330	10,571,396	47,356,704
22																
23	**Sales Volume**	**7,205,592**	**13,331,541**	**18,028,109**	**18,410,394**	**15,782,564**	**11,043,611**	**83,801,811**	**6,805,137**	**3,701,258**	**2,606,423**	**2,401,822**	**2,626,827**	**3,766,964**	**21,908,432**	**105,710,244**
24																
25	Transportation Sales															
26																
27	G-41	127,725	214,833	414,963	447,867	412,551	218,139	1,836,079	111,993	68,653	54,105	49,679	53,550	67,385	405,365	2,241,443
28	G-42	596,372	946,132	2,097,013	2,151,423	2,015,736	1,021,944	8,828,621	513,972	291,133	194,312	176,003	196,255	280,870	1,652,545	10,481,166
29	G-43	380,510	524,389	649,086	968,958	1,062,912	757,721	4,343,575	345,806	307,302	185,252	170,812	193,090	199,889	1,402,151	5,745,726
30	G-51	33,804	45,973	64,604	72,001	69,313	50,663	336,359	36,002	26,908	25,942	22,143	23,130	26,739	160,864	497,223
31	G-52	118,842	147,819	234,828	288,355	266,433	184,754	1,241,031	118,754	118,866	102,231	105,302	113,578	110,270	669,000	1,910,031
32	G-53	627,766	674,412	744,719	1,019,931	885,070	837,507	4,789,404	669,075	834,954	569,880	544,539	551,913	544,129	3,714,490	8,503,894
33	G-54	1,596,798	1,572,310	1,505,121	697,166	743,498	1,357,231	7,472,124	1,504,406	1,342,206	1,370,496	1,213,162	1,455,520	1,380,539	8,266,329	15,738,454
34																
35	Total Trans. Sales	**3,481,817**	**4,125,867**	**5,710,334**	**5,645,702**	**5,455,513**	**4,427,960**	**28,847,194**	**3,300,007**	**2,990,022**	**2,502,219**	**2,281,640**	**2,587,034**	**2,609,822**	**16,270,745**	**45,117,939**
36																
37	Total All Sales	**10,687,409**	**17,457,408**	**23,738,443**	**24,056,096**	**21,238,078**	**15,471,572**	**112,649,005**	**10,105,145**	**6,691,280**	**5,108,643**	**4,683,462**	**5,213,861**	**6,376,786**	**38,179,177**	**150,828,182**

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11A**

Volumes (Therms) **Normal Year**

For the Months of November 09 - April 10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	1,020,327	1,054,338	1,054,338	952,306	1,054,338	1,020,327	6,155,975
Niagara Supply	796,706	777,149	783,101	638,555	820,513	98,632	3,914,656
TGP Supply (Direct)	5,448,548	5,669,619	5,692,576	5,103,337	5,692,576	5,212,172	32,818,830
Dracut Winter Supply 1- Baseload	-	6,530,945	6,530,945	5,899,193	-	-	18,961,083
Dracut Winter Supply 2- Peaking	4,544,708	151,349	599,442	174,306	6,274,163	5,858,380	17,602,348
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	23,808	124,990	407,281	244,879	49,316	-	850,273
Propane Truck	-	-	-	-	-	-	0
PNGTS	62,070	79,926	93,530	73,974	70,573	49,316	429,388
Granite Ridge	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	11,896,167	14,388,316	15,161,214	13,086,549	13,961,479	12,238,827	80,732,552
Storage Gas:							
TGP Storage	-	2,564,423	4,911,176	3,179,170	-	-	10,654,768
Produced Gas:							
LNG Vapor	23,808	124,990	442,992	265,285	24,658	24,658	906,391
Propane	-	-	-	-	-	-	0
Subtotal Produced Gas	23,808	124,990	442,992	265,285	24,658	24,658	906,391
Less - Gas Refills:							
LNG Truck	(23,808)	(124,990)	(407,281)	(244,879)	(49,316)	-	(850,273)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(663,213)	(292,494)	-	-	-	(4,083,010)	(5,038,717)
Subtotal Refills	(687,020)	(417,484)	(407,281)	(244,879)	(49,316)	(4,083,010)	(5,888,989)
Total Sendout Volumes	11,232,954	16,660,245	20,108,101	16,286,125	13,936,821	8,180,475	86,404,722

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11B**

Volumes (Therms) **Design Year**

For the Months of November 09 - April 10

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	1,020,327	1,054,338	1,054,338	952,306	1,054,338	1,020,327	6,155,975
Niagara Supply	796,706	823,064	822,214	699,775	823,064	216,820	4,181,642
TGP Supply (Direct)	5,448,548	5,681,523	5,692,576	5,141,600	5,692,576	5,193,466	32,850,290
Dracut Winter Supply 1- Baseload	-	6,530,945	6,530,945	5,899,193	-	-	18,961,083
Dracut Winter Supply 2- Peaking	5,349,916	886,835	1,882,504	1,021,178	7,280,886	6,343,885	22,765,204
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	23,808	24,658	632,603	119,038	49,316	-	849,423
Propane Truck	-	-	-	-	-	-	0
PNGTS	62,070	79,926	93,530	73,974	70,573	49,316	429,388
Granite Ridge	-	33,161	268,686	66,321	-	-	368,168
Other Purchased Resources	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	12,701,375	15,114,449	16,977,397	13,973,383	14,970,753	12,823,814	86,561,172
Storage Gas:							
TGP Storage	-	3,332,219	5,477,457	3,939,314	196,413	-	12,945,403
Produced Gas:							
LNG Vapor	23,808	24,658	632,603	174,306	24,658	24,658	904,690
Propane	-	-	95,231	-	-	-	95,231
Subtotal Produced Gas	23,808	24,658	727,834	174,306	24,658	24,658	999,921
Less - Gas Refills:							
LNG Truck	(23,808)	(24,658)	(632,603)	(119,038)	(49,316)	-	(849,423)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(663,213)	(148,798)	-	-	-	(4,282,824)	(5,094,835)
Subtotal Refills	(687,020)	(173,456)	(632,603)	(119,038)	(49,316)	(4,282,824)	(5,944,257)
Total Sendout Volumes	12,038,162	18,297,871	22,550,085	17,967,965	15,142,508	8,565,648	94,562,239

ENERGY NORTH NATURAL GAS, INC. **Schedule 11C**

d/b/a National Grid NH

Peak 2009 - 2010 Winter Cost of Gas Filing

Capacity Utilization

Volumes (Therms)

	Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
Pipeline Gas:								
Dawn Supply	6,155,975	4,000	7,240,000	85%	6,155,975	4,000	7,240,000	85%
Niagara Supply	3,914,656	3,122	5,650,820	69%	4,181,642	3,122	5,650,820	74%
TGP Supply (Direct)	32,818,830	21,596	39,088,760	84%	32,850,290	21,596	39,088,760	84%
Dracut Winter Supply 1- Baseloa	18,961,083	5,000	9,050,000	210%	18,961,083	5,000	9,050,000	210%
Dracut Winter Supply 2- Peakin	17,602,348	25,000	45,250,000	39%	22,765,204	25,000	45,250,000	50%
City Gate Delivered Supply	-	8,000	12,080,000	0%	-	8,000	12,080,000	0%
LNG Truck	850,273	-	-	-	849,423	-	-	-
Propane Truck	-	-	-	-	-	-	-	-
PNGTS	429,388	1,000	1,810,000	24%	429,388	1,000	1,810,000	24%
Granite Ridge	-	-	-	-	368,168	-	-	0%
VPEM	-	-	-	-	-	-	-	0%
Subtotal Pipeline Volumes	80,732,552				86,561,172			
Storage Gas:								
TGP Storage	10,654,768		25,801,310	41%	12,945,403		25,801,310	50%
Produced Gas:								
LNG Vapor	906,391				904,690			
Propane	-				95,231			
Subtotal Produced Gas	906,391				999,921			
Less - Gas Refills:								
LNG Truck	(850,273)				(849,423)			
Propane	-				-			
TGP Storage Refill	(5,038,717)				(5,094,835)			
Subtotal Refills	(5,888,989)				(5,944,257)			
Total Sendout Volumes	86,404,722				94,562,239			

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ENERGY NORTH NATURAL GAS, INC. **Schedule 11D**
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2009 / 10 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a National Grid New Hampshire

80 EDD at Manchester, N.H.

Requirements

Firm Sales	1,222,692
Interruptible Sales	0
Firm Transportation	215,308
Interruptible Transportation	0
Total Requirements	1,438,000

Resources

Purchased Pipeline Gas	939,900
Underground Storage Gas	281,100
Propane Air Production	111,700
LNG Produced Gas	105,300
Third-Party Supply	0
Total Resources	1,438,000

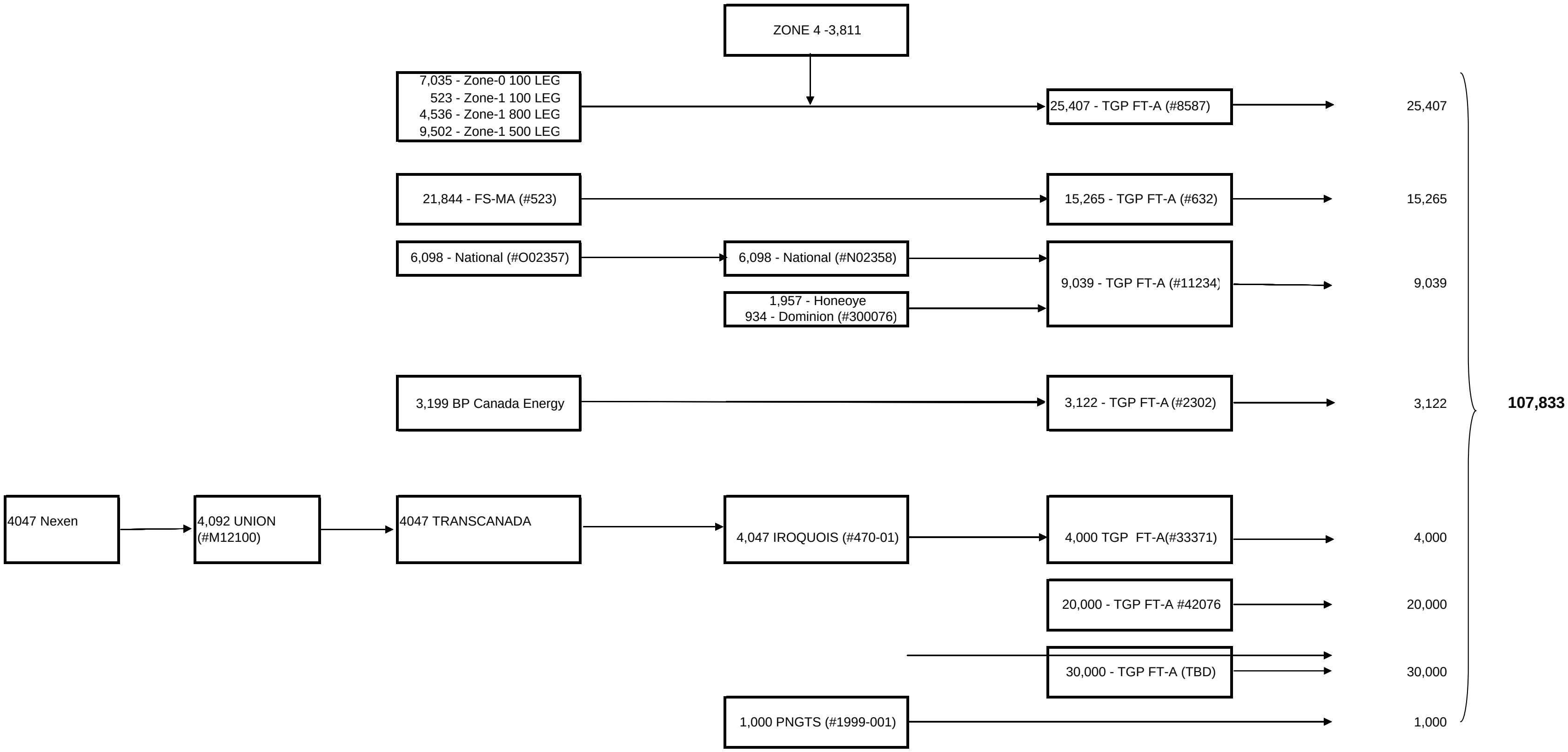
Please refer to the ENGI 2006 IRP filing (DG 06-105) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Theodore Poe, Jr.
Manager, Energy Planning

Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Granite Ridge Energy, LLC (Formerly AES Londonderry, L.L.C.)	-	-	Supply	15,000	450,000	09/30/09	N/a	Mutually agreed upon.
BP Gas & Power Canada, Ltd	-	-	Supply	3,199	1,167,635	03/31/2012	N/a	Terminates
TBD			Supply	4,047	611,097	10/31/2009	N/a	Terminates
Distrigas of Massachusetts Corp.	FLS	FLS164	Liquid Refill	7 Trucks	50,000	TBD	N/a	Terminates
Distrigas of Massachusetts Corp.	FLS	FLS160	Liquid Refill	Up to 15 trucks	1,000,000 KeySpan Total	10/31/2010	-	Terminates
TBD			Supply	TBD	TBD	TBD	N/a	Terminates
Eastern Propane Gas			Propane Supply	Monthly Take Quantity	TBD	TBD	N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	03/31/2011	03/31/2009	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	04/01/1995	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	03/31/2008	03/31/2010	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	03/31/2008	03/31/2010	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	10/31/2011	10/31/2010	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2010	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	TBD	Transportation	30,000	10,950,000	09/30/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	33371	Transportation	4,000	1,460,000	10/31/2011	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2010	10/31/2009	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2016	04/30/2016	Evergreen Provision
Union Gas Limited	M12	M12100	Transportation	4,092	1,493,580	10/31/2017	10/31/2015	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2008 - Apr 2009 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	16,432,792	34.53%	87.87%
G-42	20,486,044	43.04%	65.90%
G-43	1,971,414	4.14%	25.32%
G-51	3,296,520	6.93%	86.75%
G-52	4,789,034	10.06%	71.23%
G-53	573,498	1.21%	6.24%
G-54	33,929	0.07%	0.44%
G-63	8,936	0.02%	0.11%
Total C/I	47,592,169	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	2,267,526	4.96%	12.13%
G-42	10,601,754	23.20%	34.10%
G-43	5,814,643	12.73%	74.68%
G-51	503,411	1.10%	13.25%
G-52	1,934,090	4.23%	28.77%
G-53	8,615,180	18.86%	93.76%
G-54	7,736,444	16.93%	99.56%
G-63	8,215,853	17.98%	99.89%
Total C/I	45,688,902	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	18,700,318	20.05%	100.00%
G-42	31,087,798	33.33%	100.00%
G-43	7,786,057	8.35%	100.00%
G-51	3,799,931	4.07%	100.00%
G-52	6,723,124	7.21%	100.00%
G-53	9,188,678	9.85%	100.00%
G-54	7,770,374	8.33%	100.00%
G-63	8,224,789	8.82%	100.00%
Total C/I	93,281,071	100.00%	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak	**Peak**	**Total**	
	May 08 - Oct 08	**Nov 08-Apr 09**	**May 08 - Apr 09**	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	19,322,670	67,302,240	86,624,910	
All Others	2,059,960	22,033,320	24,093,280	
	21,382,630	89,335,560	110,718,190	
				Ratio
Total Winter Supplies				89,335,560
Total Pipeline Deliveries				86,624,910
Ratio Winter Supplies to Pipeline Supplies				1.031

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

C&I Sales Normalized (Therms)	Jul-08	Aug-08	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	206,515	248,284	454,799	16,969,499	2.68%
G-42	418,614	409,157	827,771	23,551,801	3.51%
G-43	61,213	50,089	111,303	4,581,455	2.43%
G-51	163,272	169,448	332,721	3,377,927	9.85%
G-52	289,083	280,327	569,410	5,241,686	10.86%
G-53	23,777	20,167	43,943	431,074	10.19%
G-54	-	-	-	-	0.00%
G-63	-	-	-	-	0.00%
Total C/I	1,162,475	1,177,472	2,339,947	54,153,442	4.32%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Storage Inventory, Undergound, LPG and LNG including Calculat

Underground Storage Gas

		May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Actual)	Aug-09 (Estimate)	Sep-09 (Estimate)	Oct-09 (Estimate)	Nov-09 (Estimate)	Dec-09 (Estimate)	Jan-10 (Estimate)	Feb-10 (Estimate)	Mar-10 (Estimate)	Apr-10 (Estimate)	Total
Beginning Balance (MMBtu)		1,434,776	616,939	636,806	653,437	653,437	712,074	2,278,885	2,345,206	2,118,013	1,626,896	1,308,979	1,308,979	1,434,776
Injections (MMBtu)	Sch 11A ln 37 /10	49,970	23,975	16,631	-	58,637	58,637	66,321	29,249	-	-	-	408,301	711,722
Subtotal		1,484,746	640,914	653,437	653,437	712,074	770,711	2,345,206	2,374,456	2,118,013	1,626,896	1,308,979	1,717,280	
Sempra Sale		(858,678)					1,508,184							
Withdrawals (MMBtu)	Sch 11A ln 27 /10	(9,129)	(4,108)	-	-	-	-	-	(256,442)	(491,118)	(317,917)	-	-	(1,078,714)
Ending Balance (MMBTu)		616,939	636,806	653,437	653,437	712,074	2,278,895	2,345,206	2,118,013	1,626,896	1,308,979	1,308,979	1,717,280	1,067,784
Beginning Balance		$ 11,570,325	$ 4,513,452	$ 4,579,716	$ 4,635,477	$ 4,635,477	$ 4,864,307	$ 14,856,620	$ 15,102,410	$ 13,566,186	$ 10,420,506	$ 8,384,201	$ 8,384,201	$ 11,570,325
Injections	ln 11 * ln 36	181,821	95,807	55,761	-	228,830	251,061	245,790	115,186	-	-	-	2,257,911	3,432,167
Subtotal		$ 11,752,146	$ 4,609,259	$ 4,635,477	$ 4,635,477	$ 4,864,307	$ 5,115,368	$ 15,102,410	$ 15,217,596	$ 13,566,186	$ 10,420,506	$ 8,384,201	$ 10,642,112	
Sempra Sale		$ (7,166,436)					$ 9,741,252							
Withdrawals	ln 17 * ln 34	$ (72,258)	$ (29,543)	$ -	$ -	$ -	$ -	$ -	$ (1,651,410)	$ (3,145,680)	$ (2,036,305)	$ -	$ -	(6,935,196)
Ending Balance		$ 4,513,452	$ 4,579,716	$ 4,635,477	$ 4,635,477	$ 4,864,307	$ 14,856,620	$ 15,102,410	$ 13,566,186	$ 10,420,506	$ 8,384,201	$ 8,384,201	$ 10,642,112	$ 8,067,296
Average Rate For Withdrawals	ln 18 /ln 9	$7.9153	$7.1917	$7.0940	$7.0940	$6.8312	$6.6372	$6.5192	$6.4397	$6.4051	$6.4051	$6.4051	$6.4051	
TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$3.6386	$3.9961	$3.3528		$3.9025	$4.2816	$3.7061	$3.9381	$3.1533	$3.6034	$4.6426	$5.5300	
For Informational Purposes								Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Summer Hedge Contracts - Vols Dth								57,700	57,700	57,700	57,700	57,700	57,700	346,200
Average Hedge Price								$8.7373	$8.7373	$8.7373	$8.7373	$8.7373	$8.7373	
NYMEX								$3.3210	$4.0023	$4.1261	$4.2398	$4.3184	$4.4511	
Hedged Volumes at Hedged Price								$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 3,024,840
Less Hedged Volumes at NYMEX								191,622	230,935	238,074	244,636	249,172	256,830	1,411,269
Hedge (Savings)/Loss								$ 312,518	$ 273,205	$ 266,066	$ 259,504	$ 254,968	$ 247,310	$ 1,613,571
Month Dollar Average	ln (22 + ln 32) /2				$ 4,635,477	$ 4,749,892	$ 9,860,463	$ 14,979,515	$ 14,334,298	$ 11,993,346	$ 9,402,354	$ 8,384,201	$ 9,513,156	
Money Pool Finance Rate (per Nov 08 - Apr 09 Actuals)					3.18%	3.14%	3.56%	3.86%	1.63%	1.30%	0.72%	0.68%	0.52%	
Inventory Finance Charge	ln 47 * ln 49				$ 12,295	$ 12,435	$ 29,237	$ 48,170	$ 19,436	$ 12,967	$ 5,637	$ 4,729	$ 4,109	
Financial Expenses					501	501	501	501	502	503	504	505	506	
Total Inventory Finance Charges					$ 12,796	$ 12,936	$ 29,738	$ 48,671	$ 19,938	$ 13,470	$ 6,141	$ 5,234	$ 4,615	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculat**

58 **Liquid Propane Gas (LPG)**

Ln			May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Estimate)	Aug-09 (Estimate)	Sep-09 (Estimate)	Oct-09 (Estimate)	Nov-09 (Estimate)	Dec-09 (Estimate)	Jan-10 (Estimate)	Feb-10 (Estimate)	Mar-10 (Estimate)	Apr-10 (Estimate)	Total
61	Beginning Balance		138,535	138,019	137,862	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	138,535
63	Injections	Sch 11A ln 36 /10	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Subtotal		138,535	138,019	137,862	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	
67	Withdrawals	Sch 11A ln 31 /10	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Adjustment for change in temperature		(516)	(157)	(7)				-	-	-	-	-	-	(680)
71	Ending Balance		138,019	137,862	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855	137,855
74	Beginning Balance		$ 2,025,578	$ 2,018,028	$ 2,015,733	$ 2,015,634	$ 2,015,634	$ 2,015,634	2,015,634	2,015,634	2,015,634	2,015,634	2,015,634	2,015,634	2,025,578
76	Injections	ln 63 * ln 86	-	-	-	-	-	-	-	-	-	-	-	-	-
78	Subtotal		$ 2,025,578	$ 2,018,028	$ 2,015,733	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	
80	Withdrawals	ln 49 * ln 70	(7,551)	(2,294)	(99)	-	-	-	-	-	-	-	-	-	(9,944)
82	Ending Balance		$ 2,018,028	$ 2,015,733	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634
84	Average Rate For Withdrawals		$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	$14.6214	
86	Propane Rate for Injections	Actual or Sch. 6, ln 150 * 10	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$7.4000	$7.4900	$7.5600	$7.6600	$7.7700	$7.8800	
89	Month Dollar Average	ln (74 + ln 82) /2				$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	$ 2,015,634	
91	Money Pool Finance Rate (per Nov 08 - Apr 09 Actuals)					3.18%	3.14%	3.56%	3.86%	1.63%	1.30%	0.72%	0.68%	0.52%	
93	Inventory Finance Charge	ln 89 * ln 91				$ 5,346	$ 5,277	$ 5,976	$ 6,482	$ 2,733	$ 2,179	$ 1,208	$ 1,137	$ 871	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Storage Inventory, Undergound, LPG and LNG including Calculat

Line	Liquid Natural Gas (LNG)		May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Estimate)	Aug-09 (Estimate)	Sep-09 (Estimate)	Oct-09 (Estimate)	Nov-09 (Estimate)	Dec-09 (Estimate)	Jan-10 (Estimate)	Feb-10 (Estimate)	Mar-10 (Estimate)	Apr-10 (Estimate)	Total
101	Beginning Balance		9,001	7,134	6,727	6,700	6,700	6,700	6,700	6,700	6,700	3,129	1,088	3,554	9,001
103	Injections	Sch 11A ln 35 /10	-	1,718	1,809	-	-	-	2,381	12,499	40,728	24,488	4,932	-	88,554
105	Subtotal		9,001	8,852	8,536	6,700	6,700	6,700	9,081	19,199	47,428	27,617	6,020	3,554	
107	Withdrawals	Sch 11A ln 30 /10	(1,867)	(2,125)	(1,836)	-	-	-	(2,381)	(12,499)	(44,299)	(26,529)	(2,466)	(2,466)	(96,467)
109	Ending Balance		7,134	6,727	6,700	6,700	6,700	6,700	6,700	6,700	3,129	1,088	3,554	1,088	1,088
112	Beginning Balance		$ 70,197	$ 56,376	$ 49,631	$ 48,378	$ 48,378	$ 48,378	$ 48,378	43,794	38,684	17,691	6,166	20,012	70,197
114	Injections	ln 103 * ln 124	(1,233)	8,934	12,003	-	-	-	10,978	67,056	229,476	138,786	27,731	-	493,730
116	Subtotal		$ 68,964	$ 65,310	$ 61,635	$ 48,378	$ 48,378	$ 48,378	$ 59,356	$ 110,850	$ 268,160	$ 156,476	$ 33,896	$ 20,012	
118	Withdrawals	ln 107 * ln 122	(12,588)	(15,678)	(13,257)	-	-	-	(15,562)	(72,166)	(250,469)	(150,311)	(13,884)	(13,884)	(557,800)
120	Ending Balance		$ 56,376	$ 49,631	$ 48,378	$ 48,378	$ 48,378	$ 48,378	$ 43,794	$ 38,684	$ 17,691	$ 6,166	$ 20,012	$ 6,127	$ 6,127
122	Average Rate For Withdrawals		$7.6619	$7.3779	$7.2206	$7.2206	$7.2206	$7.2206	$6.5364	$5.7738	$5.6540	$5.6660	$5.6308	$5.6308	
124	LNG Rate for Injections	Actual or Sch. 6, ln 149 * 10	$4.6111	$5.2000	$6.6354	$5.6675	$5.6231	$5.5630	$4.6111	$5.3649	$5.6343	$5.6675	$5.6231	$5.5630	
127	Month Dollar Average	ln (112 + ln 120) /2				$ 48,378	$ 48,378	$ 48,378	$ 46,086	$ 41,239	$ 28,187	$ 11,928	$ 13,089	$ 13,070	
129	Money Pool Finance Rate (per Nov 08 - Apr 09 Actuals)					3.18%	3.14%	3.56%	3.86%	1.63%	1.30%	0.72%	0.68%	0.52%	
131	Inventory Finance Charge	ln 127 * ln 129				$ 128	$ 127	$ 143	$ 148	$ 56	$ 30	$ 7	$ 7	$ 6	
134	Total Fuel Financing	lns 53 + 93 + 131				$ 18,270	$ 18,339	$ 35,857	$ 55,301	$ 22,727	$ 15,680	$ 7,357	$ 6,378	$ 5,491	

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2009 - 2010 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculat**
5

Line			May	June	Jul	Aug	Sep	Oct	Total
137									
138	Summer Hedge Program								
139			May	June	Jul	Aug	Sep	Oct	Total
140	Trade Dates	Contracts	(a)	(b)	(c)	(d)	(e)	(f)	(g)
141	02-May-08								
142	16-May-08								
143	06-Jun-08								
144	20-Jun-08								
145	11-Jul-08								
146	25-Jul-08								
147	08-Aug-08								
148	25-Aug-08								
149	05-Sep-08								
150	19-Sep-08								
151	20-Oct-08								
152	07-Nov-08								
153	21-Nov-08								
154	30-Dec-08								
155			57,700	57,700	57,700	57,700	57,700	57,700	346,200
156									
157		Prices							
158	02-May-08								
159	16-May-08								
160	06-Jun-08								
161	20-Jun-08								
162	11-Jul-08								
163	25-Jul-08								
164	08-Aug-08								
165	25-Aug-08								
166	05-Sep-08								
167	19-Sep-08								
168	20-Oct-08								
169	07-Nov-08								
170	21-Nov-08								
171	30-Dec-08								
172									
173		Dollars							
174	02-May-08								
175	16-May-08								
176	06-Jun-08								
177	20-Jun-08								
178	11-Jul-08								
179	25-Jul-08								
180	08-Aug-08								
181	25-Aug-08								
182	05-Sep-08								
183	19-Sep-08								
184	20-Oct-08								
185	07-Nov-08								
186	21-Nov-08								
187	30-Dec-08								
188			$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 3,024,840
189									
190	Average Hedge Contract Price		8.7373	8.7373	8.7373	8.7373	8.7373	8.7373	8.7373
191	NYMEX		3.3210	3.5380	3.9490	3.3790	3.4569	3.7786	3.5704
192									
193	Hedged Volumes at Hedged Price		$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 504,140	$ 3,024,840
194	Less Hedged Volumes at NYMEX		191,622	204,143	227,857	194,968	199,461	218,025	1,236,076
195	Hedge (Savings)/Loss		$ 312,518	$ 299,997	$ 276,283	$ 309,172	$ 304,679	$ 286,115	1,788,764
196									
197	Options Loss		$ 21,174	$ 20,899	$ 14,896	22,600			$ 79,569
198									
199	Total		$ 333,692	$ 320,896	$ 291,179	$ 331,772	$ 304,679	$ 286,115	$ 1,868,333
200									

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-09	3,481,817	-$0.0003	$ (1,045)
Dec-09	4,125,867	-0.0003	(1,238)
Jan-10	5,710,334	-0.0003	(1,713)
Feb-10	5,645,702	-0.0003	(1,694)
Mar-10	5,455,513	-0.0003	(1,637)
Apr-10	4,427,960	-0.0003	(1,328)
Total	**28,847,194**		**$ (8,654)**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed First Revised Page 89 for calculation of rate.

nationalgrid

July 29, 2009

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: DG 08-106
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
2008-09 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Attached is the redacted version of the 2008-09 Winter Period Cost of Gas reconciliation filing for EnergyNorth Natural Gas, Inc d/b/a National Grid NH ("the Company"). This filing is being submitted under protective order and confidential treatment granted by the Commission in Order No. 24,909 dated October 29, 2008 in Docket DG 08-106. This report has been filed electronically with the New Hampshire Public Utilities Commission in accordance with Order Number 24,223 issued on October 24, 2003, in which the Commission found that the filing requirement would be satisfied by filing one electronic copy and one paper copy with the Commission. The Company has also filed separately a confidential version with the Commission via an overnight parcel service.

The filing shows an under collection for the 2008-09 Winter Period of $935,450 summarized as follows:

Winter Period Beginning Balance	$2,883,321
Less: Cost of Gas Revenue Billed	($95,997,524)
Add: Cost of Gas Allowable (5/1/08 -10/31/08)	$719,217
Add: Cost of Gas Allowable (11/1/08 -4/30/09)	$93,330,435
Winter Period Ending Balance	$935,450

This filing consists of a six-page summary and nine supporting schedules. Page 1 of the Summary compares the actual deferred gas costs to the projections submitted in the Company's filing including the beginning balance, interest and other allowable adjustments to gas costs, gas costs and gas cost revenue. The result is a net under collection of $935,450. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's filing resulting in over collections of $212,161 and $63,719, respectively, for a net under collection for all the gas accounts of $659,570. The Bad Debt and Working Capital over collections are the result of the New Hampshire Commission approving the Settlement Agreement in DG 07-050, Order No. 24,858 dated May 23, 2008, which revised the Bad Debt percent from 2.56% to 2% effective November 1, 2006 and 1.75% effective November 1, 2007, plus the Working Capital percent from .967% to .645% effective May 1, 2007. Page 3 of the Summary compares actual demand charges of $7,271,527 to the $7,758,721 in demand charges estimated in the filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $85,521,642 compared to $95,969,537 in the filing. The $10,447,895 decrease in commodity costs was caused mainly by lower sendout volumes and prices than originally forecast. The results show that the actual demand and commodity costs were $10,935,088 lower than filed. Page 5 of the Summary provides a variance analysis that explains how much of the difference between actual costs and forecasted costs is due to weather $352,280 changes in demand ($6,161,253) and changes in gas prices ($5,126,115). Page 6 of the Summary shows the calculation of the actual Transportation Cost of Gas Revenue compared to the filing.

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The attached Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost collections, and interest applied. The third page of Schedule 1 provides the same information for bad debt associated with the cost of gas. Schedule 2 provides the details of gas cost by source. Schedule 3 provides the detailed calculation of winter gas cost revenue billed by rate class. Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the winter cost of gas account. Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital. It shows the monthly beginning account balances, working capital allowable, the working capital collections and the interest applied to derive the monthly ending balances. Schedule 6 shows the bad debt and working capital calculation that determines the amount of expense booked for those items. Schedule 7 provides the backup calculations for the revenue billed to recover working capital and bad debt by rate class. Schedule 8 provides a summary of the monthly commodity costs and related volumes. Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

Please return one copy of this filing to me bearing the Commission's receipt stamp in the envelope that has been provided for your convenience.

Please contact me by phone at 781-907-1809, or by e-mail at thomas.p.oneill@us.ngrid.com or Ann Leary by phone at 781-907-1836, or e-mail at Ann.Leary@us.ngrid.com , if you have any further questions.

Yours truly,

Thomas P. O'Neill

Enclosures

cc: Meredith A. Hatfield, Esq.
Steven V. Camerino, Esq.
Thomas P. O'Neill, Esq.
Ann E. Leary

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2008-2009 COST OF GAS RESULTS
DG 08-106
NOVEMBER 2008 THROUGH APRIL 2009

	Original Filing 1/	Actual		Difference
Peak Gas cost Account 175.20				
Balance 05/01/08- (Over) / Under	$2,883,321	$2,883,321	2/	$0
Peak Gas Costs 5/1/08 - 10/31/08	$1,574,761	$1,609,063	3/	34,302
Fuel Financing 5/1/08 - 10/31/08	177,319	313,736	3/	136,417
Prior Period Adjustment 5/1/08-10/31/08	-	-	3/	-
Broker Revenue 5/1/08 - 10/31/08	(833,181)	(865,776)	3/	(32,595)
280 Day Margins 5/1/08 - 10/31/08	-	-	4/	-
IT Sales Margins 5/1/08 - 10/31/08	(2,245)	(2,245)	4/	-
Off System Sales Margin 5/1/08 - 10/31/08	(60,510)	(65,772)	4/	(5,262)
Capacity Release 5/1/08 - 10/31/08	(346,961)	(356,839)	4/	(9,878)
Interest 5/1/08 - 10/31/08	86,951	87,050	3/	99
Sum 5/1/08 - 10/31/08 costs	$596,134	$719,217		$123,083
Beginning Balance 10/31/08 (Over)/Under	$3,479,455	$3,602,538		$123,083
Interest 11/1/08 - 4/30/09	293,722	185,571		(108,151)
Prior Period Adjustments	0	0		0
Interruptible Sales Margin 11/1/08 - 4/30/09	-	-		-
280-Day Margin 11/1/08 - 4/30/09	-	-		-
Off System Sales Margin 11/1/08 -4/30/09	(1,428)	(28,322)		(26,894)
Capacity Release Credits 11/1/08 - 4/30/09	(1,907)	(178,872)		(176,965)
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	36,312	40,691		4,379
Broker Revenues 11/1/08 - 4/30/09	(416,518)	(268,209)		148,309
Production & Storage	2,105,212	2,105,212		0
Misc Overhead	107,829	107,832		3
Fuel Financing 11/1/08 - 4/30/09	346,187	179,573		(166,614)
Transportation Cost of Gas Revenue	2,546	2,854		308
Total Adjustment to Costs	$2,471,955	$2,146,328		($325,627)
Gas Costs 11/1/08 - 4/30/09	102,153,497	$91,184,106		($10,969,391)
Total Gas Costs and Adjustments 11/08 -4/09	104,625,452	$93,330,435		($11,295,017)
Gas Cost Billed	($108,104,907)	(95,997,524)		$12,107,383
Total (Over) / Under 04/30/09	$0	$935,450		$935,450

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2008-2009 COST OF GAS RESULTS
DG 08-106
NOVEMBER 2008 THROUGH APRIL 2009

	Original Filing 1/	Actual		Difference
Bad Debts Account 175.52				
Beginning Balance	($1,409,904)	$30,927		$1,440,831
BD Costs 5/1/08-10/31/08	27,736	32,809	5/	5,073
Interest 5/1/08-10/31/08	(35,300)	2,401	5/	37,701
Beginning Balance 10/31/08 (Over)/Under	($1,417,468)	($1,423,906)		$1,483,604
Bad Debt Costs 11/1/08 - 4/30/09	1,844,326	1,652,823		(191,503)
Bad Debt CGA Billed	(410,427)	(428,154)		(17,727)
Adjustment		-		0
Interest	(16,431)	(12,924)		3,507
Total (Over) / Under 04/30/09	$0	($212,161)		($212,161)
Working Capital Account 142.20				
Beginning Balance	($305,654)	$15,763		$321,417
WC Costs 5/1/08-10/31/08	10,157	12,227	6/	2,070
Interest 5/1/08-10/31/08	(7,560)	1,070	6/	8,630
Beginning Balance 10/31/08 (Over)/Under	**($303,057)**	**($305,497)**		**$332,116**
Working Capital Costs 11/1/08-4/30/09	658,890	586,801		(72,089)
Working Capital CGA Billed	(353,098)	(342,523)		10,575
Adjustment	-	-		0
Interest	(2,735)	(2,499)		236
Total (Over) / Under 04/30/09	$0	($63,719)		-$63,719
Total 175.20, 175.52, 142.20	$0	$659,570		$659,570

1/ As filed 10-17-08 in the Winter 2008-2009 Cost of Gas DG 08-106

2/ The beginning balance is the sum of the actual April 30, 2008 balance $7,915,782 less the May 2008 Billings of $5,032,461.

3/ The 5/1/08 - 10/31/08 costs are per Schedule 1, page 1, of the Summer 2008 Reconciliation filed on January 30, 2009 in DG 07-129.

4/ The 5/1/08 - 10/31/08 costs are per Schedule 4, of the Summer 2008 Reconciliation filed on January 30, 2009 in DG 07-129.

5/ The 5/1/08 - 10/31/08 costs are per Schedule 1, page 3, of the Summer 2008 Reconciliation filed on January 30, 2009 in DG 07-129.

6/ The 5/1/08 - 10/31/08 costs are per Schedule 5, of the Summer 2008 Reconciliation filed on January 30, 2009 in DG 07-129.

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2008-2009 COST OF GAS RESULTS
DG 08-106
SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2008 THROUGH APRIL 2009

	Filing (a)	1/ Actual May 08 - Oct 08 (b)	Actual Nov 08 - Apr 09 (c)	Actual Total Peak Demand (d)=(b)+(c)	Difference (e)=(d)-(a)
Supplies:					
BP/Nexen					
IEC					
Subtotal Supply Demand Charges	$4,922	$0	$7,505	$7,505	$2,583
Pipelines:					
Iroquois Gas Trans	$160,191	$0	$144,288	$144,288	($15,903)
TGP NET 33371	254,640	-	228,815	228,815	($25,825)
TGP FTA Z5-Z6 2302	92,349	-	82,888	82,888	($9,461)
TGP FTA Z0 - Z6 8587	2,158,540	-	1,932,844	1,932,844	($225,696)
TGP Dracut FTA Z6 - Z6 42076	379,200	-	341,076	341,076	($38,124)
Portland Natual Gas Pipeline	164,410	-	133,382	133,382	($31,028)
ANE (Uniongas and TransCanada)	$213,253	$ -	$166,300	$166,300	($46,953)
TGP FTA 632	1,078,930	509,900	472,246	982,146	($96,784)
TGP FTA 11234	616,332	294,275	269,962	564,237	($52,095)
National Fuel	245,959	113,067	142,038	255,105	$9,146
Subtotal Pipeline Demand Charges	$5,363,804	$917,242	$3,913,839	$4,831,081	($532,723)
Peaking Supply					
Granite Ridge					
Chevron					
DOMAC					
Virginia Power Energy Marketing					
Transgas Trucking					
Subtotal Peaking Supply	$1,939,133	$120,000	$1,602,571	$1,722,571	($216,562)
Propane					
Energy North Propane	$0	$0	$72	$ 72	$72
Storage:					
Demand & Capacity Charges	$1,297,186	$ 600,522.68	$ 586,097.45	$ 1,186,620	($110,566)
Other:					
Capacity Managed	($846,324)	$ (28,701.53)	($446,845)	$ (475,546)	$370,778
PNGTS Refund	$0	$ -	($775)	$ (775)	($775)
Total Demand Charges (Forward to Page 4)	$7,758,721	$1,609,063	$5,662,464	$7,271,527	($487,194)

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2008 Cost of Gas Reconciliation, DG 07-129 filed January 30, 2009.

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2008-2009 COST OF GAS RESULTS
DG 08-106
SUMMARY OF COMMODITY COSTS FOR PERIOD
NOVEMBER 2008 THROUGH APRIL 2009

	Filing	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 3):	$7,758,721		$7,271,527		($487,194)	
TGP						
Therms						
Cost						
Spot Gas						
Therms						
Cost						
Canadian						
Therms						
Cost						
PNGTS						
Therms						
Cost						
Granite Ridge						
Therms						
Cost						
City Gate Delivered Supply						
Therms						
Cost						
DOMAC						
Therms						
Cost						
Storage gas - commodity withdrawn						
Therms						
Cost						
Propane						
Therms						
Cost						
LNG						
Therms						
Cost						
Hedging (Gains) Losses						
Other - Cashout, Broker Penalty, Canadian Managed						
Therms						
Cost						
Prior period Adj						
Subtotal:						
Volumes (net of fuel retention)	95,368,818		89,335,560		(6,033,258)	
Cost	$ 95,969,537	1.0063	$ 85,521,642	0.9573	$ (10,447,895)	(0.0490)
Total Demand and Commodity Costs	$ 103,728,258		$ 92,793,170		$ (10,935,088)	
Demand (therms):	95,368,818		89,335,560		(6,033,258)	
Firm Gas Sales	91,523,044		85,630,852		(5,892,192)	
Lost Gas (Unaccounted For)	2,302,627		2,743,476		440,849	
Unbilled Therms	1,314,044		3,107,114		1,793,070	
Fuel Retention	-		-		-	
Company Use	229,104		961,232		732,128	
Total Demand	95,368,819		92,442,674		(2,926,145)	
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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2008-2009 COST OF GAS RESULTS
DG 08-106

Weather Variance - Volume Impact	(A) Actual Volume	(B) Normal Volume	(C) Actual Rate		(A-B)*C Difference
TGP					
Spot Gas					
AES					
PNGTS					
ANE/BP NEXEN					
City Gate Delivered Supply					
DOMAC					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Volume Weather Varaince	89,335,560	88,823,203		$	352,280

Demand Variance - Commodity Costs	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate		(B-A)*C Difference
TGP					
AES Londonderry					
PNGTS					
Canadian					
City Gate Delivered Supply					
DOMAC					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Demand Variance (Less: Fuel Retention)	95,368,818	89,335,560		$	(5,808,974)
Demand Variance Net of Weather Variance					(6,161,253)

Rate Variance - Commodity Costs	(A) Actual Volume	(B) Forecast Rate	(C) Actual Rate		(C-B)*A Difference
TGP					
AES Londonderry					
PNGTS					
Canadian					
City Gate Delivered Supply					
DOMAC					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Commodity Cost Rate Variance	89,335,560			$	(15,033,861)
Demand Charge Variance (from page 3)					(487,194)
Other Rate Variance (from page 4)					
Hedging (Gains)/Losses					11,066,016
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments					(671,076)
Total Rate Variance				$	(5,126,115)
Due to Weather Variance					352,280
Due to Demand Variance (from above)					(6,161,253)
Total Gas Cost Variance				$	(10,935,088)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2008-2009 COST OF GAS RESULTS
DG 08-106

	FILING	ACTUAL
Cost of Propane	$ 1,411,827	$ 707,705
Cost of LNG	1,036,505	535,807
Total Costs	2,448,332	1,243,512
Percentage of Supplies Used For Pressure Support Purposes	14.1%	14.1%
Cost of Supplies Used For Pressure Support Purposes	345,215	175,335
Firm Therms Sold	91,523,044	85,630,852
Firm Therms Transported	25,462,089	28,535,690
Total Therms	116,985,133	114,166,542
Actual Liquid Cost/Therm	0.0030	0.0015
Firm Therms Transported	25,462,089	28,535,690
Liquid Costs Allocated to Transported Therms	75,137	43,825
Prior (Over) or under Collection	(76,753)	(76,753)
Total	(1,616)	(32,928)
Costs Recovered:		
Therms Transported	25,462,089	28,535,690
Recovery Rate	(0.0001)	(0.0001)
Costs Recovered	(1,616)	(2,854)
(Over) / Under Collection For Period	-	(30,075)

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

	FOR THE MONTH OF:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Total
	DAYS IN MONTH	30	31	31	28	31	30		
1	BEGINNING BALANCE	$ 3,602,538	$ 12,139,415	$ 13,961,774	$ 16,376,795	$ 11,720,678	$ 7,692,535	$ 4,476,672	**$ 3,602,538**
2									
3	Add: Actual Costs	11,760,788	17,781,342	24,389,414	17,089,066	12,703,257	7,460,239		**91,184,106**
4									
5	Add. FPO Admin Costs	40,691	-	-	-	-	-		**40,691**
6	Add: MISC OH	17,972	17,972	17,972	17,972	17,972	17,972		**107,832**
7	Add: Production and Storage	350,869	350,869	350,869	350,869	350,869	350,869		**2,105,212**
8	Add: Fuel Financing	65,703	73,755	34,678	28,053	14,910	13,764		**230,863.33**
9	Reverse Fuel Finance Estimate		(65,054)			(34,678)			**(99,732.36)**
10	Add new Fuel Finance Estimate		34,678			13,764			**48,441.76**
11									
12	Less: CUSTOMER BILLINGS	(3,685,779)	(16,307,530)	(22,321,694)	(22,102,941)	(17,055,026)	(10,980,478)	(3,541,223)	**(95,994,670)**
13									
14	Less: REFUND	-	-	-	-	-	-		-
15									
16	Less: Broker Revenues	(38,655)	(53,914)	(65,671)	(37,927)	(33,585)	(38,457)	-	**(268,209)**
17									
18	NON FIRM MARGIN AND CREDITS	(547)	(49,711)	(32,361)	(36,191)	(32,381)	(56,004)	-	**(207,195)**
19									
20	ENDING BALANCE PRE INTEREST	**$ 12,113,580**	**$ 13,921,822**	**$ 16,334,981**	**$ 11,685,696**	**$ 7,665,779**	**$ 4,460,440**	**$ 935,450**	**$ 749,879**
21									
22	MONTH'S AVERAGE BALANCE	7,858,059	13,030,618	15,148,377	14,031,246	9,693,229	6,076,488		
23									
24	INTEREST RATE	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%		
25									
26	INTEREST APPLIED	25,835	39,952	41,814	34,982	26,756	16,232		**185,571**
27									
28	ENDING BALANCE	**$ 12,139,415**	**$ 13,961,774**	**$ 16,376,795**	**$ 11,720,678**	**$ 7,692,535**	**$ 4,476,672**	**$ 935,450**	**$ 935,450**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.40

	FOR THE MONTH OF: DAYS IN MONTH	Nov-08 30	Dec-08 31	Jan-09 31	Feb-09 28	Mar-09 31	Apr-09 30	May-09	Total
1	BEGINNING BALANCE	$ 2,954,698	$ (1,967,865)	$ (1,973,899)	$ (1,816,523)	$ (1,694,843)	$ (1,699,521)	$ (1,704,061)	**2,954,698**
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		**$ -**
4									
5	Add: MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(4,924,183)	-	-	-	-	-	-	**(4,924,183)**
8									
9	Add: ADJUSTMENTS	-	-	162,600	126,053	-	-	-	**288,653**
10									
11	ENDING BALANCE PRE INTEREST	**$ (1,969,485)**	**$ (1,967,865)**	**$ (1,811,299)**	**$ (1,690,471)**	**$ (1,694,843)**	**$ (1,699,521)**	**$ (1,704,061)**	**$ (1,680,833)**
12									
13	MONTH'S AVERAGE BALANCE	492,606	(1,967,865)	(1,892,599)	(1,753,497)	(1,694,843)	(1,699,521)		
14									
15	INTEREST RATE	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%		
16									
17	INTEREST APPLIED	1,620	(6,034)	(5,224)	(4,372)	(4,678)	(4,540)		**(23,228)**
18									
19	ENDING BALANCE	**$ (1,967,865)**	**$ (1,973,899)**	**$ (1,816,523)**	**$ (1,694,843)**	**$ (1,699,521)**	**$ (1,704,061)**	**$ (1,704,061)**	**$ (1,704,061)**

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-08** **30**	**Dec-08** **31**	**Jan-09** **31**	**Feb-09** **28**	**Mar-09** **31**	**Apr-09** **30**	**May-09**	**Total**
1	BEGINNING BALANCE	$ (1,423,906)	$ (1,228,147)	$ (980,363)	$ (642,670)	$ (433,118)	$ (280,048)	$ (194,262)	**(1,423,906)**
2									
3	Add: COST ALLOW	215,541	320,715	437,407	308,760	231,580	138,820		**$ 1,652,823**
4									
5	Adjustment						-	-	-
6									
7	Less: CUSTOMER BILLINGS	(15,431)	(69,550)	(97,478)	(97,869)	(77,527)	(52,400)	(17,899)	**(428,154)**
8									
9	ENDING BALANCE PRE INTEREST	**$ (1,223,795)**	**$ (976,983)**	**$ (640,433)**	**$ (431,779)**	**$ (279,065)**	**$ (193,629)**	**$ (212,161)**	**$ (199,237)**
10									
11	MONTH'S AVERAGE BALANCE	(1,323,850)	(1,102,565)	(810,398)	(537,225)	(356,092)	(236,839)		
12									
13	INTEREST RATE	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%		
14									
15	INTEREST APPLIED	(4,352)	(3,380)	(2,237)	(1,339)	(983)	(633)		**$ (12,924)**
16									
17	ENDING BALANCE	**$ (1,228,147)**	**$ (980,363)**	**$ (642,670)**	**$ (433,118)**	**$ (280,048)**	**$ (194,262)**	**$ (212,161)**	**$ (212,161)**

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
OFF PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-08** **30**	**Dec-08** **31**	**Jan-09** **31**	**Feb-09** **28**	**Mar-09** **31**	**Apr-09** **30**	**May-09**	**Total**
1	BEGINNING BALANCE	$ (44,065)	$ (126,096)	$ (126,483)	$ (126,832)	$ (127,148)	$ (127,499)	$ (127,840)	**(44,065)**
2									
3	Add: COST ALLOW	-	-	-	-	-	-		**$ -**
4									
5	Less: CUSTOMER BILLINGS	(81,752)	-	-	-	-	-	-	**(81,752)**
6									
7	ENDING BALANCE PRE INTEREST	**$ (125,817)**	**$ (126,096)**	**$ (126,483)**	**$ (126,832)**	**$ (127,148)**	**$ (127,499)**	**$ (127,840)**	**$ (125,817)**
8									
9	MONTH'S AVERAGE BALANCE	(84,941)	(126,096)	(126,483)	(126,832)	(127,148)	(127,499)		
10									
11	INTEREST RATE	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%		
12									
13	INTEREST APPLIED	(279)	(387)	(349)	(316)	(351)	(341)		**(2,023)**
14									
15	ENDING BALANCE	**$ (126,096)**	**$ (126,483)**	**$ (126,832)**	**$ (127,148)**	**$ (127,499)**	**$ (127,840)**	**$ (127,840)**	**$ (127,840)**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
GAS COSTS BY SOURCE
SCHEDULE 2A

FOR THE MONTH OF:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
DEMAND							
ALBERTA NORTHEAST							
BP							
TOTAL CANADIAN	$ 32,410.35	$ 16,013.12	$ (36,695.40)	$ 21,776.92	$ (29,889.50)	$ 5,888.26	**$ 9,503.75**
PEAKING SUPPLY	21,286.22	20,724.59	60,724.59	60,654.47	61,329.09	24,287.59	249,006.55
TRANSPORT CAPACITY	601,774.75	631,661.15	632,748.02	611,863.93	651,175.68	600,744.40	**3,729,967.93**
STORAGE FIXED COSTS	90,741.59	99,218.98	84,975.76	105,693.84	106,667.60	98,799.68	**586,097.45**
LNG	197,500.00	343,925.74	270,712.87	270,712.87	270,712.87	-	**1,353,564.35**
PROPANE	-	-	39.70	3.97	15.97	11.91	**71.55**
CANADIAN CAPACITY MANAGED	(4,207.82)	(9,541.96)	(79,295.79)	(79,179.06)	(194,140.04)	(80,479.98)	**(446,844.65)**
PNGTS Refund	(775.13)	-	-	-	-	-	**(775.13)**
OTHER	500.00	500.00	500.00	500.00	500.00	500.00	**3,000.00**
CAPACITY RELEASE ADJUSTMENT	-	31,942.58	32,360.57	32,360.57	32,276.97	49,931.57	**178,872.26**
TOTAL DEMAND	**$ 939,229.96**	**$ 1,134,444.20**	**$ 966,070.32**	**$ 1,024,387.51**	**$ 898,648.64**	**$ 699,683.43**	**$ 5,662,464.06**
COMMODITY							
ALBERTA NORTHEAST							
DTE Energy							
SEMPRA							
SUBTOTAL CANADIAN COMMODITY							
PIPELINE TRANSPORT COMM.							
Distrigas							
VPEM Citigate Delivery							
GAS SUPPLY							
STORAGE COMMODITY							
LNG							
PROPANE							
OTHER COST ADJUSTMENTS							
CANDIAN CAPACITY MANAGED							
SUPPLIER CASHOUT							
NET OTHER COST ADJUSTMENTS	(133,545.88)	(130,107.72)	(382,365.78)	106,080.28	(65,181.55)	(65,955.37)	**(671,076.02)**
SUBTOTAL COMMODITY COST	**$ 10,834,908.41**	**$ 16,825,270.73**	**$ 23,423,344.12**	**$ 16,112,974.97**	**$ 11,808,617.00**	**$ 6,898,446.78**	**$ 85,903,562.01**
OFF SYSTEM SALES COST							
NON-FIRM COST							
TOTAL COMMODITY COST	**$ 10,821,557.83**	**$ 16,646,897.69**	**$ 23,423,344.12**	**$ 16,064,678.50**	**$ 11,804,608.35**	**$ 6,760,555.78**	**$ 85,521,642.27**

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
GAS COSTS SUMMARY
SCHEDULE 2A

FOR THE MONTH OF:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
Total Peak Demand	**$ 939,229.96**	**$ 1,134,444.20**	**$ 966,070.32**	**$ 1,024,387.51**	**$ 898,648.64**	**$ 699,683.43**	**$ 5,662,464.06**
Off-Peak Demand	-	-	-	-	-	-	-
Total Demand	**$ 939,229.96**	**$ 1,134,444.20**	**$ 966,070.32**	**$ 1,024,387.51**	**$ 898,648.64**	**$ 699,683.43**	**$ 5,662,464.06**
Total Peak Commodity	**$ 10,821,557.83**	**$ 16,646,897.69**	**$ 23,423,344.12**	**$ 16,064,678.50**	**$ 11,804,608.35**	**$ 6,760,555.78**	**$ 85,521,642.27**
Off-Peak Commodity	-	-	-	-	-	-	-
Total Commodity	**$ 10,821,557.83**	**$ 16,646,897.69**	**$ 23,423,344.12**	**$ 16,064,678.50**	**$ 11,804,608.35**	**$ 6,760,555.78**	**$ 85,521,642.27**
Firm Sendout Costs	**$ 11,760,787.79**	**$ 17,781,341.89**	**$ 24,389,414.44**	**$ 17,089,066.01**	**$ 12,703,256.99**	**$ 7,460,239.21**	**$ 91,184,106.33**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

	FOR THE MONTH OF:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
1	**DEMAND**							
2	**Supply**							
3	ALBERTA NORTHEAST							
4	Northeast Gas Markets/BP							
5	**Subtotal Canadian Supply**	$ 32,410.35	$ 16,013.12	$ (36,695.40)	$ 21,776.92	$ (29,889.50)	$ 5,888.26	$ 9,503.75
6								
7	**Peaking Suppy**							
8	Granite Ridge							
9	Cheveron							
10	VPEM Demand Charges							
11	**Subtotal Peaking Supply**	$ 21,286.22	$ 20,724.59	$ 60,724.59	$ 60,654.47	$ 61,329.09	$ 24,287.59	$ 249,006.55
12								
13	**Transport Capacity**							
14	Iroquois 470-01-RTS	$ 24,828.20	$ 24,303.72	$ 23,331.41	$ 23,850.76	$ 26,702.77	$ 21,271.21	$ 144,288.07
15	National Fuel N02358	18,721.88	18,721.89	18,379.04	18,390.97	49,475.17	18,348.80	142,037.75
16	PNGTS FT-1999-001	21,924.93	21,921.36	23,171.37	21,921.36	21,921.36	21,921.36	132,781.74
17	TGP 632 FTA	68,168.50	82,112.49	89,910.85	71,298.45	80,510.41	69,361.36	461,362.06
18	TGP 2302 FTA Zone 5-6	14,006.13	14,006.13	14,006.13	13,483.55	13,715.26	13,670.89	82,888.09
19	TGP 8587 FTA	322,003.34	327,527.36	321,402.34	321,473.72	319,102.23	321,334.93	1,932,843.92
20	TGP 11234 FTA	35,944.90	46,901.94	47,875.80	47,044.04	46,311.03	40,547.65	264,625.36
21	TGP 33371 NET	38,652.23	38,641.62	37,941.36	37,941.36	37,867.09	37,771.60	228,815.26
22	TGP 42076 FTA	57,524.64	57,524.64	56,729.72	56,459.72	55,570.36	56,516.60	340,325.68
23	**Subtotal Transport Capacity**	$ 601,774.75	$ 631,661.15	$ 632,748.02	$ 611,863.93	$ 651,175.68	$ 600,744.40	$ 3,729,967.93
24								
25	**Storage Fixed**							
26	Dominion 300076-Storage	$ 2,963.80	$ 2,966.78	$ 2,912.86	$ 2,909.97	$ 2,928.39	$ 2,901.49	$ 17,583.29
27	NFG Deliverability FSS 2357	38,471.84	38,471.84	37,766.32	37,794.63	42,123.41	37,708.69	232,336.73
28	Tenn Reservation FSMA 523	49,305.95	49,305.97	44,024.46	47,502.58	52,871.41	49,445.11	292,455.48
29	HONEOYE STORAGE SS-NY	-	8,474.39	272.12	17,486.66	8,744.39	8,744.39	43,721.95
30	**Subtotal Storage**	$ 90,741.59	$ 99,218.98	$ 84,975.76	$ 105,693.84	$ 106,667.60	$ 98,799.68	$ 586,097.45
31								
32	**LNG / DISTRIGAS FLS 164**							
33	**LNG/ DISTRIGAS FLS160**							
34	**Transgas Trucking**							
35	**Subtotal Distrigas**	$ 197,500.00	$ 343,925.74	$ 270,712.87	$ 270,712.87	$ 270,712.87	$ -	$ 1,353,564.35
36								
37	**Propane**							
38	En Propane	$ -	$ -	$ 39.70	$ 3.97	$ 15.97	$ 11.91	71.55
39								
40	Intercontinental Exchange	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	3,000.00
41								
42	**Capacity Managed - Canadian**							
43								
44	**PNGTS Refund per RP02-13**							
45								
46	**Demand Subtotal**	$ 939,229.96	$ 1,102,501.62	$ 933,709.75	$ 992,026.94	$ 866,371.67	$ 649,751.86	$ 5,483,591.80
47								
48	**Capacity Release Adjustment**							
49	ALBERTA NORTHEAST							
50	TGP - FT-A 632							
51	TGP - FT-A 11234							
52	TGP - FT-A 42076							
53	PNGTS - FT							
54								
55								
56	**TOTAL DEMAND**	$ 939,229.96	$ 1,134,444.20	$ 966,070.32	$ 1,024,387.51	$ 898,648.64	$ 699,683.43	$ 5,662,464.06

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009

DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

57	**FOR THE MONTH OF:**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**Total**
58								
59	**COMMODITY**							
60								
61	**Canadian Supply**							
62	BP							
63	Nexen							
64	Sempra							
65	**Subtotal Canadian Commodity**							
66								
67	**Pipeline Transport**							
68	ANE Union/Dawn							
69	Dominion							
70	El Paso							
71	Iroquois							
72	**National Fuel**							
73	PNGTS							
74	HONEOYE							
75	**Subtotal Transp Commodity**							
76								
77	**City Gate Delivery**							
78	DISTRIGAS							
79	VPEM							
80	**Subtotal Citygate Delivery**							
81								
82	**PNGTS Supply**							
83	Dte Energy							
84	Emera							
85	Conoco							
86	**Subtotal PNGTS**							
87								
88	**Gas Supply**							
89	Andarko							
90	Chevron							
91	Colonial Energy							
92	Cokinos							
93	Conoco							
94	Emera							
95	Enjet							
96	ETC							
97	FPL Energy							
98	Hess							
99	L. Dreyfus							
100	Macquarie							
101	Nextera							
102	NJ Energy							
103	Shell US							
104	Spark Energy							
105	Tenaska							
106	Total Gas & Power							
107	Adjustments							
108	**Total Other TGP Supply**							
109								
110	**Peaking Supply**							
111	Granite Ridge (formerly AES)							
112								
113	NYMEX Hedging - Settlement							
114								
115	**STORAGE WITHDRAWALS**							
116								
117	**STORAGE INJECTIONS**							
118								
119	DISTRIGAS (FCS 064)							
120	LNG VAPOR							
121	LNG BOIL OFF							
122	**Subtotal LNG**							
123								
124	**PROPANE**							
125	Propane Storage Withdrawal							
126	Energy North Propane							
127	**Subtotal Propane**							
128								
129	Broker Cashout							
130	Other Taxes W. Virginia							
131	**Subtotal Cashouts**							
132								
133	Capacity Managed - Canadian							
134	Broker Inventory							
135	**Subtotal Capacity Managed**							
136								
137	**TOTAL COMMODITY**							
138								
139	Off System Gas Sales Cost							
140	NON-FIRM COST							
141								
142	**NET COMMODITY COST**	**$ 10,821,557.83**	**$ 16,646,897.69**	**$ 23,423,344.12**	**$ 16,064,678.50**	**$ 11,804,608.35**	**$ 6,760,555.78**	**$ 85,521,642.27**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

			Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
142	**FOR THE MONTH OF:**		**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**Total**
143									
144	Peak Demand 175.20		$ 939,229.96	$ 1,134,444.20	$ 966,070.32	$ 1,024,387.51	$ 898,648.64	$ 699,683.43	$ 5,662,464.06
145	Peak Commodity 175.20		10,821,557.83	16,646,897.69	23,423,344.12	16,064,678.50	11,804,608.35	6,760,555.78	85,521,642.27
146	Total Peak Gas Costs		**$ 11,760,787.79**	**$ 17,781,341.89**	**$ 24,389,414.44**	**$ 17,089,066.01**	**$ 12,703,256.99**	**$ 7,460,239.21**	**$ 91,184,106.33**
147									
148	Off-Peak Demand 175.40	OP	-	-	-	-	-	-	-
149	Off-Peak Comm 175.40	OP	-	-	-	-	-	-	-
150	Total Off-Peak Gas Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
151									
152	Firm Sendout Costs		**$ 11,760,787.79**	**$ 17,781,341.89**	**$ 24,389,414.44**	**$ 17,089,066.01**	**$ 12,703,256.99**	**$ 7,460,239.21**	**$ 91,184,106.33**

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	Nov-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Total	Total
		OffPeak	Peak						Peak	Peak	OffPeak
1	**VOLUMES**										
2	**RESIDENTIAL**										
3	R-1	49,257	26,393	105,870	130,363	116,004	104,556	90,897	46,522	**620,605**	**49,257**
4	R-1 FPO	4,599	2,669	11,672	15,126	12,567	10,736	8,600	4,420	**65,790**	**4,599**
5	R-3	1,859,031	1,415,528	5,808,188	8,041,478	7,753,992	6,221,174	4,058,461	1,284,234	**34,583,055**	**1,859,031**
6	R-3 FPO	406,685	351,677	1,413,973	1,940,025	1,860,243	1,494,842	976,095	309,314	**8,346,169**	**406,685**
7	R-4	11,634	2,308	230,171	680,323	876,162	599,883	671,343	250,556	**3,310,746**	**11,634**
8	R-4 FPO	1,265	1,043	42,031	211,644	231,778	153,311	153,455	52,974	**846,236**	**1,265**
9	Total Residential	2,332,471	1,799,618	7,611,905	11,018,959	10,850,746	8,584,502	5,958,851	1,948,020		
10	**COMMERCIAL/INDUSTRIAL**										
11	G41 - G43	1,445,700	939,620	4,858,798	6,617,536	6,890,482	5,387,132	3,412,529	1,109,583	**29,215,680**	**1,445,700**
12	G41 - G43 (FPO)	115,286	104,254	523,022	726,496	741,545	586,298	385,953	138,403	**3,205,971**	**115,286**
13	Total G41- G43	1,560,986	1,043,874	5,381,820	7,344,032	7,632,027	5,973,430	3,798,482	1,247,986		
14	G51 - G63	383,089	218,757	816,595	1,008,750	981,800	848,414	642,966	342,149	**4,859,431**	**383,089**
15	G51 - G63 (FPO)	26,207	23,963	99,675	123,803	109,260	99,139	79,766	41,563	**577,169**	**26,207**
16	Total G51-G63	409,296	242,720	916,270	1,132,553	1,091,060	947,553	722,732	383,712		
17	Total Sales Volumes	4,302,753	3,086,212	13,909,995	19,495,544	19,573,833	15,505,485	10,480,065	3,579,718	**85,630,852**	**4,302,753**
18	**TRANSPORTATION**										
19	G41 - G43	944,631	359,437	2,086,502	3,164,691	3,287,068	2,889,167	2,083,862	1,032,781	**14,903,508**	**944,631**
20	G51 - G63	2,421,603	72,371	2,602,769	2,658,168	2,014,101	1,830,481	2,439,024	2,015,268	**13,632,182**	**2,421,603**
21	Total Transportation Volumes	3,366,234	431,808	4,689,271	5,822,859	5,301,169	4,719,648	4,522,886	3,048,049	**28,535,690**	**3,366,234**
22	**Total Volumes**	**7,668,987**	**3,518,020**	**18,599,266**	**25,318,403**	**24,875,002**	**20,225,133**	**15,002,951**	**6,627,767**	**114,166,542**	**7,668,987**
23											
24	**RATES**										
25	Residential	1.14430	1.17470	1.15450	1.12120	1.10280	1.06770	1.00140	0.93800		
26	Residential (FPO)	1.14430	1.2745	1.27450	1.27450	1.27450	1.27450	1.27450	1.27450		
27	C/I Sales G41 to G43	1.14470	1.17490	1.15680	1.12200	1.10390	1.07040	1.00680	0.93810		
28	C/I Sales G41 to G43 (FPO)	1.14470	1.2746	1.27460	1.27460	1.27460	1.27460	1.27460	1.27460		
29	C/I Transport G41 to G43	0.00000	-0.0001	-0.00010	-0.00010	-0.00010	-0.00010	-0.00010	-0.00010		
30	C/I Sales G51 to G63	1.14410	1.17360	1.14530	1.12080	1.10220	1.06750	1.00100	0.93710		
31	C/I Sales G51 to G63 (FPO)	1.14410	1.2740	1.27400	1.27400	1.27400	1.27400	1.27400	1.27400		
32	C/I Transport G51 to G63	0.00000	-0.0001	-0.00010	-0.00010	-0.00010	-0.00010	-0.00010	-0.00010		
33											
34	**REVENUES**										
35	Residential	$ 2,196,967	$ 1,696,536	$ 7,093,512	$ 9,925,046	$ 9,645,263	$ 7,394,477	$ 4,827,450	$ 1,483,271	**$ 42,065,555**	**$ 2,196,967**
36	Residential (FPO)	$ 472,080	$ 452,943	$ 1,870,553	$ 2,761,580	$ 2,682,297	$ 2,114,254	$ 1,450,572	$ 467,369	**$ 11,799,570**	**$ 472,080**
37	C/I Sales G41 to G43	$ 1,654,893	$ 1,103,960	$ 5,620,658	$ 7,424,875	$ 7,606,403	$ 5,766,386	$ 3,435,734	$ 1,040,900	**$ 31,998,916**	**$ 1,654,893**
38	C/I Sales G41 to G43 (FPO)	$ 131,968	$ 132,882	$ 666,644	$ 925,992	$ 945,173	$ 747,295	$ 491,936	$ 176,408	**$ 4,086,331**	**$ 131,968**
39	C/I Transport G41 to G43	$ -	$ (36)	$ (209)	$ (316)	$ (329)	$ (289)	$ (208)	$ (103)	**$ (1,490)**	**$ -**
40	C/I Sales G51 to G63	$ 438,292	$ 256,733	$ 935,246	$ 1,130,607	$ 1,082,140	$ 905,682	$ 643,609	$ 320,628	**$ 5,274,645**	**$ 438,292**
41	C/I Sales G51 to G63 (FPO)	$ 29,983	$ 30,529	$ 126,986	$ 157,725	$ 139,197	$ 126,303	$ 101,622	$ 52,951	**$ 735,313**	**$ 29,983**
42	C/I Transport G51 to G63	$ -	$ (7)	$ (260)	$ (266)	$ (201)	$ (183)	$ (244)	$ (202)	**$ (1,363)**	**$ -**
43	**Winter Gas Cost Rev filed**	**$ 4,924,183**	**$ 3,673,540**	**$ 16,313,130**	**$ 22,325,243**	**$ 22,099,944**	**$ 17,053,926**	**$ 10,950,471**	**$ 3,541,223**	**$ 95,957,476**	**$ 4,924,183**
44											
45	Winter Proration	$ -	$ 18,495	$ 1,124	$ (2,146)	$ 6,402	$ 10,870	$ 30,725	$ -	**65,470**	**-**
46											
47	Less Occupant Billing	$ -	$ 6,256	$ 6,724	$ 1,403	$ 3,405	$ 9,769	$ 718	$ -	**28,276**	**-**
48	Total	$ 4,924,183	$ 3,685,779	$ 16,307,530	$ 22,321,694	$ 22,102,941	$ 17,055,026	$ 10,980,478	$ 3,541,223	$ 95,994,670	$ 4,924,183
49											
50	**Summer Gas Cost Billed (Acct 175.40)**	**$ 4,924,183**									**$ 4,924,183**
51											
52	Winter Gas Costs Billed (Acct 175.20)		**$ 3,685,822**	**$ 16,307,999**	**$ 22,322,276**	**$ 22,103,471**	**$ 17,055,498**	**$ 10,980,930**	**$ 3,541,527**	**$ 95,997,524**	
53	Winter Transportation Gas Costs Billed (Acct 175.20)	**-**	**(43)**	**(469)**	**(582)**	**(530)**	**(472)**	**(452)**	**(305)**	**$ (2,854)**	**$ -**
54	**Total Winter Gas Cost Billed (Acct 175.20)**	**$ -**	**$ 3,685,779**	**$ 16,307,530**	**$ 22,321,694**	**$ 22,102,941**	**$ 17,055,026**	**$ 10,980,478**	**$ 3,541,223**	**$ 95,994,670**	**$ 4,924,183**
55											
56				**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
57	Total Sales CGA Billed	**$ 4,924,183**	**$ 3,685,779**	**$ 16,307,530**	**$ 22,321,694**	**$ 22,102,941**	**$ 17,055,026**	**$ 10,980,478**	**$ 3,541,223**	**$ 95,994,670**	**$ 4,924,183**
58											
59	Plus: Working Capital Gas Cost Billed	29,689	12,345	55,640	77,982	78,295	62,022	41,920	14,319	**342,523**	**29,689**
60	Plus: Bad Debt Cost Billed	81,752	15,431	69,550	97,478	97,869	77,527	52,400	17,899	**428,154**	**81,752**
61	Plus: Broker Revenues	-	38,654.87	53,914.18	65,670.74	37,926.78	33,585.32	38,456.74	-	**268,209**	**-**
62											
63	**Total Winter Gas Costs Billed**	**$ 5,035,624**	**$ 3,752,209**	**$ 16,486,634**	**$ 22,562,825**	**$ 22,317,032**	**$ 17,228,161**	**$ 11,113,255**	**$ 3,573,440**	**$ 97,033,556**	**$ 5,035,624**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**Total**
1	INTERRUPTIBLE							
2								
3	280 DAY							
4								
5	OFF SYSTEM GAS SALES MARGIN							
6	PROPANE OFF SYSTEM SALES MARGIN							
7								
8	CAPACITY RELEASE CREDIT							
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	**$ (547)**	**$ (49,711)**	**$ (32,361)**	**$ (36,191)**	**$ (32,381)**	**$ (56,004)**	**$ (207,195)**

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2008 THROUGH APRIL 2009
PEAK PERIOD WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	Nov-08 30	Dec-08 31	Jan-09 31	Feb-09 28	Mar-09 31	Apr-09 30	May-09	Total
1	BEGINNING BALANCE	$ (305,497)	$ (242,889)	$ (184,815)	$ (106,095)	$ (74,624)	$ (55,098)	$ (49,400)	**$ (305,497)**
2									
3	Add: COST ALLOW	75,854	114,369	157,103	109,991	81,727	47,757		**586,801**
4									
5	Less: CUSTOMER BILLINGS	(12,345)	(55,640)	(77,982)	(78,295)	(62,022)	(41,920)	(14,319)	**(342,523)**
6									-
7	Adjustment	-	-	-	-	-	-	-	-
8									
9	ENDING BALANCE PRE INTEREST	**(241,989)**	**(184,160)**	**(105,694)**	**(74,399)**	**(54,919)**	**(49,261)**	**(63,719)**	**(61,220)**
10									
11	MONTH'S AVERAGE BALANCE	(273,743)	(213,524)	(145,254)	(90,247)	(64,771)	(52,179)		
12									
13	INTEREST RATE	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%		
14	INTEREST APPLIED	(900)	(655)	(401)	(225)	(179)	(139)		**(2,499)**
15	ENDING BALANCE	**$ (242,889)**	**$ (184,815)**	**$ (106,095)**	**$ (74,624)**	**$ (55,098)**	**$ (49,400)**	**$ (63,719)**	**$ (63,719)**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2008 THROUGH APRIL 2009
OFF PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF:	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Total**
	DAYS IN MONTH	30	31	31	28	31	30		
1	BEGINNING BALANCE	$ (38,418)	$ (68,282)	$ (68,491)	$ (68,680)	$ (68,851)	$ (69,041)	$ (69,225)	**(38,418)**
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		**$ -**
4		-							**0**
5	Less: CUSTOMER BILLINGS	(29,689)							**(29,689)**
6									
7	ENDING BALANCE PRE INTEREST	**(68,107)**	**(68,282)**	**(68,491)**	**(68,680)**	**(68,851)**	**(69,041)**	**(69,225)**	**(68,107)**
8									
9	MONTH'S AVERAGE BALANCE	(53,263)	(68,282)	(68,491)	(68,680)	(68,851)	(69,041)		
10									
11	INTEREST RATE	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%		
12	INTEREST APPLIED	(175)	(209)	(189)	(171)	(190)	(184)		**(1,118)**
13	ENDING BALANCE	**$ (68,282)**	**$ (68,491)**	**$ (68,680)**	**$ (68,851)**	**$ (69,041)**	**$ (69,225)**	**$ (69,225)**	**$ (69,225)**

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2008 THROUGH APRIL 2009
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
1	Demand	$ 938,683	$ 1,084,733	$ 933,710	$ 988,196	$ 866,268	$ 643,679	5,455,269
2	Commodity	10,821,558	16,646,898	23,423,344	16,064,679	11,804,608	6,760,556	85,521,642
3	Total Gas Costs	$ 11,760,241	$ 17,731,631	$ 24,357,054	$ 17,052,875	$ 12,670,876	$ 7,404,235	$ 90,976,912
4								
5	Working Capital Rate 1/	0.00645	0.00645	0.00645	0.00645	0.00645	0.00645	
6								
7	Total Working Capital Costs	$ 75,854	$ 114,369	$ 157,103	$ 109,991	$ 81,727	$ 47,757	$ 586,801
8								
9	Prior Period Undercollection	480,554	480,554	480,554	480,554	480,554	480,554	2,883,321
10								
11	Subtotal Gas Costs, Working Capital & Under Collection	12,316,648	18,326,554	24,994,710	17,643,419	13,233,157	7,932,546	94,447,034
12								
13	Bad Debt Rate 1/	0.0175	0.0175	0.0175	0.0175	0.0175	0.0175	
14								
15	Total Bad Debt Cost	$ 215,541	$ 320,715	$ 437,407	$ 308,760	$ 231,580	$ 138,820	$ 1,652,823

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2008 THROUGH APRIL 2009
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Total
1	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Total Gas Costs**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4								
5	Working Capital Rate	0.00645	0.00645	0.00645	0.00645	0.00645	0.00645	
6								
7	**Total Working Capital Costs**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8								
9	Prior Period Undercollection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10								
11	Subtotal Gas Costs, Working Capital & Under Collection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12								
13	Bad Debt Rate	0.0175	0.0175	0.0175	0.0175	0.0175	0.0175	
14								
15	**Total Bad Debt Cost**	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
SCHEDULE 7
WORKING CAPITAL & BAD DEBT COLLECTED

	FOR MONTH OF:	OffPeak Nov-08	Peak Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	Peak May-09	Total Peak
1	**VOLUMES**									
2	**RESIDENTIAL**									
3	R-1, R-3 and R-4	1,919,922	1,444,229	6,144,229	8,852,164	8,746,158	6,925,613	4,820,701	1,581,312	**38,514,406**
4	R-1, R-3 and R-4 (FPO)	412,549	355,389	1,467,676	2,166,795	2,104,588	1,658,889	1,138,150	366,708	**9,258,195**
5										
6	**COMMERCIAL/INDUSTRIAL**									
7	G41 - G43	1,445,700	939,620	4,858,798	6,617,536	6,890,482	5,387,132	3,412,529	1,109,583	**29,215,680**
8	G41 - G43 (FPO)	115,286	104,254	523,022	726,496	741,545	586,298	385,953	138,403	**3,205,971**
9	G51 - G63	383,089	218,757	816,595	1,008,750	981,800	848,414	642,966	342,149	**4,859,431**
10	G51 - G63 (FPO)	26,207	23,963	99,675	123,803	109,260	99,139	79,766	41,563	**577,169**
11										
12	**TRANSPORTATION**									
13	G41 - G43	944,631	359,437	2,086,502	3,164,691	3,287,068	2,889,167	2,083,862	1,032,781	**14,903,508**
14	G51 - G63	2,421,603	72,371	2,602,769	2,658,168	2,014,101	1,830,481	2,439,024	2,015,268	**13,632,182**
15										
16	**TOTAL VOLUME**	**7,668,987**	**3,518,020**	**18,599,266**	**25,318,403**	**24,875,002**	**20,225,133**	**15,002,951**	**6,627,767**	**114,166,542**
17										
18	**WORKING CAPITAL RATES**									
19	Residential R1, R3 & R4	$0.0069	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	
20	Residential R1, R-3 & R4 (FPO)	$0.0069	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	
21	C/I Sales G41 to G43	$0.0069	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	
22	C/I Sales G41 to G43 (FPO)	$0.0069	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	
23	C/I Sales G51 to G63	$0.0069	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	
24	C/I Sales G51 to G63 (FPO)	$0.0069	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040	
25										
26	**WORKING CAPITAL COSTS COLLECTED**									
27	Residential	$ 13,247	$ 5,777	$ 24,577	$ 35,409	$ 34,985	$ 27,702	$ 19,283	$ 6,325	**$ 154,058**
28	Residential (FPO)	2,847	1,422	5,871	8,667	8,418	6,636	4,553	1,467	**37,033**
29	C/I Sales G41 to G43	9,975	3,758	19,435	26,470	27,562	21,549	13,650	4,438	**116,863**
30	C/I Sales G41 to G43 (FPO)	795	417	2,092	2,906	2,966	2,345	1,544	554	**12,824**
31	C/I Sales G51 to G63	2,643	875	3,266	4,035	3,927	3,394	2,572	1,369	**19,438**
32	C/I Sales G51 to G63 (FPO)	181	96	399	495	437	397	319	166	**2,309**
33										
34	**SUMMER GAS COST WORKING CAPITAL COLLE**	**$ 29,689**	**$ 12,345**	**$ 55,640**	**$ 77,982**	**$ 78,295**	**$ 62,022**	**$ 41,920**	**$ 14,319**	**$ 342,523**
35										
36	**BAD DEBT RATES**									
37	Residential R1, R3 & R4	$0.0190	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
38	Residential R1 & R3 (FPO)	$0.0190	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
39	C/I Sales G41 to G43	$0.0190	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
40	C/I Sales G41 to G43 (FPO)	$0.0190	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
41	C/I Sales G51 to G63	$0.0190	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
42	C/I Sales G51 to G63 (FPO)	$0.0190	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	$0.0050	
43										
44	**BAD DEBTS COLLECTED**									
45	Residential R1, R3 & R4	$ 36,479	$ 7,221	$ 30,721	$ 44,261	$ 43,731	$ 34,628	$ 24,104	$ 7,907	**$ 192,572**
46	Residential R1, R-3 & R4 (FPO)	7,838	1,777	7,338.38	10,833.98	10,522.94	8,294.45	5,690.75	1,833.54	**46,291**
47	C/I Sales G41 to G43	27,468	4,698	24,293.99	33,087.68	34,452.41	26,935.66	17,062.65	5,547.92	**146,078**
48	C/I Sales G41 to G43 (FPO)	2,190	521	2,615.11	3,632.48	3,707.73	2,931.49	1,929.77	692.02	**16,030**
49	C/I Sales G51 to G63	7,279	1,094	4,082.98	5,043.75	4,909.00	4,242.07	3,214.83	1,710.75	**24,297**
50	C/I Sales G51 to G63 (FPO)	498	120	498.38	619.02	546.30	495.70	398.83	207.82	**2,886**
51										
52	**SUMMER BAD DEBTS COLLECTED**	**$ 81,752**	**$ 15,431**	**$ 69,550**	**$ 97,478**	**$ 97,869**	**$ 77,527**	**$ 52,400**	**$ 17,899**	**$ 428,154**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2008 THROUGH APRIL 2009
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

	FOR THE MONTH OF:	**Nov-08**		**Dec-08**		**Jan-09**		**Feb-09**		**Mar-09**		**Apr-09**		**Total**	
		Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	**Dollar**	**Volume Dkt**
	TENNESEE COMMODITY														
1	Gas Supply														
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TGP SUPPLY														
6															
7	PNGTS														
8	TOTAL TGP & PNGTS														
9															
10															
11															
12	**CITIGATE DELIVERY**														
13	VPEM														
14	Distrigas														
15															
16															
17	BP COMMODITY														
18	SEMPRA														
19	DTE														
20	TOTAL CANADIAN COMMODITY														
21															
22															
23	**LNG**														
24	Distrigas (FCS 064)														
25															
26	LNG Vapor														
27	LNG Injections														
28	Subtotal LNG														
29															
30															
31															
32	**Propane**														
33	Propane Withdrawal														
34	EN Propane														
35	Total Propane														
36															
37															
38	Storage Withdrawals														
39															
40															
41	Hedging Settlements														
42															
43	Cashouts														
44															
45	Capacity Managed														
46															
47	Taxes														
48															
49	Non-Firm Costs														
50															
51															
52	**NET COMMODITY COST**	**$ 10,821,558**	**1,227,014**	**$ 16,646,898**	**1,656,110**	**$ 23,423,344**	**2,302,547**	**$ 16,064,679**	**1,671,464**	**$ 11,804,608**	**1,337,775**	**$ 6,760,556**	**738,646**	**$ 85,521,642**	**8,933,556**

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ENERGY NORTH NATURAL GAS, INC

D/B/A NATIONAL GRID NH

NOVEMBER 2008 THROUGH APRIL 2009

MONTHLY PRIME RATES

SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-08	11/01 - 11/30	4.00%	30	4.0000%
Dec-08	12/01 - 012/31	3.61%	31	3.6100%
Jan-09	01/01 - 01/31	3.25%	31	3.2500%
Feb-09	02/01 - 02/28	3.25%	28	3.2500%
Mar-09	03/01 - 03/31	3.25%	31	3.2500%
Apr-09	04/01 - 04/30	3.25%	30	3.2500%

Local Distribution Adjustment Charge Calculation

			Reference
Residential Non Heating Rates - R-1			
Energy Efficiency Charge	$0.0466		Energy Efficiency Page 1
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0466	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0040	Emergency Response Incentive
Rate Case Expense Factor (RCEF)		(0.0195)	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0099	RILAP Page 1
LDAC		**$0.0410 per therm**	
Residential Heating Rates - R-3, R-4			
Energy Efficiency Charge	$0.0466		Energy Efficiency Page 1
Demand Side Management Charge	(0.0006)		Conservation Charge
Conservation Charge (CCx)		$0.0460	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0040	Emergency Response Incentive
Rate Case Expense Factor (RCEF)		(0.0195)	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0099	RILAP Page 1
LDAC		**$0.0404 per therm**	
Commercial/Industrial Low Annual Use Rates - G-41, G-51			
Energy Efficiency Charge	$0.0250		Energy Efficiency Page 1
Demand Side Management Charge	0.0000		Conservation Charge
Conservation Charge (CCx)		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0040	Emergency Response Incentive
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0099	RILAP Page 1
LDAC		**$0.0194 per therm**	
Commercial/Industrial Medium Annual Use Rates - G-42, G-52			
Energy Efficiency Charge	$0.0250		Energy Efficiency Page 1
Demand Side Management Charge	0.0000		Conservation Charge
Conservation Charge (CCx)		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0040	Emergency Response Incentive
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0099	RILAP Page 1
LDAC		**$0.0194 per therm**	
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54			
Energy Efficiency Charge	$0.0250		Energy Efficiency Page 1
Demand Side Management Charge	0.0000		Conservation Charge
Conservation Charge (CCx)		$0.0250	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0040	Emergency Response Incentive
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0099	RILAP Page 1
LDAC		**$0.0194 per therm**	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$	802,635
Temporary Rate Reconciliation		(3,740,913)
Rate Case Expense Reconciliaiton Adjustment		
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	(2,938,277)
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		92,474,643
Total Volumes		150,828,182
Rate Case Expense Factor	$	(0.0195)

EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

Customer Chg

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	4,704	4,198	4,197	4,232	4,415	4,437	2,725	46	2,890	4,428	4,266	4,508	
R-3	66,928	60,154	61,232	60,164	63,172	65,827	34,045	905	45,683	61,950	65,506	65,473	
R-4	8,067	8,370	6,126	8,560	7,069	7,215	3,381	62	3,010	4,074	285	3,214	
Total Resid.	79,699	72,722	71,555	72,956	74,657	77,479	40,151	1,014	51,583	70,452	70,057	73,195	
G-41	8,101	7,516	7,523	7,355	7,824	7,815	4,230	137	4,994	7,062	7,099	7,844	
G-42	1,556	1,433	1,453	1,421	1,529	1,534	839	25	1,000	1,431	1,427	1,561	
G-43	42	41	44	45	41	43	33	1	12	39	39	42	
G-51	1,405	1,286	1,290	1,235	1,344	1,355	738	22	887	1,258	1,234	1,346	
G-52	326	307	306	294	321	325	179	5	203	294	293	311	
G-53	38	34	34	36	32	39	35	0	11	28	33	35	
G-54	4	5	7	6	6	6	6	0	1	5	5	5	
G-63	15	15	11	14	15	13	16	0	4	15	15	14	
Total C/I	11,486	10,637	10,668	10,406	11,111	11,130	6,076	190	7,113	10,132	10,144	11,158	
Total All	91,185	83,358	82,224	83,362	85,767	88,609	46,227	1,204	58,696	80,584	80,202	84,353	

DG 08-009 Final Approved Rates- customer Charge

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
R-1	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72	$9.72
R-3	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95	$13.95
R-4	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58	$5.58
Total Resid.												
G-41	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88
G-42	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66
G-43	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59	$418.59
G-51	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88	$34.88
G-52	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66	$99.66
G-53	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56
G-54	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56
G-63	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56	$428.56
Total C/I												
Total All												

EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

DG 08-009 Temporary Rates Customer Charge

R-1	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01	$8.01
R-3	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46	$11.46
R-4	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58	$4.58
Total Resid.												
G-41	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58	$28.58
G-42	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44	$80.44
G-43	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23	$347.23
G-51	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77	$28.77
G-52	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36	$80.36
G-53	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93
G-54	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93
G-63	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93	$347.93
Total C/I												

DG 08-009 Customer Charge Variance

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	$8,044	$7,179	$7,177	$7,236	$7,550	$7,588	$4,660	$79	$4,942	$7,572	$7,295	$7,709	$77,031
R-3	$166,651	$149,783	$152,468	$149,808	$157,297	$163,909	$84,772	$2,254	$113,751	$154,257	$163,110	$163,027	$1,621,087
R-4	$8,067	$8,370	$6,126	$8,560	$7,069	$7,215	$3,381	$62	$3,010	$4,074	$285	$3,214	$59,434
Total Resid.	$182,762	$165,332	$165,771	$165,604	$171,917	$178,711	$92,813	$2,395	$121,703	$165,902	$170,690	$173,950	$1,757,551
													$0
G-41	$51,038	$47,351	$47,398	$46,334	$49,289	$49,235	$26,649	$862	$31,463	$44,493	$44,721	$49,419	$488,252
G-42	$29,901	$27,536	$27,932	$27,304	$29,379	$29,485	$16,116	$480	$19,229	$27,499	$27,423	$29,994	$292,279
G-43	$2,984	$2,906	$3,141	$3,197	$2,934	$3,047	$2,348	$86	$889	$2,763	$2,783	$2,984	$30,062
G-51	$8,584	$7,856	$7,879	$7,547	$8,209	$8,278	$4,509	$137	$5,420	$7,687	$7,540	$8,225	$81,872
G-52	$6,288	$5,924	$5,905	$5,682	$6,188	$6,265	$3,461	$92	$3,917	$5,670	$5,647	$5,994	$61,031
G-53	$3,024	$2,766	$2,766	$2,891	$2,582	$3,133	$2,854	$0	$848	$2,259	$2,629	$2,849	$28,601
G-54	$323	$403	$548	$484	$484	$500	$484	$0	$86	$403	$403	$403	$4,521
G-63	$1,242	$1,243	$887	$1,161	$1,218	$1,080	$1,259	$0	$352	$1,209	$1,243	$1,129	$12,024
Total C/I	$103,382	$95,985	$96,456	$94,600	$100,282	$101,024	$57,679	$1,657	$62,205	$91,984	$92,390	$100,998	$998,642
													$0
Total All	$286,144	$261,317	$262,227	$260,204	$272,200	$279,735	$150,493	$4,052	$183,907	$257,886	$263,080	$274,948	$2,756,193

EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

Peak Headblock Volumes

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	39,082	34,680	34,657	31,307	22,479	159	242	0	0	0	11,463	37,137	211,206
R-3	5,883,192	5,362,229	5,120,825	4,184,936	1,529,896	(67,274)	3,812	0	0	0	1,596,966	5,322,819	28,937,401
R-4	629,773	676,743	511,688	374,714	254,774	70,480	3,694	0	0	0	2,780	128,679	2,653,325
Total Resid.	6,552,047	6,073,652	5,667,170	4,590,957	1,807,149	3,365	7,748	0	0	0	1,611,209	5,488,635	31,801,932
G-41	713,816	670,245	641,003	540,261	208,093	(36,938)	478	0	0	0	174,246	633,331	3,544,535
G-42	1,486,148	1,377,183	1,383,021	1,277,661	661,985	2,645	0	0	0	0	438,572	1,430,598	8,057,813
G-43	989,872	1,237,071	1,158,135	955,018	544,125	0	0	0	0	0	21,795	808,589	5,714,605
G-51	107,905	99,642	97,558	88,391	54,040	77	(34,678)	0	0	0	30,188	98,281	541,404
G-52	304,618	285,638	285,365	265,338	172,317	0	0	0	0	0	90,742	272,681	1,676,699
G-53	892,361	1,045,453	878,929	889,711	631,421	40,554	0	0	0	0	9,577	760,897	5,148,903
G-54	824,390	335,509	385,923	462,225	328,173	0	0	0	0	0	0	767,084	3,103,304
G-63	739,255	361,259	338,291	903,507	928,779	0	482	0	0	0	374	881,240	4,153,187
Total C/I	6,058,365	5,412,000	5,168,225	5,382,112	3,528,933	6,338	(33,718)	0	0	0	765,494	5,652,701	31,940,450
Total All	12,610,412	11,485,652	10,835,395	9,973,069	5,336,082	9,703	(25,970)	0	0	0	2,376,703	11,141,336	63,742,382

DG 08-009 Final Approved Rates- Peak Headblock

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
R-1	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498
R-3	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453
R-4	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981
Total Resid.												
G-41	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956
G-42	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627
G-43	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582
G-51	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917
G-52	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496	$0.1496
G-53	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081
G-54	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353
G-63	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353
Total C/I												

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EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

DG 08-009 Temporary Rates Peak Headblock

R-1	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054
R-3	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356
R-4	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343
Total Resid.												
G-41	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732
G-42	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095
G-43	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813	$0.1813
G-51	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878
G-52	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976	$0.1976
G-53	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224	$0.1224
G-54	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911	$0.0911
G-63	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393	$0.0393
Total C/I												

DG 08-009 Peak Headblock Variance

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	($6,081)	($5,396)	($5,393)	($4,871)	($3,498)	($25)	($38)	$0	$0	$0	($1,784)	($5,779)	($32,864)
R-3	($531,252)	($484,209)	($462,410)	($377,900)	($138,150)	$6,075	($344)	$0	$0	$0	($144,206)	($480,651)	($2,613,047)
R-4	($22,798)	($24,498)	($18,523)	($13,565)	($9,223)	($2,551)	($134)	$0	$0	$0	($101)	($4,658)	($96,050)
Total Resid.	($560,131)	($514,104)	($486,326)	($396,336)	($150,870)	$3,499	($516)	$0	$0	$0	($146,090)	($491,087)	($2,741,961)
													$0
G-41	($55,392)	($52,011)	($49,742)	($41,924)	($16,148)	$2,866	($37)	$0	$0	$0	($13,521)	($49,146)	($275,056)
G-42	($69,552)	($64,452)	($64,725)	($59,795)	($30,981)	($124)	$0	$0	$0	$0	($20,525)	($66,952)	($377,106)
G-43	($22,866)	($28,576)	($26,753)	($22,061)	($12,569)	$0	$0	$0	$0	$0	($503)	($18,678)	($132,007)
G-51	($10,370)	($9,576)	($9,375)	($8,494)	($5,193)	($7)	$3,333	$0	$0	$0	($2,901)	($9,445)	($52,029)
G-52	($14,622)	($13,711)	($13,698)	($12,736)	($8,271)	$0	$0	$0	$0	$0	($4,356)	($13,089)	($80,482)
G-53	($12,761)	($14,950)	($12,569)	($12,723)	($9,029)	($580)	$0	$0	$0	$0	($137)	($10,881)	($73,629)
G-54	($46,001)	($18,721)	($21,535)	($25,792)	($18,312)	$0	$0	$0	$0	$0	$0	($42,803)	($173,164)
G-63	($2,957)	($1,445)	($1,353)	($3,614)	($3,715)	$0	($2)	$0	$0	$0	($1)	($3,525)	($16,613)
Total C/I	($234,520)	($203,442)	($199,749)	($187,139)	($104,219)	$2,155	$3,294	$0	$0	$0	($41,945)	($214,519)	($1,180,086)
													$0
Total All	($794,651)	($717,546)	($686,076)	($583,475)	($255,089)	$5,654	$2,778	$0	$0	$0	($188,036)	($705,607)	($3,922,047)

EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

Peak Tailblock Volumes

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	106,921	93,876	80,552	64,498	28,313	52	170	0	0	0	17,717	80,642	472,741
R-3	4,105,391	4,273,180	2,603,503	803,941	41,591	(27,826)	(1,129)	0	0	0	179,409	1,964,868	13,942,928
R-4	250,420	379,386	226,607	416,520	38,701	17,072	712	0	0	0	577	38,621	1,368,616
Total Resid.	4,462,732	4,746,442	2,910,662	1,284,959	108,605	(10,702)	(247)	0	0	0	197,703	2,084,131	15,784,285
G-41	3,147,080	3,286,069	2,391,766	1,269,686	344,333	(30,913)	(815)	0	0	0	304,432	1,901,969	12,613,607
G-42	4,169,263	4,398,798	3,236,869	1,878,927	592,648	(1,763)	0	0	0	0	426,353	2,548,239	17,249,334
G-43	0	0	0	0	0	0	0	0	0	0	0	0	0
G-51	391,820	416,523	335,423	240,233	119,330	5	(133)	0	0	0	76,471	311,017	1,890,689
G-52	527,897	561,188	446,338	319,305	163,090	0	0	0	0	0	81,945	376,846	2,476,609
G-53	0	0	0	0	0	0	0	0	0	0	0	0	0
G-54	0	0	0	0	0	0	0	0	0	0	0	0	0
G-63	0	0	0	0	0	0	0	0	0	0	0	0	0
Total C/I	8,236,060	8,662,578	6,410,396	3,708,151	1,219,401	(32,671)	(948)	0	0	0	889,201	5,138,071	34,230,239
Total All	12,698,792	13,409,020	9,321,058	4,993,110	1,328,006	(43,373)	(1,195)	0	0	0	1,086,904	7,222,202	50,014,524

DG 08-009 Final Approved Rates- Peak Tailblock

R-1	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498
R-3	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849
R-4	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740
Total Resid.												
G-41	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923
G-42	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735
G-43	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582	$0.1582
G-51	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238
G-52	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015	$0.1015
G-53	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081	$0.1081
G-54	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353
G-63	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353	$0.0353
Total C/I												

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EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

DG 08-009 Temporary Rates Peak Tailblock

R-1	$0.2696	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
R-3	$0.1950	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
R-4	$0.0780	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Total Resid.												
G-41	$0.2427	$0.24	$0.24	$0.24	$0.24	$0.24	$0.24	$0.24	$0.24	$0.24	$0.24	$0.24
G-42	$0.2044	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
G-43	$0.1813	$0.18	$0.18	$0.18	$0.18	$0.18	$0.18	$0.18	$0.18	$0.18	$0.18	$0.18
G-51	$0.1859	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
G-52	$0.1341	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
G-53	$0.1224	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12
G-54	$0.0911	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
G-63	$0.0393	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Total C/I												

DG 08-009 Peak Tailblock Variance

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	($12,809)	($11,246)	($9,650)	($7,727)	($3,392)	($6)	($20)	$0	$0	$0	($2,122)	($9,661)	($56,634)
R-3	($41,464)	($43,159)	($26,295)	($8,120)	($420)	$281	$11	$0	$0	$0	($1,812)	($19,845)	($140,824)
R-4	($1,002)	($1,518)	($906)	($1,666)	($155)	($68)	($3)	$0	$0	$0	($2)	($154)	($5,474)
Total Resid.	($55,275)	($55,923)	($36,852)	($17,513)	($3,967)	$207	($12)	$0	$0	$0	($3,937)	($29,661)	($202,932)
													$0
G-41	($158,613)	($165,618)	($120,545)	($63,992)	($17,354)	$1,558	$41	$0	$0	$0	($15,343)	($95,859)	($635,726)
G-42	($128,830)	($135,923)	($100,019)	($58,059)	($18,313)	$54	$0	$0	$0	$0	($13,174)	($78,741)	($533,004)
G-43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-51	($24,332)	($25,866)	($20,830)	($14,918)	($7,410)	($0)	$8	$0	$0	$0	($4,749)	($19,314)	($117,412)
G-52	($17,209)	($18,295)	($14,551)	($10,409)	($5,317)	$0	$0	$0	$0	$0	($2,671)	($12,285)	($80,737)
G-53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-54	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total C/I	($328,985)	($345,702)	($255,945)	($147,379)	($48,394)	$1,612	$49	$0	$0	$0	($35,938)	($206,199)	($1,366,879)
													$0
Total All	($384,260)	($401,625)	($292,797)	($164,892)	($52,361)	$1,819	$38	$0	$0	$0	($39,875)	($235,860)	($1,569,812)

EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

OffPeak Headblock Volumes

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	91	45	26	154	12,832	34,361	17,586	342	10,608	34,562	22,948	154	133,709
R-3	(5,895)	(6,966)	(4,018)	(4,041)	464,621	1,093,906	497,846	12,372	350,803	1,035,305	722,602	(21,726)	4,134,809
R-4	10,440	9,943	2,414	5,443	43,544	107,084	45,757	814	22,441	69,994	4,710	29,987	352,571
Total Resid.	4,636	3,022	(1,578)	1,556	520,997	1,235,351	561,189	13,528	383,852	1,139,861	750,260	8,415	4,621,089
G-41	226	17	174	(628)	41,005	86,880	33,706	749	61,579	79,934	72,282	1,554	377,478
G-42	154	843	1,211	0	187,436	389,501	174,405	3,545	70,798	386,201	323,810	5,760	1,543,662
G-43	0	0	0	0	13,739	338,859	198,132	60	20,587	305,496	536,984	41,095	1,454,952
G-51	444	(51)	0	(576)	30,242	76,205	75,019	850	15,398	70,267	50,552	477	318,827
G-52	0	0	0	0	95,840	264,183	145,908	2,859	61,796	239,514	163,012	1,559	974,671
G-53	0	0	0	0	18,106	594,340	555,068	0	24,818	580,837	700,513	43,803	2,517,485
G-54	0	0	0	0	0	542,200	594,364	0	1,770	687,041	695,007	0	2,520,382
G-63	0	0	0	0	408	781,624	858,492	0	53,235	735,030	960,543	0	3,389,332
Total C/I	824	809	1,385	(1,204)	386,776	3,073,792	2,635,094	8,063	309,981	3,084,320	3,502,703	94,248	13,096,789
Total All	5,460	3,831	(193)	352	907,773	4,309,143	3,196,283	21,591	693,833	4,224,181	4,252,963	102,663	17,717,878

DG 08-009 Final Approved Rates- OffPeak Headblock Rates

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
R-1	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498
R-3	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453	$0.2453
R-4	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981	$0.0981
Total Resid.												
G-41	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956	$0.2956
G-42	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627	$0.2627
G-43	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724
G-51	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917	$0.1917
G-52	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100	$0.1100
G-53	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517
G-54	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190
G-63	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190
Total C/I												
Total All												

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EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

DG 08-009 Temporary Rates OffPeak Headblock Rates

R-1	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054	$0.3054
R-3	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356	$0.3356
R-4	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343	$0.1343
Total Resid.												
G-41	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732	$0.3732
G-42	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095	$0.3095
G-43	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830
G-51	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878	$0.2878
G-52	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453	$0.1453
G-53	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586
G-54	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467
G-63	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214
Total C/I												

DG 08-009 OffPeak Headblock Variance

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	($14)	($7)	($4)	($24)	($1,997)	($5,347)	($2,736)	($53)	($1,651)	($5,378)	($3,571)	($24)	($20,805)
R-3	$532	$629	$363	$365	($41,955)	($98,780)	($44,955)	($1,117)	($31,678)	($93,488)	($65,251)	$1,962	($373,373)
R-4	($378)	($360)	($87)	($197)	($1,576)	($3,876)	($1,656)	($29)	($812)	($2,534)	($171)	($1,086)	($12,763)
Total Resid.	$140	$262	$271	$144	($45,528)	($108,003)	($49,348)	($1,200)	($34,140)	($101,400)	($68,992)	$852	($406,941)
													$0
G-41	($18)	($1)	($14)	$49	($3,182)	($6,742)	($2,616)	($58)	($4,779)	($6,203)	($5,609)	($121)	($29,292)
G-42	($7)	($39)	($57)	$0	($8,772)	($18,229)	($8,162)	($166)	($3,313)	($18,074)	($15,154)	($270)	($72,243)
G-43	$0	$0	$0	$0	($146)	($3,592)	($2,100)	($1)	($218)	($3,238)	($5,692)	($436)	($15,422)
G-51	($43)	$5	$0	$55	($2,906)	($7,323)	($7,209)	($82)	($1,480)	($6,753)	($4,858)	($46)	($30,639)
G-52	$0	$0	$0	$0	($3,383)	($9,326)	($5,151)	($101)	($2,181)	($8,455)	($5,754)	($55)	($34,406)
G-53	$0	$0	$0	$0	($125)	($4,101)	($3,830)	$0	($171)	($4,008)	($4,834)	($302)	($17,371)
G-54	$0	$0	$0	$0	$0	($15,019)	($16,464)	$0	($49)	($19,031)	($19,252)	$0	($69,815)
G-63	$0	$0	$0	$0	($1)	($1,876)	($2,060)	$0	($128)	($1,764)	($2,305)	$0	($8,134)
Total C/I	($67)	($36)	($70)	$104	($18,515)	($66,207)	($47,592)	($407)	($12,319)	($67,526)	($63,458)	($1,229)	($277,323)
													$0
Total All	$73	$226	$201	$248	($64,043)	($174,210)	($96,940)	($1,607)	($46,460)	($168,925)	($132,450)	($377)	($684,264)

EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

OffPeak Tailblock Volumes

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	(351)	(121)	18	84	13,570	29,357	12,078	170	26,031	26,720	30,102	(555)	137,103
R-3	(9,464)	(15,050)	(3,813)	(2,446)	492,109	602,596	175,933	4,078	500,227	724,743	1,526,805	(45,494)	3,950,224
R-4	1,019	41,414	12,494	30,376	51,803	72,686	9,761	150	36,580	42,464	8,719	74,486	381,952
Total Resid.	(8,796)	26,243	8,699	28,014	557,482	704,639	197,772	4,398	562,838	793,927	1,565,626	28,437	4,469,279
G-41	1,197	289	1,547	(1,628)	257,423	409,941	140,752	3,043	173,651	363,692	586,744	13,795	1,950,446
G-42	764	1,019	(6,613)	0	300,896	519,508	170,903	6,208	555,700	650,713	1,020,474	81,753	3,301,323
G-43	0	0	0	0	0	0	0	0	0	0	0	0	0
G-51	860	0	0	(180)	64,374	156,877	78,128	2,302	124,150	159,637	122,480	2,303	710,931
G-52	0	0	0	0	67,232	193,190	103,950	2,251	193,546	192,186	164,223	3,131	919,709
G-53	0	0	0	0	0	0	0	0	0	0	0	0	0
G-54	0	0	0	0	0	0	0	0	0	0	0	0	0
G-63	0	0	0	0	0	0	0	0	0	0	0	0	0
Total C/I	2,821	1,308	(5,066)	(1,808)	689,925	1,279,516	493,733	13,804	1,047,047	1,366,228	1,893,921	100,982	6,882,409
Total All	(5,975)	27,551	3,633	26,206	1,247,407	1,984,155	691,505	18,202	1,609,885	2,160,155	3,459,547	129,419	11,351,688

DG 08-009 Final Approved Rates- OffPeak Tailblock Rates

R-1	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498	$0.1498
R-3	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849	$0.1849
R-4	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740	$0.0740
Total Resid.												
G-41	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923	$0.1923
G-42	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735	$0.1735
G-43	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724	$0.0724
G-51	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238	$0.1238
G-52	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633	$0.0633
G-53	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517	$0.0517
G-54	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190
G-63	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190	$0.0190
Total C/I												

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EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

DG 08-009 Temporary Rates OffPeak Tailblock Rate

R-1	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696	$0.2696
R-3	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950	$0.1950
R-4	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780	$0.0780
Total Resid.												
G-41	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427	$0.2427
G-42	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044	$0.2044
G-43	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830	$0.0830
G-51	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859
G-52	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836
G-53	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586	$0.0586
G-54	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467
G-63	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214
Total C/I												

DG 08-009 OffPeak Tailblock Variance

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	$42	$14	($2)	($10)	($1,626)	($3,517)	($1,447)	($20)	($3,119)	($3,201)	($3,606)	$66	($16,425)
R-3	$96	$152	$39	$25	($4,970)	($6,086)	($1,777)	($41)	($5,052)	($7,320)	($15,421)	$459	($39,897)
R-4	($4)	($166)	($50)	($122)	($207)	($291)	($39)	($1)	($146)	($170)	($35)	($298)	($1,528)
Total Resid.	$134	$1	($14)	($107)	($6,803)	($9,894)	($3,263)	($62)	($8,317)	($10,691)	($19,062)	$228	($57,850)
													$0
G-41	($60)	($15)	($78)	$82	($12,974)	($20,661)	($7,094)	($153)	($8,752)	($18,330)	($29,572)	($695)	($98,302)
G-42	($24)	($31)	$204	$0	($9,298)	($16,053)	($5,281)	($192)	($17,171)	($20,107)	($31,533)	($2,526)	($102,011)
G-43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-51	($53)	$0	$0	$11	($3,998)	($9,742)	($4,852)	($143)	($7,710)	($9,913)	($7,606)	($143)	($44,149)
G-52	$0	$0	$0	$0	($1,365)	($3,922)	($2,110)	($46)	($3,929)	($3,901)	($3,334)	($64)	($18,670)
G-53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-54	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total C/I	($137)	($46)	$126	$93	($27,634)	($50,378)	($19,337)	($534)	($37,562)	($52,252)	($72,044)	($3,428)	($263,132)
													$0
Total All	($4)	($45)	$113	($14)	($34,437)	($60,272)	($22,600)	($596)	($45,879)	($62,943)	($91,106)	($3,200)	($320,982)

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EnergyNorth Temporary vs. Final Rate True Up in DG 08-009

Total Volume													
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	145,743	128,480	115,253	96,043	77,194	63,929	30,076	512	36,639	61,282	82,230	117,378	954,759
R-3	9,973,224	9,613,393	7,716,497	4,982,390	2,528,217	1,601,402	676,462	16,450	851,030	1,760,048	4,025,782	7,220,467	50,965,362
R-4	891,652	1,107,486	753,203	827,053	388,822	267,322	59,924	964	59,021	112,458	16,786	271,773	4,756,464
Total Resid.	11,010,619	10,849,359	8,584,953	5,905,486	2,994,233	1,932,653	766,462	17,926	946,690	1,933,788	4,124,798	7,609,618	56,676,585
G-41	3,862,319	3,956,620	3,034,490	1,807,691	850,854	428,970	174,121	3,792	235,230	443,626	1,137,704	2,550,649	18,486,066
G-42	5,656,329	5,777,843	4,614,488	3,156,588	1,742,965	909,890	345,307	9,753	626,498	1,036,913	2,209,208	4,066,350	30,152,132
G-43	989,872	1,237,071	1,158,135	955,018	557,864	338,859	198,132	60	20,587	305,496	558,779	849,684	7,169,557
G-51	501,029	516,114	432,981	327,868	267,986	233,164	118,336	3,152	139,548	229,904	279,691	412,078	3,461,851
G-52	832,515	846,826	731,703	584,643	498,479	457,373	249,858	5,110	255,342	431,700	499,922	654,217	6,047,688
G-53	892,361	1,045,453	878,929	889,711	649,527	634,894	555,068	0	24,818	580,837	710,090	804,700	7,666,388
G-54	824,390	335,509	385,923	462,225	328,173	542,200	594,364	0	1,770	687,041	695,007	767,084	5,623,686
G-63	739,255	361,259	338,291	903,507	929,187	781,624	858,974	0	53,235	735,030	960,917	881,240	7,542,519
Total C/I	14,298,070	14,076,695	11,574,940	9,087,251	5,825,035	4,326,974	3,094,160	21,867	1,357,028	4,450,547	7,051,318	10,986,002	86,149,887
													0
Total All	25,308,689	24,926,054	20,159,893	14,992,737	8,819,268	6,259,627	3,860,622	39,793	2,303,718	6,384,335	11,176,116	18,595,620	142,826,472

Total Adjustment													
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
R-1	($10,819)	($9,456)	($7,872)	($5,396)	($2,962)	($1,307)	$419	$5	$173	($1,007)	($3,788)	($7,688)	($49,698)
R-3	($405,438)	($376,804)	($335,837)	($235,822)	($28,198)	$65,399	$37,707	$1,096	$77,021	$53,449	($63,580)	($335,047)	($1,546,054)
R-4	($16,114)	($18,172)	($13,441)	($6,989)	($4,092)	$428	$1,549	$32	$2,051	$1,370	($23)	($2,982)	($56,382)
Total Resid.	($432,371)	($404,432)	($357,149)	($248,207)	($35,251)	$64,520	$39,675	$1,133	$79,245	$53,812	($67,391)	($345,717)	($1,652,134)
G-41	($163,045)	($170,294)	($122,980)	($59,452)	($370)	$26,256	$16,943	$651	$17,933	$19,960	($19,325)	($96,402)	($550,125)
G-42	($168,512)	($172,909)	($136,665)	($90,549)	($37,984)	($4,865)	$2,673	$122	($1,256)	($10,683)	($52,963)	($118,494)	($792,086)
G-43	($19,882)	($25,671)	($23,612)	($18,864)	($9,781)	($545)	$248	$85	$671	($475)	($3,412)	($16,130)	($117,367)
G-51	($26,214)	($27,581)	($22,326)	($15,799)	($11,298)	($8,795)	($4,212)	($88)	($3,769)	($8,979)	($12,574)	($20,723)	($162,357)
G-52	($25,543)	($26,081)	($22,343)	($17,464)	($12,148)	($6,983)	($3,800)	($55)	($2,193)	($6,687)	($10,468)	($19,499)	($153,264)
G-53	($9,737)	($12,184)	($9,803)	($9,831)	($6,572)	($1,548)	($976)	$0	$677	($1,749)	($2,342)	($8,334)	($62,399)
G-54	($45,678)	($18,318)	($20,986)	($25,308)	($17,828)	($14,519)	($15,980)	$0	$37	($18,628)	($18,849)	($42,400)	($238,458)
G-63	($1,715)	($202)	($466)	($2,453)	($2,499)	($795)	($803)	$0	$224	($555)	($1,063)	($2,396)	($12,723)
Total C/I	($460,327)	($453,240)	($359,182)	($239,721)	($98,480)	($11,794)	($5,906)	$716	$12,323	($27,794)	($120,996)	($324,378)	($2,088,778)
Total All	($892,698)	($857,672)	($716,331)	($487,928)	($133,731)	$52,726	$33,768	$1,849	$91,569	$26,018	($188,387)	($670,095)	($3,740,913)

DG 06-107 Merger Settlement - Emergency Response Incentive

Emergency Response Merger Incentive

Merger Incentive - Emergency Response	$	600,000
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		92,474,643
Total Volumes		150,828,182
Rate Case Expense Factor	$	0.0040

			CURRENT MONTH					CUMMULATIVE TOTALS					LEAK RESPONSE PERCENTAGE			TARGET METRICS		
Year	Month	Normal Hours / After Hours / Weekends & Holidays	0-30 Mins	31-46 Mins	46-60 Mins	Over 60 Mins	Grand Total	0-30 Mins	31-46 Mins	46-60 Mins	Over 60 Mins	Grand Total	30 Mins	45 Mins	60 Mins	30 Mins	45 Mins	60 Mins
2007	Sep	After Hours	62	6	3	1	72	62	6	3	1	72	86.11%	94.44%	98.61%	80.00%	86.00%	95.00%
		Normal Hours	121	6			127	121	6			127	95.28%	100.00%	100.00%	82.00%	90.00%	97.00%
		Weekends & Holidays	46	4			50	46	4			50	92.00%	100.00%	100.00%	76.00%	84.00%	94.00%
		Sep Total	**229**	**16**	**3**	**1**	**249**	**229**	**16**	**3**	**1**	**249**						
	Oct	After Hours	60	8	4	1	73	122	14	7	2	145	84.14%	93.79%	98.62%	80.00%	86.00%	95.00%
		Normal Hours	185	8	1	1	195	306	14	1	1	322	95.03%	99.38%	99.69%	82.00%	90.00%	97.00%
		Weekends & Holidays	37	3		1	41	83	7	0	1	91	91.21%	98.90%	98.90%	76.00%	84.00%	94.00%
		Oct Total	**282**	**19**	**5**	**3**	**309**	**511**	**35**	**8**	**4**	**558**						
	Nov	After Hours	71	4	1		76	193	18	8	2	221	87.33%	95.48%	99.10%	80.00%	86.00%	95.00%
		Normal Hours	148	11			159	454	25	1	1	481	94.39%	99.58%	99.79%	82.00%	90.00%	97.00%
		Weekends & Holidays	51	6	4		61	134	13	4	1	152	88.16%	96.71%	99.34%	76.00%	84.00%	94.00%
		Nov Total	**270**	**21**	**5**	**0**	**296**	**781**	**56**	**13**	**4**	**854**						
	Dec	After Hours	76	20	6	2	104	269	38	14	4	325	82.77%	94.46%	98.77%	80.00%	86.00%	95.00%
		Normal Hours	158	11	4		173	612	36	5	1	654	93.58%	99.08%	99.85%	82.00%	90.00%	97.00%
		Weekends & Holidays	86	9	3	4	102	220	22	7	5	254	86.61%	95.28%	98.03%	76.00%	84.00%	94.00%
		Dec Total	**320**	**40**	**13**	**6**	**379**	**1101**	**96**	**26**	**10**	**1233**						
2008	Jan	After Hours	78	4		1	83	347	42	14	5	408	85.05%	95.34%	98.77%	80.00%	86.00%	95.00%
		Normal Hours	176	7	6		189	788	43	11	1	843	93.48%	98.58%	99.88%	82.00%	90.00%	97.00%
		Weekends & Holidays	73	10	6	1	90	293	32	13	6	344	85.17%	94.48%	98.26%	76.00%	84.00%	94.00%
		Jan Total	**327**	**21**	**12**	**2**	**362**	**1428**	**117**	**38**	**12**	**1595**						
	Feb	After Hours	56	3	3	1	63	403	45	17	6	471	85.56%	95.12%	98.73%	80.00%	86.00%	95.00%
		Normal Hours	126	5	2	1	134	914	48	13	2	977	93.55%	98.46%	99.80%	82.00%	90.00%	97.00%
		Weekends & Holidays	47	4	3		54	340	36	16	6	398	85.43%	94.47%	98.49%	76.00%	84.00%	94.00%
		Feb Total	**229**	**12**	**8**	**2**	**251**	**1657**	**129**	**46**	**14**	**1846**						
	Mar	After Hours	77	7	1	2	87	480	52	18	8	558	86.02%	95.34%	98.57%	80.00%	86.00%	95.00%
		Normal Hours	150	11		1	162	1064	59	13	3	1139	93.42%	98.60%	99.74%	82.00%	90.00%	97.00%
		Weekends & Holidays	49	8	1	1	59	389	44	17	7	457	85.12%	94.75%	98.47%	76.00%	84.00%	94.00%
		Mar Total	**276**	**26**	**2**	**4**	**308**	**1933**	**155**	**48**	**18**	**2154**						
	Apr	After Hours	73	7			80	553	59	18	8	638	86.68%	95.92%	98.75%	80.00%	86.00%	95.00%
		Normal Hours	116	4	2	1	123	1180	63	15	4	1262	93.50%	98.49%	99.68%	82.00%	90.00%	97.00%
		Weekends & Holidays	39	3	1		43	428	47	18	7	500	85.60%	95.00%	98.60%	76.00%	84.00%	94.00%
		Apr Total	**228**	**14**	**3**	**1**	**246**	**2161**	**169**	**51**	**19**	**2400**						
	May	After Hours	45	4			49	598	63	18	8	687	87.05%	96.22%	98.84%	80.00%	86.00%	95.00%
		Normal Hours	108	6	1	1	116	1288	69	16	5	1378	93.47%	98.48%	99.64%	82.00%	90.00%	97.00%
		Weekends & Holidays	24	5			29	452	52	18	7	529	85.44%	95.27%	98.68%	76.00%	84.00%	94.00%
		May Total	**177**	**15**	**1**	**1**	**194**	**2338**	**184**	**52**	**20**	**2594**						
	Jun	After Hours	36	4	2		42	634	67	20	8	729	86.97%	96.16%	98.90%	80.00%	86.00%	95.00%
		Normal Hours	77	13	1		91	1365	82	17	5	1469	92.92%	98.50%	99.66%	82.00%	90.00%	97.00%
		Weekends & Holidays	23	3			26	475	55	18	7	555	85.59%	95.50%	98.74%	76.00%	84.00%	94.00%
		Jun Total	**136**	**20**	**3**	**0**	**159**	**2474**	**204**	**55**	**20**	**2753**						
	Jul	After Hours	35	6	1		42	669	73	21	8	771	86.77%	96.24%	98.96%	80.00%	86.00%	95.00%
		Normal Hours	83	7			90	1448	89	17	5	1559	92.88%	98.59%	99.68%	82.00%	90.00%	97.00%
		Weekends & Holidays	14	1			15	489	56	18	7	570	85.79%	95.61%	98.77%	76.00%	84.00%	94.00%
		Jul Total	**132**	**14**	**1**	**0**	**147**	**2606**	**218**	**56**	**20**	**2900**						
	Aug	After Hours	47	9	1		57	716	82	22	8	828	86.47%	96.38%	99.03%	80.00%	86.00%	95.00%
		Normal Hours	112	5			117	1560	94	17	5	1676	93.08%	98.69%	99.70%	82.00%	90.00%	97.00%
		Weekends & Holidays	27	2			29	516	58	18	7	599	86.14%	95.83%	98.83%	76.00%	84.00%	94.00%
		Aug Total	**186**	**16**	**1**	**0**	**203**	**2792**	**234**	**57**	**20**	**3103**						

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Schedule 19
Emergency Response Incentive

			CURRENT MONTH					CUMMULATIVE TOTALS					LEAK RESPONSE PERCENTAGE			TARGET METRICS		
Year	Month	Normal Hours / After Hours / Weekends & Holidays	0-30 Mins	31-46 Mins	46-60 Mins	Over 60 Mins	Grand Total	0-30 Mins	31-46 Mins	46-60 Mins	Over 60 Mins	Grand Total	30 Mins	45 Mins	60 Mins	30 Mins	45 Mins	60 Mins
2008	Jan	After Hours	78	4		1	83	78	4	0	1	83	93.98%	98.80%	98.80%	80.00%	86.00%	95.00%
		Normal Hours	176	7	6		189	176	7	6	0	189	93.12%	96.83%	100.00%	82.00%	90.00%	97.00%
		Weekends & Holidays	73	10	6	1	90	73	10	6	1	90	81.11%	92.22%	98.89%	76.00%	84.00%	94.00%
		Jan Total	**327**	**21**	**12**	**2**	**362**	**327**	**21**	**12**	**2**	**362**						
	Feb	After Hours	56	3	3	1	63	134	7	3	2	146	91.78%	96.58%	98.63%	80.00%	86.00%	95.00%
		Normal Hours	126	5	2	1	134	302	12	8	1	323	93.50%	97.21%	99.69%	82.00%	90.00%	97.00%
		Weekends & Holidays	47	4	3		54	120	14	9	1	144	83.33%	93.06%	99.31%	76.00%	84.00%	94.00%
		Feb Total	**229**	**12**	**8**	**2**	**251**	**556**	**33**	**20**	**4**	**613**						
	Mar	After Hours	77	7	1	2	87	211	14	4	4	233	90.56%	96.57%	98.28%	80.00%	86.00%	95.00%
		Normal Hours	150	11		1	162	452	23	8	2	485	93.20%	97.94%	99.59%	82.00%	90.00%	97.00%
		Weekends & Holidays	49	8	1	1	59	169	22	10	2	203	83.25%	94.09%	99.01%	76.00%	84.00%	94.00%
		Mar Total	**276**	**26**	**2**	**4**	**308**	**832**	**59**	**22**	**8**	**921**						
	Apr	After Hours	73	7			80	284	21	4	4	313	90.73%	97.44%	98.72%	80.00%	86.00%	95.00%
		Normal Hours	116	4	2	1	123	568	27	10	3	608	93.42%	97.86%	99.51%	82.00%	90.00%	97.00%
		Weekends & Holidays	39	3	1		43	208	25	11	2	246	84.55%	94.72%	99.19%	76.00%	84.00%	94.00%
		Apr Total	**228**	**14**	**3**	**1**	**246**	**1060**	**73**	**25**	**9**	**1167**						
	May	After Hours	45	4			49	329	25	4	4	362	90.88%	97.79%	98.90%	80.00%	86.00%	95.00%
		Normal Hours	108	6	1	1	116	676	33	11	4	724	93.37%	97.93%	99.45%	82.00%	90.00%	97.00%
		Weekends & Holidays	24	5			29	232	30	11	2	275	84.36%	95.27%	99.27%	76.00%	84.00%	94.00%
		May Total	**177**	**15**	**1**	**1**	**194**	**1237**	**88**	**26**	**10**	**1361**						
	Jun	After Hours	36	4	2		42	365	29	6	4	404	90.35%	97.52%	99.01%	80.00%	86.00%	95.00%
		Normal Hours	77	13	1		91	753	46	12	4	815	92.39%	98.04%	99.51%	82.00%	90.00%	97.00%
		Weekends & Holidays	23	3			26	255	33	11	2	301	84.72%	95.68%	99.34%	76.00%	84.00%	94.00%
		Jun Total	**136**	**20**	**3**	**0**	**159**	**1373**	**108**	**29**	**10**	**1520**						
	Jul	After Hours	35	6	1		42	400	35	7	4	446	89.69%	97.53%	99.10%	80.00%	86.00%	95.00%
		Normal Hours	83	7			90	836	53	12	4	905	92.38%	98.23%	99.56%	82.00%	90.00%	97.00%
		Weekends & Holidays	14	1			15	269	34	11	2	316	85.13%	95.89%	99.37%	76.00%	84.00%	94.00%
		Jul Total	**132**	**14**	**1**	**0**	**147**	**1505**	**122**	**30**	**10**	**1667**						
	Aug	After Hours	47	9	1		57	447	44	8	4	503	88.87%	97.61%	99.20%	80.00%	86.00%	95.00%
		Normal Hours	112	5			117	948	58	12	4	1022	92.76%	98.43%	99.61%	82.00%	90.00%	97.00%
		Weekends & Holidays	27	2			29	296	36	11	2	345	85.80%	96.23%	99.42%	76.00%	84.00%	94.00%
		Aug Total	**186**	**16**	**1**	**0**	**203**	**1691**	**138**	**31**	**10**	**1870**						
	Sep	After Hours	52	6	1	1	60	499	50	9	5	563	88.63%	97.51%	99.11%	80.00%	86.00%	95.00%
		Normal Hours	127	11	1		139	1075	69	13	4	1161	92.59%	98.54%	99.66%	82.00%	90.00%	97.00%
		Weekends & Holidays	34	6	3		43	330	42	14	2	388	85.05%	95.88%	99.48%	76.00%	84.00%	94.00%
		Sep Total	**213**	**23**	**5**	**1**	**242**	**1904**	**161**	**36**	**11**	**2112**						
	Oct	After Hours	68	6			74	567	56	9	5	637	89.01%	97.80%	99.22%	80.00%	86.00%	95.00%
		Normal Hours	156	16	5	1	178	1231	85	18	5	1339	91.93%	98.28%	99.63%	82.00%	90.00%	97.00%
		Weekends & Holidays	37	3			40	367	45	14	2	428	85.75%	96.26%	99.53%	76.00%	84.00%	94.00%
		Oct Total	**261**	**25**	**5**	**1**	**292**	**2165**	**186**	**41**	**12**	**2404**						
	Nov	After Hours	45	9	1		55	612	65	10	5	692	88.44%	97.83%	99.28%	80.00%	86.00%	95.00%
		Normal Hours	111	7	1		119	1342	92	19	5	1458	92.04%	98.35%	99.66%	82.00%	90.00%	97.00%
		Weekends & Holidays	53	7	2		62	420	52	16	2	490	85.71%	96.33%	99.59%	76.00%	84.00%	94.00%
		Nov Total	**209**	**23**	**4**	**0**	**236**	**2374**	**209**	**45**	**12**	**2640**						
	Dec	After Hours	73	15	3	2	93	**685**	**80**	**13**	**7**	**785**	**87.26%**	**97.45%**	**99.11%**	80.00%	86.00%	95.00%
		Normal Hours	140	16			156	**1482**	**108**	**19**	**5**	**1614**	**91.82%**	**98.51%**	**99.69%**	82.00%	90.00%	97.00%
		Weekends & Holidays	69	13	4	1	87	**489**	**65**	**20**	**3**	**577**	**84.75%**	**96.01%**	**99.48%**	76.00%	84.00%	94.00%
		Dec Total	**282**	**44**	**7**	**3**	**336**	**2656**	**253**	**52**	**15**	**2976**						

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Residential Low Income Assistance Program (RLIAP)

		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 14.0300	$ 0.2467	$ 0.1859		
3	R-4 Rate at 40% of R-3	$ 5.6100	$ 0.0987	$ 0.0744		
4	Program Subsidy	$ 8.4200	$ 0.1480	$ 0.1115		
5	Average Annual Therms		572	203	775	
6						
7	Peak Period RLIAP Subsidy	$ 50.52	$ 84.69	$ 22.62	$ 157.82	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 14.0300	$ 0.2467	$ 0.1859		
11	R-4 Rate at 40% of R-3	$ 5.6100	$ 0.0987	$ 0.0744		
12	Program Subsidy	$ 8.4200	$ 0.1480	$ 0.1115		
13	Average Annual Therms		118	52	170	
14						
15	Off Peak Period RLIAP Subsidy	$ 50.52	$ 17.49	$ 5.81	$ 73.82	
16						
17	Estimated Annual Subsidy	$ 101.04	$ 102.18	$ 28.43	$ 231.65	
18						
19	Number of Estimated 2009/10 Participants				6,466	1/
20						
21	Annual Subsidy times Number of Particpants (Ln 17 * Ln 19)				$ 1,497,827	
22	Prior Year Ending Balance - RLIAP Page 2				(14,753)	
23	Estimated Annual Administrative Costs				8,600	
24	Total Program Costs				$ 1,491,674	
25						
26	Estimated weather normalized firm therms billed for					
27	the twelve months ended 10/31/09 sales and transportation				150,828,182	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0099**	

1/ Estimated number of participants for 2009-10 is based on the actual number participants as of June 2009, as provided in the RLIAP Quarterly Report as revised and filed on July 20, 2009.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
NOVEMBER 2007 THROUGH OCTOBER 2008
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

											(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (326,147)	$ (390,062)	$ (459,612)	$ (431,678)	$ (368,511)	$ (343,442)	$ (247,260)	$ (192,147)	$ (142,455)	$ (109,618)	$ (77,480)	$ (47,769)	$ (326,147)
4														
5	Add: Actual Costs	4,354	67,525	213,987	245,784	173,695	206,491	120,113	95,847	70,098	68,052	68,352	76,977	1,411,275
6														
7	Less: Collected Revenue	(67,094)	(135,775)	(184,824)	(181,588)	(147,643)	(109,522)	(64,394)	(45,709)	(36,913)	(35,656)	(38,474)	(43,875)	(1,091,467)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (388,887)	$ (458,312)	$ (430,449)	$ (367,481)	$ (342,460)	$ (246,472)	$ (191,541)	$ (142,009)	$ (109,271)	$ (77,222)	$ (47,602)	$ (14,667)	**$ (6,339)**
12														
13	Month's Average Balance	$ (357,517)	$ (424,187)	$ (445,031)	$ (399,580)	$ (355,486)	$ (294,957)	$ (219,401)	$ (167,078)	$ (125,863)	$ (93,420)	$ (62,541)	$ (31,218)	
14														
15	Interest Rate	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16														
17	Interest Applied	$ (1,175)	$ (1,301)	$ (1,228)	$ (1,030)	$ (981)	$ (788)	$ (606)	$ (446)	$ (347)	$ (258)	$ (167)	$ (86)	**(8,414)**
18														
19	Ending Balance	**$ (390,062)**	**$ (459,612)**	**$ (431,678)**	**$ (368,511)**	**$ (343,442)**	**$ (247,260)**	**$ (192,147)**	**$ (142,455)**	**$ (109,618)**	**$ (77,480)**	**$ (47,769)**	**$ (14,753)**	**$ (14,753)**

Conservation Charge (CC) Factor Calculation

Conservation Charge Factors for Residential Customers (CCres)

DSM Expenses	$0	Backup Page 4 Line 7
Residential Lost Margins	$0	Backup Page 5 Line 5
Residential Conservation Reconciliation Adjustment (CCRres)	(31,762)	Backup Page 2 Line 11
Total Rate Case Expense Recoverable	($31,762)	
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	57,302,228	
Conservation Charge Factor for Residential Customers (CCres)	**-$0.0006**	

Conservation Charge Factors for Commercial Customers (CCcomm)

DSM Expenses	$0	Backup Page 4 Line 24
Commercial Lost Margins	$0	Backup Page 5 Line 16
Commercial Conservation Reconciliation Adjustment (CCRcomm)	(3,812)	Backup Page 2 Line 28
Total Rate Case Expense Recoverable	($3,812)	
Forecasted Annual Throughput Volumes for Commercial Customer (A:VOLcomm)	92,474,643	
Conservation Charge Factor for Commercial Customers (CCres)	**$0.0000**	

2007/2008 EnergyNorth Conservation Charge Reconciliation

		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate		
Line No.		2008	2008	2008	2009	2009	2009	2009	2009	2009	2009	2009	2009	
	Domestic Heating:	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
1	**Beginning balance**	2,739	$1,807	($621)	($5,126)	($11,673)	($18,146)	($23,284)	($26,867)	($28,694)	($29,895)	($30,863)	($31,630)	$2,739
2	Therms sold	1,882,596	4,049,171	7,494,363	10,873,470	10,722,175	8,469,210	5,859,354	2,919,457	1,869,371	1,476,985	1,137,129	-	56,753,281
3	Surcharge (Tariff Pg. 91)	(0.0005)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	(0.0006)	-	
4	Revenue collected	(941)	(2,430)	(4,497)	(6,524)	(6,433)	(5,082)	(3,516)	(1,752)	(1,122)	(886)	(682)	-	(33,864)
5	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Lost net rev (Pg 4 Ln.5)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Under/(over)	(941)	(2,430)	(4,497)	(6,524)	(6,433)	(5,082)	(3,516)	(1,752)	(1,122)	(886)	(682)	-	(33,864)
8	Pre-interest ending balance	1,798	(623)	(5,117)	(11,650)	(18,106)	(23,228)	(26,800)	(28,619)	(29,816)	(30,781)	(31,546)	(31,630)	(31,124)
9	Average monthly balance	2,269	592	(2,869)	(8,388)	(14,889)	(20,687)	(25,042)	(27,743)	(29,255)	(30,338)	(31,205)	(31,630)	(14,192)
10	Interest for month	9	2	(9)	(23)	(40)	(56)	(68)	(75)	(79)	(82)	(85)	(132)	(638)
11	**Month-end balance**	1,807	(621)	(5,126)	(11,673)	(18,146)	(23,284)	(26,867)	(28,694)	(29,895)	(30,863)	(31,630)	(31,762)	(31,762)
12	Interest rate	4.56%	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	5.00%	3.60%
13														
14		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate		
15		2008	2008	2008	2009	2009	2009	2009	2009	2009	2009	2009	2009	
16	**Commercial Heating:**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
17	**Beginning balance**	(3,678)	($3,692)	($3,704)	($3,715)	($3,725)	($3,735)	($3,745)	($3,756)	($3,766)	($3,776)	($3,786)	($3,796)	($3,678)
18	Therms sold	3,880,671	6,032,970	11,085,314	13,278,434	13,202,955	12,021,866	9,649,489	6,292,406	4,781,718	3,681,187	3,334,902	-	87,241,912
19	Surcharge (Tariff Pg. 91)	-	-	-	-	-	-	-	-	-	-	-	-	
20	Revenue collected	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Lost net rev (Pg 4 Ln.16)	-	-	-	-	-	-	-	-	-	-	-	-	-
23			-											-
24	Under/(over)	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Pre-interest ending balance	(3,678)	(3,692)	(3,704)	(3,715)	(3,725)	(3,735)	(3,745)	(3,756)	(3,766)	(3,776)	(3,786)	(3,796)	(3,678)
26	Average monthly balance	(3,678)	(3,692)	(3,704)	(3,715)	(3,725)	(3,735)	(3,745)	(3,756)	(3,766)	(3,776)	(3,786)	(3,796)	(3,678)
27	Interest for month	(14)	(12)	(11)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(16)	(135)
28	**Month-end balance**	(3,692)	(3,704)	(3,715)	(3,725)	(3,735)	(3,745)	(3,756)	(3,766)	(3,776)	(3,786)	(3,796)	(3,812)	(3,812)
29	Interest rate	4.56%	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	5.00%	
30														
31		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate		
32		2008	2008	2008	2009	2009	2009	2009	2009	2009	2009	2009	2009	
33	**TOTAL**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
34	**Beginning balance**	($938)	($1,885)	($4,325)	($8,841)	($15,398)	($21,882)	($27,029)	($30,623)	($32,460)	($33,671)	($34,650)	($35,427)	($938)
35	Therms sold	5,763,267	10,082,141	18,579,677	24,151,904	23,925,130	20,491,076	15,508,843	9,211,863	6,651,089	5,158,172	4,472,031	-	143,995,193
36	Revenue collected	(941)	(2,430)	(4,497)	(6,524)	(6,433)	(5,082)	(3,516)	(1,752)	(1,122)	(886)	(682)	-	(33,864)
37	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Lost net revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Under/(over)	(941)	(2,430)	(4,497)	(6,524)	(6,433)	(5,082)	(3,516)	(1,752)	(1,122)	(886)	(682)	-	(33,864)
40	Pre-interest ending balance	(1,880)	(4,314)	(8,821)	(15,365)	(21,831)	(26,963)	(30,545)	(32,375)	(33,582)	(34,557)	(35,332)	(35,427)	(34,802)
41	Interest for month	(5)	(10)	(20)	(33)	(50)	(66)	(78)	(85)	(89)	(92)	(95)	(148)	(772)
42	**Month-end balance**	(1,885)	(4,325)	(8,841)	(15,398)	(21,882)	(27,029)	(30,623)	(32,460)	(33,671)	(34,650)	(35,427)	(35,574)	(35,574)
43	Interest rate	4.56%	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	5.00%	

00001117

2007/2008 EnergyNorth Conservation Charge Reconciliation

Actual Throughput

Line No.		2008 OCT	2008 NOV	2008 DEC	2009 JAN	2009 FEB	2009 MAR	2009 APR	2009 MAY	2009 JUN	2009 JUL	2009 AUG	2009 SEP	TOTAL
	Domestic Heating:													
1	Therms sold - actual	1,882,596	4,049,171	7,494,363	10,873,470	10,722,175	8,469,210	5,859,354	2,919,457	1,869,371	1,476,985	1,137,129	1,267,830	58,021,111
2	Surcharge (Tariff Pg 61)	($0.0005)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	($0.0006)	
3	Revenue - actual	(941)	(2,430)	(4,497)	(6,524)	(6,433)	(5,082)	(3,516)	(1,752)	(1,122)	(886)	(682)	(761)	(34,624)
4														
5														
6														
7	**Commercial Heating:**													
8	Therms sold - actual	3,880,671	6,032,970	11,085,314	13,278,434	13,202,955	12,021,866	9,649,489	6,292,406	4,781,718	3,681,187	3,334,902	3,551,921	90,793,833
9	Surcharge (Tariff Pg 61)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
10	Revenue - actual	-	-	-	-	-	-	-	-	-	-	-	-	-
11														
12														
13	**Total:**													
14	Therms sold - actual	5,763,267	10,082,141	18,579,677	24,151,904	23,925,130	20,491,076	15,508,843	9,211,863	6,651,089	5,158,172	4,472,031	4,819,751	148,814,944
15	Revenue - actual	(941)	(2,430)	(4,497)	(6,524)	(6,433)	(5,082)	(3,516)	(1,752)	(1,122)	(886)	(682)	(761)	(34,624)

00000118

2007/2008 EnergyNorth Conservation Charge Reconciliation

Actual Expenses

Line No.		2008 OCT	2008 NOV	2008 DEC	2009 JAN	2009 FEB	2009 MAR	2009 APR	2009 MAY	2009 JUN	2009 JUL	2009 AUG	2009 SEP	TOTAL
	Residential Expenses Incurred													
1	Administrative	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Total Residential Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9														
10														
11	**Commercial Expenses Incurred**													
12														
13	Administrative:													
14	Delivery Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Photocopies	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Telephone	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Travel	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Legal	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
23														
24	Total Commercial Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-

2007/2008 ENERGYNORTH LOST MARGIN SUMMARY

Residential Heating

Line No.	fiscal 2008	2008 Oct	2008 Nov	2008 Dec	2009 Jan	2009 Feb	2009 Mar	2009 Apr	2009 May	2009 June	2009 July	2009 Aug	2009 Sep	TOTAL
1	Lost Vol Therms (Pg 6 Ln 29)												-	-
2	Tailblock Rate	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1711	$0.1767	$0.0000	
3	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	
5	Lost Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6														
7														
8														
9	**Commercial and Industrial:**													
10														
11	fiscal 2008													
12	Lost Vol Therms (Pg 5 Ln 53)													-
13	Tailblock Rate	$0.1551	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1551	$0.1551	$0.1551	$0.1601	$0.0000	
14	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	57%
16	Lost Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17														
18														
19	**Total**													
20														
21	fiscal 2008													
22	Lost Volume Therms	-	-	-	-	-	-	-	-	-	-	-	-	
23	Tailblock Rate													
24	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	recovery rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	57%
26	recoverable portion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

00000120

ENERGYNORTH 2007/2008 LOST MARGIN CALCULATION BACKUP

Line No. **Actual tailblock margin**

Line No.		Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	
1	**Domestic Heating**	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1767	0.1950	
2														
3	**Commercial Heating**	0.1551	0.1838	0.1838	0.1838	0.1838	0.1838	0.1838	0.1551	0.1551	0.1551	0.1601	0.1767	
4														
5	**Normal heating degree days (calendar):**													
6		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total
7														
8	Heating Degree Days													-
9														
10	Percent of Total													0.00%
11														

Residential Heating

Line No.		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	annual load	Pg 8 Ln32 F Y 97 Savings	Pg 7 Ln31 FY98 Savings	Pg 6 Ln14 FY99 Savings	FY00 Savings	FY01 Savings
12																				
13																				
14		Therms																		
15	**program year 2008**																			
16	**DH** - therm savings fiscal																			
17	Oct-06													-	15,432	8,616	6,816	-	0	0
18	Nov-06													-	16,450	3,455	12,996	-	0	0
19	Dec-06													-	25,866	4,342	15,945	5,579	0	0
20	Jan-07													-	25,818	4,088	6,134	15,596	0	0
21	Feb-07													-	36,373	9,277	12,457	14,639	0	0
22	Mar-07													-	31,547	8,055	14,524	8,969	0	0
23	Apr-07													-	36,059	10,465	17,113	8,481	0	0
24	May-07													-	16,633	11,922	4,711	-	0	0
25	Jun-07													-	32,762	23,809	7,258	1,695	0	0
26	Jul-07													-	15,798	12,412	3,386	-	0	0
27	Aug-07													-	17,875	12,514	1,331	4,030	0	0
28	Sep-07													-	34,800	28,758	5,981	61	0	0
29	totals	-	-	-	-	-	-	-	-	-	-	-	-	-	305,409	137,710	108,649	59,050	-	-
30																				
31	Rate	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1711	0.1767	0.1950							
32	Margin	-	-	-	-	-	-	-	-	-	-	-	-	-						
33	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
34		-	-	-	-	-	-	-	-	-	-	-	-	-						
35																				

Commercial Heating

Line No.		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	Total	Pg 8 Ln49 F Y 97 Savings	Pg 7 Ln48 FY98 Savings	FY99 Savings	FY00 Savings	FY01 Savings
36																				
37																				
38		Therms																		
39	**program year 2008**																			
40	**CH** - therm savings																			
41	Oct-06													-	189	-	189	0	0	0
42	Nov-06													-	567	378	189	0	0	0
43	Dec-06													-	1,189	439	750	0	0	0
44	Jan-07													-	945	189	756	0	0	0
45	Feb-07													-	399	189	210	0	0	0
46	Mar-07													-	945	378	567	0	0	0
47	Apr-07													-	189	-	189	0	0	0
48	May-07													-	378	-	378	0	0	0
49	Jun-07													-	1,256	567	689	0	0	0
50	Jul-07													-	549	549	-	0	0	0
51	Aug-07													-	189	189	-	0	0	0
52	Sep-07													-	1,000	-	1,000	0	0	0
53	totals													-	7,795	2,878	4,917	-	-	-
54																				
55	Rate	$0.1551	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1838	$0.1551	$0.1551	$0.1551	$0.1601	$0.1767							
56	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						
57	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
58	Total Recovery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						

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EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential Non Heating and Heating Classes
November 1, 2009 - October 31, 2010
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Actual DSM Expenditures Low-Income	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Monthly Federal Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Residential Therm Sales	Residential Therm Sales	# of Days
May 09	Actual	(235,716)	($0.0181)	(54,229)	166,400	73,928	51,397	(164,620)	(200,168)	**3.25%**	(553)	(165,172)	3,837,862	2,996,052	31
June 09	Actual	(165,172)	($0.0181)	(34,992)	166,400	93,725	158	(106,280)	(135,726)	3.25%	(363)	(106,643)	2,125,987	1,933,247	30
July 09	Actual	(106,643)	($0.0181)	(27,841)	166,400	0	0	31,916	(37,364)	3.25%	(103)	31,813	1,434,266	1,538,162	31
August 09	Forecast	31,813	($0.0181)	(22,968)	166,400	0	0	175,244	103,528	3.25%	286	175,530	1,268,968	0	31
September 09	Forecast	175,530	($0.0181)	(24,687)	166,400	0	0	317,242	246,386	3.25%	658	317,900	1,363,950	0	30
October 09	Forecast	317,900	($0.0181)	(32,684)	166,400	0	0	451,616	384,758	3.25%	1,062	452,678	1,805,758	0	31
November 09	Forecast	452,678	($0.0466)	(188,688)	166,400	0	0	430,389	441,533	3.25%	1,179	431,568	4,045,632	0	30
December 09	Forecast	431,568	($0.0466)	(348,766)	166,400	0	0	249,202	340,385	3.25%	940	250,141	7,477,835	0	31
January 10	Forecast	250,141	($0.0466)	(477,499)	194,285	0	0	(33,072)	108,535	3.25%	300	(32,773)	10,237,973	0	31
February 10	Forecast	(32,773)	($0.0466)	(478,805)	194,285	0	0	(317,292)	(175,032)	3.25%	(436)	(317,729)	10,265,978	0	28
March 10	Forecast	(317,729)	($0.0466)	(407,774)	194,285	0	0	(531,217)	(424,473)	3.25%	(1,172)	(532,388)	8,743,001	0	31
April 10	Forecast	(532,388)	($0.0466)	(291,317)	194,285	0	0	(629,420)	(580,904)	3.25%	(1,552)	(630,972)	6,246,084	0	30
May 10	Forecast	(630,972)	($0.0466)	(172,099)	194,285	0	0	(608,785)	(619,879)	3.25%	(1,711)	(610,496)	3,689,942	0	31
June 10	Forecast	(610,496)	($0.0466)	(86,282)	194,285	0	0	(502,493)	(556,495)	3.25%	(1,487)	(503,979)	1,849,958	0	30
July 10	Forecast	(503,979)	($0.0466)	(62,947)	194,285	0	0	(372,641)	(438,310)	3.25%	(1,210)	(373,851)	1,349,637	0	31
August 10	Forecast	(373,851)	($0.0466)	(55,524)	194,285	0	0	(235,089)	(304,470)	3.25%	(840)	(235,930)	1,190,474	0	31
September 10	Forecast	(235,930)	($0.0466)	(60,650)	194,285	0	0	(102,294)	(169,112)	3.25%	(452)	(102,746)	1,300,391	0	30
October 10	Forecast	(102,746)	($0.0466)	(91,257)	194,285	0	0	282	(51,232)	3.25%	(141)	141	1,956,634	0	31
November 10	Forecast	141	($0.0466)	(188,688)	194,285	0	0	5,738	2,939	3.25%	8	5,746	4,045,632	0	30
December 10	Forecast	5,746	($0.0466)	(348,766)	194,285	0	0	(148,735)	(71,495)	3.25%	(197)	(148,932)	7,477,835	0	31

Estimated Residential Nonheating Conservation Charge Effective November 1, 2009 - October 31, 2010		
Beginning Balance	$	452,678
Program Budget Nov 09-Oct 10		2,275,654
Projected Interest		(6,582)
Projected Budget with Interest	$	2,721,750
Total Charges	**$**	**2,721,750**
Projected Therm Sales		**58,353,540**
Residential Rate		**$0.0466**
Total Charges with Interest	**$**	**2,721,750**
Projected Therm Sales		**58,353,540**
Residential Rate		**$0.0466**

Residential Non Heating Therm Sales	**1,051,312**	1%
Residential Heating Therm Sales	**57,302,228**	38%
C&I Therm Sales	**92,474,643**	61%
Total Therms	**150,828,182**	100%

	Year One Budget 5/01/09 - 12/31/09	Year Two Budget 1/01/10 - 12/31/10
Low-Income Program Budget	**$ 404,540**	**$ 635,997**
Other Refund	-	-
Total Shared Budget	**$ 404,540**	**$ 635,997**
Residential Program Budget	**$ 1,174,686**	1,939,128
Residential Program Incentive		**146,238**
Total Residential Program Budget	**$ 1,174,686**	**$ 2,085,366**
Commercial/Industrial Program Budget	**$ 1,236,560**	**$ 2,411,290**
Commercial/Industrial Program Incentive		**154,045**
Total Commercial/Industrial Program Budget	**$ 1,236,560**	**$ 2,565,335**
Total Program Budget	**$ 2,815,786**	**$ 5,286,699**
Shared Expenses Allocation to Residential	$ 156,512	$ 246,059
Shared Expenses Allocation to C&I	248,029	389,938
Total Allocated Shared Expenses	**$ 404,540**	**$ 635,997**
Total Residential (including allocation of Shared Budget)	$ 1,331,197	$ 2,331,426
Total C&I (including allocation of Shared Budget)	1,484,588	2,955,273
Total Budget	**$ 2,815,786**	**$ 5,286,699**

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EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2009 - October 31, 2010
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Com-Ind	Actual DSM Expenditures Low-Income	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Fed Reserve Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Commercial/ Industrial Therm Sales	Commercial/ Industrial Therm Sales	# of Days
May 09	Actual	(985,545)	($0.0205)	(119,413)	185,574	133,986	68,131	(902,842)	(944,194)	**3.25%**	(2,606)	(905,448)	5,918,532	5,825,035	31
June 09	Actual	(905,448)	($0.0205)	(88,729)	185,574	66,537	210	(927,430)	(916,439)	3.25%	(2,448)	(929,878)	4,712,279	4,328,233	30
July 09	Actual	(929,878)	($0.0205)	(73,773)	185,574	0	0	(818,077)	(873,978)	3.25%	(2,412)	(820,490)	3,598,666	0	31
August 09	Forecast	(820,490)	($0.0205)	(73,648)	185,574	0	0	(708,564)	(764,527)	3.25%	(2,110)	(710,674)	3,592,564	0	31
September 09	Forecast	(710,674)	($0.0205)	(79,577)	185,574	0	0	(604,678)	(657,676)	3.25%	(1,757)	(606,435)	3,881,786	0	30
October 09	Forecast	(606,435)	($0.0205)	(85,614)	185,574	0	0	(506,475)	(556,455)	3.25%	(1,536)	(508,011)	4,176,311	0	31
November 09	Forecast	(508,011)	($0.0250)	(166,044)	185,574	0	0	(488,482)	(498,246)	3.25%	(1,331)	(489,813)	6,641,777	0	30
December 09	Forecast	(489,813)	($0.0250)	(249,489)	185,574	0	0	(553,728)	(521,770)	3.25%	(1,440)	(555,168)	9,979,574	0	31
January 10	Forecast	(555,168)	($0.0250)	(337,512)	246,273	0	0	(646,407)	(600,788)	3.25%	(1,658)	(648,066)	13,500,470	0	31
February 10	Forecast	(648,066)	($0.0250)	(344,753)	246,273	0	0	(746,546)	(697,306)	3.25%	(1,738)	(748,285)	13,790,117	0	28
March 10	Forecast	(748,285)	($0.0250)	(312,377)	246,273	0	0	(814,389)	(781,337)	3.25%	(2,157)	(816,546)	12,495,077	0	31
April 10	Forecast	(816,546)	($0.0250)	(230,637)	246,273	0	0	(800,910)	(808,728)	3.25%	(2,160)	(803,070)	9,225,488	0	30
May 10	Forecast	(803,070)	($0.0250)	(160,380)	246,273	0	0	(717,177)	(760,124)	3.25%	(2,098)	(719,276)	6,415,202	0	31
June 10	Forecast	(719,276)	($0.0250)	(121,033)	246,273	0	0	(594,036)	(656,656)	3.25%	(1,754)	(595,790)	4,841,323	0	30
July 10	Forecast	(595,790)	($0.0250)	(93,975)	246,273	0	0	(443,492)	(519,641)	3.25%	(1,434)	(444,926)	3,759,005	0	31
August 10	Forecast	(444,926)	($0.0250)	(87,325)	246,273	0	0	(285,979)	(365,453)	3.25%	(1,009)	(286,988)	3,492,988	0	31
September 10	Forecast	(286,988)	($0.0250)	(97,837)	246,273	0	0	(138,552)	(212,770)	3.25%	(568)	(139,120)	3,913,470	0	30
October 10	Forecast	(139,120)	($0.0250)	(110,504)	246,273	0	0	(3,351)	(71,236)	3.25%	(197)	(3,548)	4,420,152	0	31
November 10	Forecast	(3,548)	($0.0250)	(166,044)	246,273	0	0	76,681	36,566	3.25%	98	76,778	6,641,777	0	30
December 10	Forecast	76,778	($0.0250)	(249,489)	246,273	0	0	73,562	75,170	3.25%	207	73,770	9,979,574	0	31

0

Estimated C & I Conservation Charge Effective November 1, 2009 - October 31, 2010	
Beginning Balance	($508,011)
Program Budget	2,833,874
Projected Interest	(17,545)
Program Budget with Interest	$2,308,318
Total Charges	**$2,308,318**
Projected Therm Sales	**92,474,643**
C&I Rate	$0.0250
Total Charges with Interest	**$2,308,318**
Projected Therm Sales	**92,474,643**
Com/Ind Rate	**$0.0250**
Com/Ind Rate from Prior Programs (1)	**$0.0000**
Combined Com/Ind Rate	**$0.0250**

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EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2009 - October 31, 2010
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures				Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Therm Sales	# of Days
						Residential	Com-Ind	Low-Income	Total								
May 09	Actual	(1,221,261)	n/a	(173,642)	351,973	73,928	133,986	119,528	327,441	(1,067,461)	(1,144,361)	**3.25%**	(3,159)	(1,070,620)	9,756,394	8,821,087	31
June 09	Actual	(1,070,620)	n/a	(123,721)	351,973	93,725	66,537	369	160,631	(1,033,710)	(1,052,165)	3.25%	(2,811)	(1,036,521)	6,838,266	6,261,480	30
July 09	Actual	(1,036,521)	n/a	(101,614)	351,973	0	0	0	0	(786,161)	(911,341)	3.25%	(2,516)	(788,677)	5,032,932	1,538,162	31
August 09	Forecast	(788,677)	n/a	(96,616)	351,973	0	0	0	0	(533,320)	(660,999)	3.25%	(1,825)	(535,145)	4,861,531	0	31
September 09	Forecast	(535,145)	n/a	(104,264)	351,973	0	0	0	0	(287,436)	(411,290)	3.25%	(1,099)	(288,535)	5,245,736	0	30
October 09	Forecast	(288,535)	n/a	(118,298)	351,973	0	0	0	0	(54,860)	(171,697)	3.25%	(474)	(55,333)	5,982,070	0	31
November 09	Forecast	(55,333)	n/a	(354,732)	351,973	0	0	0	0	(58,093)	(56,713)	3.25%	(151)	(58,244)	10,687,409	0	30
December 09	Forecast	(58,244)	n/a	(598,255)	351,973	0	0	0	0	(304,526)	(181,385)	3.25%	(501)	(305,027)	17,457,408	0	31
January 10	Forecast	(305,027)	n/a	(815,011)	440,558	0	0	0	0	(679,480)	(492,253)	3.25%	(1,359)	(680,838)	23,738,443	0	31
February 10	Forecast	(680,838)	n/a	(823,558)	440,558	0	0	0	0	(1,063,838)	(872,338)	3.25%	(2,175)	(1,066,013)	24,056,096	0	28
March 10	Forecast	(1,066,013)	n/a	(720,151)	440,558	0	0	0	0	(1,345,606)	(1,205,809)	3.25%	(3,328)	(1,348,934)	21,238,078	0	31
April 10	Forecast	(1,348,934)	n/a	(521,954)	440,558	0	0	0	0	(1,430,330)	(1,389,632)	3.25%	(3,712)	(1,434,042)	15,471,572	0	30
May 10	Forecast	(1,434,042)	n/a	(332,479)	440,558	0	0	0	0	(1,325,963)	(1,380,002)	3.25%	(3,809)	(1,329,772)	10,105,145	0	31
June 10	Forecast	(1,329,772)	n/a	(207,315)	440,558	0	0	0	0	(1,096,529)	(1,213,150)	3.25%	(3,241)	(1,099,769)	6,691,280	0	30
July 10	Forecast	(1,099,769)	n/a	(156,922)	440,558	0	0	0	0	(816,133)	(957,951)	3.25%	(2,644)	(818,777)	5,108,643	0	31
August 10	Forecast	(818,777)	n/a	(142,849)	440,558	0	0	0	0	(521,068)	(669,923)	3.25%	(1,849)	(522,917)	4,683,462	0	31
September 10	Forecast	(522,917)	n/a	(158,487)	440,558	0	0	0	0	(240,846)	(381,882)	3.25%	(1,020)	(241,866)	5,213,861	0	30
October 10	Forecast	(241,866)	n/a	(201,761)	440,558	0	0	0	0	(3,069)	(122,468)	3.25%	(338)	(3,407)	6,376,786	0	31
November 10	Forecast	(3,407)	n/a	(354,732)	440,558	0	0	0	0	82,418	39,506	3.25%	106	82,524	10,687,409	0	30
December 10	Forecast	82,524	n/a	(598,255)	440,558	0	0	0	0	(75,173)	3,675	3.25%	10	(75,163)	17,457,408	0	31

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 1, 2009 - October 31, 2010	
Beginning Balance	$ (55,333.49)
Program Budget	5,109,528.62
Projected Interest	(24,127.49)
Program Budget with Interest	$5,030,068
Total Charges	**$5,030,068**

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New Hampshire Program Year ONE (May 1, 2009 - December 31, 2009)

Program	Services	Vendor Admin/Support	Company Admin	Communication	Trade Ally Training	Evaluation & Reporting	Other	Budget Total	Participant Goal
Residential									
Low Income	$ 252,536	$ 79,060	$ 57,744	$ 5,641	$ 2,583	$ 6,976	$ -	$ 404,540	180
Residential Weatherization	$ 462,090	$ 27,307	$ 17,571	$ 56,549	$ 25,931	$ 5,408	$ -	$ 594,856	550
Residential High Efficiency Heating	$ 157,833	$ 6,781	$ 18,893	$ 100,215	$ 22,001	$ 13,463	$ -	$ 319,187	404
Residential Water Heating	$ 49,951	$ 1,377	$ 3,832	$ 8,560	$ 5,000	$ 1,839	$ -	$ 70,559	131
ES Windows	$ 30,000	$ 6,327	$ 4,026	$ 18,628	$ 1,150	$ 0	$ -	$ 60,132	300
Advanced Residential Controls	$ 18,589	$ 667	$ 1,860	$ 4,147	$ 3,000	$ 1,327	$ -	$ 29,589	212
ES Homes	$ 10,800	$ 1,980	$ 1,260	$ 2,700	$ 360	$ 1,415	$ -	$ 18,515	20
Energy Analysis: Internet Audit	$ 8,404	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,404	660
Energy Audit and Home Performance	$ 30,333	$ 3,158	$ 2,009	$ 8,198	$ 574	$ 3,028	$ -	$ 47,300	450
Building Practices and Demo	$ 14,999	$ 2,750	$ 1,750	$ 3,750	$ 500	$ 2,394	$ -	$ 26,144	15
Net Zero Energy Homes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
Air Sealing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	225
Residential Total	**$ 1,035,536**	**$ 129,407**	**$ 108,946**	**$ 208,388**	**$ 61,098**	**$ 35,851**	**$ -**	**$ 1,579,226**	**2,922**
Commercial & Industrial									
Comm Energy Efficiency Program	$ 481,640	$ 28,095	$ 45,000	$ 25,000	$ 10,000	$ 28,549	$ -	$ 618,284	109
Multifamily Housing Program	$ 26,490	$ 14,960	$ 17,000	$ 8,000	$ 5,000	$ 2,210	$ -	$ 73,660	10
Comm High Efficiency Heating	$ 124,296	$ 15,620	$ 20,000	$ 10,000	$ 10,000	$ 5,564	$ -	$ 185,480	90
Economic Redevelopment	$ 124,296	$ 12,620	$ 30,000	$ 8,000	$ 5,000	$ 5,564	$ -	$ 185,480	4
Building Practices and Demo	$ 58,290	$ 15,000	$ 31,656	$ 5,000	$ -	$ 13,710	$ -	$ 123,656	2
Energy Analysis: Internet Audit	$ -	$ 5,000	$ 10,000	$ 5,000	$ -	$ -	$ -	$ 20,000	40
Building Operator Certification	$ 12,000	$ 5,000	$ 10,000	$ 3,000	$ -	$ -	$ -	$ 30,000	20
Commercial Total	**$ 827,012**	**$ 96,295**	**$ 163,656**	**$ 64,000**	**$ 30,000**	**$ 55,597**	**$ -**	**$ 1,236,560**	**275**
GRAND TOTAL	**$ 1,862,548**	**$ 225,702**	**$ 272,602**	**$ 272,388**	**$ 91,098**	**$ 91,448**	**$ -**	**$ 2,815,786**	**3,197**

New Hampshire Program Year TWO (January 2010 - December 31, 2010)

Program	Services	Vendor Admin/Support	Company Admin	Communication	Trade Ally Training	Evaluation & Reporting	Other	Budget Total	Participant Goal
Residential									
Low Income	$ 397,977	$ 124,376	$ 90,847	$ 8,890	$ 4,070	$ 9,838	$ -	$ 635,997	260
Residential Weatherization	$ 901,484	$ 61,372	$ 34,464	$ 88,436	$ 42,929	$ 3,380	$ -	$ 1,132,065	1,100
Residential High Efficiency Heating	$ 254,000	$ 10,120	$ 28,200	$ 142,600	$ 22,000	$ 19,880	$ -	$ 476,800	551
Residential Water Heating	$ 77,730	$ 2,055	$ 5,720	$ 12,180	$ 5,000	$ 2,715	$ -	$ 105,400	257
ES Windows	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
Advanced Residential Controls	$ 29,570	$ 995	$ 2,775	$ 5,900	$ 3,000	$ 1,960	$ -	$ 44,200	704
ES Homes	$ 14,400	$ 2,640	$ 1,680	$ 3,600	$ 480	$ 2,044	$ -	$ 24,844	30
Energy Analysis: Internet Audit	$ 16,007	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,007	1,053
Energy Audit and Home Performance	$ 57,020	$ 5,955	$ 3,789	$ 15,460	$ 1,083	$ 5,893	$ -	$ 89,200	900
Building Practices and Demo	$ 30,000	$ 5,500	$ 3,500	$ 7,500	$ 1,000	$ 3,112	$ -	$ 50,612	20
Net Zero Energy Homes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
Air Sealing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	450
Residential Total	**$ 1,778,189**	**$ 213,013**	**$ 170,975**	**$ 284,565**	**$ 79,561**	**$ 48,822**	**$ -**	**$ 2,575,126**	**4,875**
Commercial & Industrial									
Comm Energy Efficiency Program	$ 930,061	$ 71,415	$ 98,000	$ 35,000	$ 25,000	$ 46,169	$ -	$ 1,205,645	227
Multifamily Housing Program	$ 83,342	$ 23,895	$ 30,000	$ 15,000	$ 10,000	$ 5,018	$ -	$ 167,255	20
Comm High Efficiency Heating	$ 260,844	$ 20,000	$ 30,000	$ 15,000	$ 15,000	$ 20,851	$ -	$ 361,695	160
Economic Redevelopment	$ 261,334	$ 17,000	$ 45,000	$ 10,010	$ 7,500	$ 20,851	$ -	$ 361,695	10
Building Practices and Demo	$ 150,000	$ 22,500	$ 40,000	$ 15,000	$ -	$ 22,500	$ -	$ 250,000	3
Energy Analysis: Internet Audit	$ -	$ 7,500	$ 12,500	$ 5,000	$ -	$ -	$ -	$ 25,000	60
Building Operator Certification	$ 20,000	$ 6,000	$ 11,000	$ 3,000	$ -	$ -	$ -	$ 40,000	60
Commercial Total	**$ 1,705,581**	**$ 168,310**	**$ 266,500**	**$ 98,010**	**$ 57,500**	**$ 115,389**	**$ -**	**$ 2,411,290**	**540**
GRAND TOTAL	**$ 3,483,770**	**$ 381,323**	**$ 437,475**	**$ 382,575**	**$ 137,061**	**$ 164,211**	**$ -**	**$ 4,986,415**	**5,415**

Exhibit-C: KeySpan Energy Delivery - NH DSM/MT Program Year Three (2008-2009): Shareholder Incentive Calculation - August 27, 2009

Program	Expenditures (Budget) for Program Year 2 *	Design Goal for PY 1 *		Projected Lifetime Therms Savings	Actual Lifetime Therm Savings[2]	Actual LTT/Projected LTT	Projected TRC[3] *	Actual TRC[4]	Actual TRC/Projected TRC	Lifetime Savings Incentive	Cost-effectiveness Incentive	Actual Pre Tax Design Incentive
Residential												
Low Income	$ 442,864	160	Participants	1,082,880	1,536,336	1.419	3.50	6.05	1.73			
Residential Weatherization	$ 89,557	45	Rebates	331,200	1,449,920	4.378	3.52	7.20	2.04			
Residential High Efficiency Heating	$ 271,179	500	Rebates	1,760,000	2,319,680	1.318	7.10	6.14	0.86			
Residential High Efficiency Water Heating	$ 81,708	150	Rebates	227,100	292,202	1.287	3.20	3.17	0.99			
Energy Star Windows	$ 63,008	300	Rebates	168,225	128,412	0.763	2.81	3.08	1.10			
Energy Star Residential Controls	$ 35,231	325	Rebates	254,625	560,535	2.201	6.91	12.81	1.85			
Energy Star Homes	$ 65,561	55	Participants	0	0		0.00					
Energy Analysis: Internet Audit Guide	$ 43,136	600	New Users	0.000	0.00		0.00					
Building Practices and Demo	$ 46,291	12	Projects	0.000	0.00		0.00					
Residential Conservation Services	$ 86,459	200	Participants	0.000	0.00		0.00					
Total	$ 1,224,992	2,347		3,824,030	6,287,085	1.644	3.70	5.31	1.4362	$ 80,256	$ 65,983	$ 146,238
C&I and Mutifamily												
Commercial Energy Efficiency Program	$ 542,617	150	Participants	1,647,585	746,905	0.453	2.91	1.75	0.60			
Multifamily Housing	$ 195,773	60	Participants	458,298	122,213	0.267	2.43	1.13	0.47			
Commercial High Efficiency Heating	$ 121,803	50	Rebates	996,000	4,362,480	4.380	6.44	10.36	1.61			
Economic Redevelopment	$ 330,182	3	Projects	591,396	2,562,717	4.333	2.56	29.21	11.39			
Commercial Building Practices & Tecnology Demonstration	$ 215,301	6	Projects	2,368,277	789,426	0.333	15.7	134.75	8.56			
C&I Energy Analysis Internet Audit	$ 21,122	50	New Users	0	0		0.00	0.00				
Total - C&I and Multifamily	$ 1,426,799	319		6,061,556	8,583,741	1.416	4.52	7.30	1.61	$ 80,819	$ 73,226	$ 154,045
Total of Column	$2,651,791										**TOTAL Incentive**	**$ 300,283**

Notes:

This shareholder incentive calculation is based on the methodology described in NH PUC Order 24,109 of December 31, 2002.

Threshold: KeySpan must achieve a minimum "threshold" performance before being eligible to earn an incentive

For the cost-effectiveness component, KeySpan must achieve an actual year-end TRC of 1.0 before any incentive can be earned

Once the threshold is achieved, the earned incentive will be on a sliding scale from 0% to 12%

Assumptions:

Design Target Incentive = 8%

Incentive Calculation Formula: $Incentive_{res} = Expenditures_{RES} \times \{[4\% \times (TRC_{Actual} / TRC_{Projected})] + [4\% \times Lifetime\ Therm\ Savings_{Actual} / Lifetime\ Therm\ Savings_{Projected})]\}$

Plus

$Incentive_{C\&I} = Expenditures_{C\&I} \times \{[4\% \times (TRC_{Actual} / TRC_{Projected})] + [4\% \times Lifetime\ Therm\ Savings_{Actual} / Lifetime\ Therm\ Savings_{Projected})]\}$

[1]Per a September 9, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the projected lifetime therm savings for each KED New Hampshire natural gas energy efficiency program and the source of the projected benefit/cost ratios by program is KeySpan's response to NH PUC Staff Data Request 2-31, Pages 3 to 6, Docket DG 04-152, filed by attorney Steven V. Camerino on November 22, 2004).

[2]From the updated Exhibit G showing actual Program Year 1 results.

[3,4,5] Per a September 20, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the Lifetime savings and Cost Effectiveness incentive calculations are derived from the updated and streamlined version of the template used by the PUC called "Computation of Actual Performance Incetive-Program Year Two" of DG 02-106 and DG 05-141.
In the Commission approved Settlement Agreement that is part of Order 24,109, the Settling Parties and Staff agree to adopt the simplified Staff template of November 2002 ("Staff Template") attached to the Settlement Agreement as Exhibit G. This template shall be used only for purposes of establishing a benchmark for the Gas Utilities' incentive sharing mechanism described in Section II(H) of the Settlement Agreement. The Staff Template allows for an evaluation of the Programs on a year-by-year basis.

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Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual increase in rates	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/09- sales and transportation	150,828,182	therms
Surcharge per therm	$0.0000	per therm
Total Environmental Surcharge	$0.0000	

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

Concord Pond

internal order no. 500061 (formerly acc no. 1796)

	(thru 3/98) pool #1	(4/98 - 9/98) pool #2	(10/98 - 9/15/99) pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	(9/08 - 9/09) pool #10	subtotal
Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	6,107,410
Remediation costs (i.o. 500005)	-	-	-	-							-
A Subtotal - remediation costs	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	6,107,410
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)			(14,314)	(13,446)	-	(12,608)	(2,088,312)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-							(445,985)
Recovery costs (i.o. 500004)	623,784	-	-	-				-	-	-	623,784
Transfer Credit from Gas Restructuring											-
B Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(1,910,513)
A-B Total net expenses to recover	520,030	1,409,330	1,654,552	95,798	60,293	21,613	81,979	142,350	95,374	115,579	4,196,897
Surcharge revenue:											
actual June 1998 - October 1998	(54,889)	-	-	-							(54,889)
actual November 1998 - October 1999	(287,010)	(251,133)	-	-							(538,143)
actual November 1999 - October 2000	(178,131)	(266,400)	(316,340)	-							(760,871)
actual November 2000 - October 2001	-	(292,420)	(334,194)	(13,925)							(640,539)
actual November 2001 - October 2002	-	(281,914)	(318,686)	(24,514)							(625,114)
actual November 2002 - October 2003	-	(258,347)	(334,331)	(15,197)							(607,874)
actual November 2003 - October 2004	-	(14,567)	(276,773)	(14,567)							(305,907)
Actual November 2004- October 2005	-	-	(56,719)	(14,180)	(14,180)						(85,078)
Actual November 2005- October 2006	-	-	-	(6,875)	(6,875)						(13,750)
Actual November 2006- October 2007	-	-	-	-	-	-	(14,091)				(14,091)
Actual November 2007- October 2008											-
AES collections					(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(12,888)	(94,876)
Gas Street overcollection	-	(23,511)									(23,511)
Prior Period Pool under/overcollection		-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	
C Surcharge Subtotal	(520,030)	(1,388,292)	(1,616,004)	(50,710)	(9,559)	39,108	34,729	104,437	234,190	(12,888)	(3,764,642)
D Net balance to be recovered (A-B+C)	-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,564	102,691	432,255
E Allocation of Litigated Recovery					-		-		(329,564)	-	(329,564)
Surcharge calculation 2007/2008											
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	102,691	102,691
remaining life	-	-	-	-	24	36	48	60	72	84	
one year	-	-	-	-	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-		-	14,670	
Required annual increase in rates 2007/2008: smaller of D or F	-	-	-	-	-	-	-		-	14,670	14,670
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000129

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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		Laconia & Liberty Hill								
		i.o. no. 500005 (through 9/15/99) pool #1	**(9/99 - 9/00) pool #2**	**(9/00 - 9/01) pool #3**	**(9/04 - 9/05) pool #4**	**(9/05 - 9/06) pool #5**	**(9/06 - 9/07) pool #6**	**(9/07 - 9/08) pool #7** Incl. Audit Corr	**(9/08 - 9/09) pool #8**	**subtotal**
	Remediation costs (i.o. 500061)	-	-		-					-
	Remediation costs (i.o. 500005)	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	624,557	10,723,270
A	Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	624,557	10,723,270
	Cash recoveries (i.o. 500061)	-	-	-	-	-	-	-	-	-
	Cash recoveries (i.o. 500004)	-	-	-	-	-	-	-	-	-
	Recovery costs (i.o. 500004)	-	-	-			11,643	21,729	-	33,372
	Transfer Credit from Gas Restructuring						-	-	-	-
B	Subtotal - net recoveries	-	-	-	-	-	11,643	21,729	-	33,372
A-B	Total net expenses to recover	1,027,747	3,513,285	700,000	9,702	2,330,555	2,100,842	449,954	624,557	10,756,642
	Surcharge revenue:									
actual	June 1998 - October 1998	-	-	-	-	-		-	-	-
actual	November 1998 - October 1999	-	-	-	-	-		-	-	-
actual	November 1999 - October 2000	(151,933)	-	-	-	-		-	-	(151,933)
actual	November 2000 - October 2001	(153,172)	(543,065)	-	-	-		-	-	(696,237)
actual	November 2001 - October 2002	(159,343)	(527,057)	(110,314)	-	-		-	-	(796,714)
actual	November 2002 - October 2003	(151,969)	(547,087)	(106,378)	-	-		-	-	(805,434)
actual	November 2003 - October 2004	(131,103)	(466,143)	(101,969)						(699,215)
Actual	November 2004- October 2005	(127,617)	(439,570)	(85,078)						(652,264)
Actual	November 2005- October 2006	(141,176)	(453,736)	(96,247)	-	-		-	-	(691,159)
Actual	November 2006- October 2007	-	(549,539)	(98,635)	-	(309,996)				(958,171)
Actual	November 2007- October 2008									-
	AES collections									-
	Gas Street overcollection									-
	Prior Period Pool under/overcollection		11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	-	
C	Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	-	(5,451,127)
D	Net balance to be recovered (A-B+C)	11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	4,680,958	624,557	5,305,515
E	Allocation of Litigated Recovery							(4,680,958)	-	(4,680,958)
	Surcharge calculation 2007/2008									
	Unrecovered costs (D+E)	-	-	-	-			-	624,557	624,557
	remaining life	-	-	-	36	48	60	72	84	
	one year	-	-	-	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	89,222	
	Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-	-		-	89,222	89,222
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0006	$0.0006

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000130

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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Manchester

		(9/00 - 9/01) pool #1	(9/02 - 9/03) pool #2	(9/02 - 9/03) pool #3 (withdrawn 2/1/04)	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8 Incl. Audit Corr	(9/08 - 9/09) pool #9	subtotal
	Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	8,461,928
	Remediation costs (i.o. 500005)	495,106	329,986								825,092
A	Subtotal - remediation costs	495,106	329,986	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	9,287,020
	Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)	-	(1,893,328)
	Cash recoveries (i.o. 500004)	-	-								-
	Recovery costs (i.o. 500004)	-	-		1,242,326			2,546	-	-	1,244,872
	Transfer Credit from Gas Restructuring							-	-	-	-
B	Subtotal - net recoveries	-	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(648,457)
A-B	Total net expenses to recover	495,106	329,986	-	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	8,638,563
	Surcharge revenue:										
actual	June 1998 - October 1998	-	-	-	-						-
actual	November 1998 - October 1999	-	-	-	-						-
actual	November 1999 - October 2000	-	-	-	-						-
actual	November 2000 - October 2001	-	-	-	-						-
actual	November 2001 - October 2002	(73,543)	-	-	-						(73,543)
actual	November 2002 - October 2003	(75,984)	-	-	-						(75,984)
actual	November 2003 - October 2004	(72,835)	(24,416)	(41,325)	-						(138,576)
Actual	November 2004- October 2005	(70,898)	(42,539)	-	(212,695)	-			-	-	(326,132)
Actual	November 2005- October 2006	(54,998)	(41,249)	-	(206,243)	(261,242)			-	-	(563,732)
Actual	November 2006- October 2007	(70,454)	(56,363)	-	(211,361)	(281,815)	(42,272)				(662,265)
Actual	November 2007- October 2008										-
	AES collections										-
	Gas Street overcollection										-
	Prior Period Pool under/overcollection		76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	-	
C	Surcharge Subtotal	(418,713)	(88,173)	200,488	(429,812)	604,796	2,552,371	2,882,534	3,225,936	-	(1,840,233)
D	Net balance to be recovered (A-B+C)	76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	6,486,145	312,185	6,798,331
E	Allocation of Litigated Recovery			-	-	-			(6,486,145)	-	(6,486,145)
	Surcharge calculation 2007/2008										
	Unrecovered costs (D+E)	-	-	-	-	-	-		-	312,185	312,185
	remaining life	-	-	-	24	36	48	60	70	84	
	one year	-	-	-	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	-	44,598	
	Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-	-	-		-	44,598	44,598
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	$0.0003

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000131

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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	Nashua									
	(9/00 - 9/01) pool #1	**(9/01 - 9/02) pool #2**	**(9/02 - 9/03) pool #3**	**(9/03 - 9/04) pool #4**	**(9/04 - 9/05) pool #5**	**(9/05 - 9/06) pool #6**	Corrected per 2/08 Audit **(9/06 - 9/07) pool #7**	**(9/07 - 9/08) pool #8**	**(9/08 - 9/09) pool #9**	**subtotal**
Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	78,535	436,439
Remediation costs (i.o. 500005)	1,233,726	362,663	175,178							1,771,567
A Subtotal - remediation costs	1,233,726	362,663	175,178	10,841	206,367	23,354	9,737	107,605	78,535	2,208,005
										-
Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(95,392)
Cash recoveries (i.o. 500004)	-	-	-							-
Recovery costs (i.o. 500004)	-	-	-			5,449	12,938	-	-	18,388
Transfer Credit from Gas Restructuring							-	-	-	-
B Subtotal - net recoveries	-	-	-	-		(13,131)	8,787	(10,414)	(62,246)	(77,004)
										-
A-B Total net expenses to recover	1,233,726	362,663	175,178	10,841	206,367	10,223	18,524	97,191	16,289	2,131,001
Surcharge revenue:										
actual June 1998 - October 1998	-	-	-	-						-
actual November 1998 - October 1999	-	-	-	-						-
actual November 1999 - October 2000	-	-	-	-						-
actual November 2000 - October 2001	-	-	-	-						-
actual November 2001 - October 2002	(183,857)	-	-	-						(183,857)
actual November 2002 - October 2003	(182,362)	(60,787)	-	-						(243,150)
actual November 2003 - October 2004	(174,804)	(43,701)	(29,134)	-						(247,639)
Actual November 2004- October 2005	(170,156)	(42,539)	(28,359)	-						(241,054)
Actual November 2005- October 2006	(164,995)	(54,998)	(27,499)	-	(27,499)			-	-	(274,991)
Actual November 2006- October 2007	(169,089)	(56,363)	(28,181)	-	(28,181)	-				(281,815)
Actual November 2007- October 2008										-
AES collections										-
Gas Street overcollection										-
Prior Period Pool under/overcollection		188,463	292,737	354,741	365,582	516,269	526,492	545,015	-	
C Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	-	(1,472,506)
D Net balance to be recovered (A-B+C)	188,463	292,737	354,741	365,582	516,269	526,492	545,015	642,206	16,289	658,495
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	-	(642,206)
Surcharge calculation 2007/2008										
Unrecovered costs (D+E)	-	-	-	-	-	-		-	16,289	16,289
remaining life	-	-	12	24	36	48	60	72	84	
one year	-	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	2,327	
Required annual increase in rates 2007/200 smaller of D or F	-	-	-	-	-	-		-	2,327	2,327
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000132

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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	Dover							Keene						
	(9/02 - 9/03) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #4	(9/08 - 9/09) pool #5	subtotal	(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	subtotal
Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	21,142	-						-
Remediation costs (i.o. 500005)	181,066						181,066	10,165	6,606	35,111	8,766	32	269	60,949
A Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	202,208	10,165	6,606	35,111	8,766	32	269	60,949
														-
Cash recoveries (i.o. 500061)	-					-	-	-						-
Cash recoveries (i.o. 500004)	-						-	-						-
Recovery costs (i.o. 500004)	-						-			18,831	823	-	-	19,655
Transfer Credit from Gas Restructuring							-				-	-	-	-
B Subtotal - net recoveries	-	-	-	-	-	-	-	-		18,831	823	-	-	19,655
A-B Total net expenses to recover	181,066	18,854	2,288	-	-	-	202,208	10,165	6,606	53,942	9,589	32	269	80,604
														-
														-
Surcharge revenue:														-
actual June 1998 - October 1998	-						-	-						-
actual November 1998 - October 1999	-						-	-						-
actual November 1999 - October 2000	-						-	-						-
actual November 2000 - October 2001	-						-	-						-
actual November 2001 - October 2002	-						-	-						-
actual November 2002 - October 2003	-						-	-						-
actual November 2003 - October 2004	(29,134)						(29,134)	-						-
Actual November 2004- October 2005	(28,359)						(28,359)	-	-				-	-
Actual November 2005- October 2006	(27,499)	-			-	-	(27,499)	-	-				-	-
Actual November 2006- October 2007	(28,181)	-	-				(28,181)	-	-	(14,091)				(14,091)
Actual November 2007- October 2008							-							-
AES collections							-							-
Gas Street overcollection							-							-
Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-			10,165	16,771	56,622	66,211	-	
C Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	(113,174)	-	10,165	2,680	56,622	66,211	-	(14,091)
D Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	89,034	10,165	16,771	56,622	66,211	66,244	269	66,513
														-
E Allocation of Litigated Recovery		-		-	(89,034)	-	(89,034)	-	-	-	-	(66,244)	-	(66,244)
														-
Surcharge calculation 2007/2008														-
Unrecovered costs (D+E)	-	-	-		-	-	-	-	-	-			269	269
remaining life	24	36	48	60	72	84		24	36	48	60	72	84	
one year	12	12	12	12	12	12		12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-		-	-	-	-	-	38	
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-		-	-	-	-	-	-			38	38
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000133

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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		Concord						
		(9/03 - 9/04) pool #1	**(9/04 - 9/05) pool #2**	Corrected per 1/24/07 Audit **(9/05 - 9/06) pool #3**	Corrected per 2/08 Audit **(9/06 - 9/07) pool #4**	**(9/07 - 9/08) pool #5**	**(9/08 - 9/09) pool #6**	**subtotal**
	Remediation costs (i.o. 500061)	-						-
	Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	77,063	482,178
A	Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	77,063	482,178
								-
	Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(66,194)
	Cash recoveries (i.o. 500004)	-						-
	Recovery costs (i.o. 500004)					1,432	(1,007)	425
	Transfer Credit from Gas Restructuring			-				-
B	Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	15,616	(65,768)
A-B	Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	92,679	416,410
								-
								-
	Surcharge revenue:							-
actual	June 1998 - October 1998	-						-
actual	November 1998 - October 1999	-						-
actual	November 1999 - October 2000	-						-
actual	November 2000 - October 2001	-						-
actual	November 2001 - October 2002	-						-
actual	November 2002 - October 2003	-						-
actual	November 2003 - October 2004	-						-
Actual	November 2004- October 2005							-
Actual	November 2005- October 2006	-	(27,499)			-	-	(27,499)
Actual	November 2006- October 2007	-	(28,181)	-				(28,181)
Actual	November 2007- October 2008							-
	AES collections							-
	Gas Street overcollection							-
	Prior Period Pool under/overcollection		22,191	187,442	209,549	271,214	-	
C	Surcharge Subtotal	-	(33,490)	187,442	209,549	271,214	-	(55,681)
D	Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	360,730
								-
E	Allocation of Litigated Recovery	-	-	-	-	(268,051)	-	(268,051)
								-
	Surcharge calculation 2007/2008							-
	Unrecovered costs (D+E)	-	-	-		-	92,679	92,679
	remaining life	36	48	60		72	84	
	one year	12	12	12		12	12	
F	amortization 2007/2008	-	-	-		-	13,240	
	Required annual increase in rates 2007/200							
	smaller of D or F	-	-	-		-	13,240	13,240
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000134

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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	General								
	(9/02 - 9/03) pool #1	**(9/03 - 9/04) pool #2**	**(9/04 - 9/05) pool #3**	Corrected per 1/24/07 Audit **(9/05 - 9/06) pool #4**	**(9/06 - 9/07) pool #5**	**(9/07 - 9/08) pool #6**	**(9/08 - 9/09) pool #7**	**subtotal**	**2009 MGP Remediation subtotal**
Remediation costs (i.o. 500061)	-							-	15,026,919
Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	598,727	14,642,849
A Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	598,727	29,669,768
Cash recoveries (i.o. 500061)	-				-	-	-	-	(4,143,226)
Cash recoveries (i.o. 500004)	-							-	(445,985)
Recovery costs (i.o. 500004)				290,155	31,826	16,012	23,953	361,946	2,302,441
Transfer Credit from Gas Restructuring	(3,331)			-				(3,331)	(3,331)
B Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	23,953	358,615	(2,290,101)
A-B Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	(2,931)	957,342	27,379,667
									27,379,667
									-
Surcharge revenue:									
actual June 1998 - October 1998	-	-						-	(54,889)
actual November 1998 - October 1999	-	-						-	(538,143)
actual November 1999 - October 2000	-	-						-	(912,804)
actual November 2000 - October 2001	-	-						-	(1,336,776)
actual November 2001 - October 2002	-	-						-	(1,679,228)
actual November 2002 - October 2003	-	-						-	(1,732,442)
actual November 2003 - October 2004	(8,265)	-						(8,265)	(1,428,735)
Actual November 2004- October 2005		(70,898)						(70,898)	(1,403,787)
Actual November 2005- October 2006		(68,748)	(27,499)			-	-	(96,247)	(1,694,877)
Actual November 2006- October 2007		(77,499)	(28,181)	(49,318)				(154,998)	(2,141,793)
Actual November 2007- October 2008								-	-
AES collections		-						-	(94,876)
Gas Street overcollection								-	(23,511)
Prior Period Pool under/overcollection		(8,388)	313,370	465,817	741,010	794,853	-	-	
C Surcharge Subtotal	(8,265)	(225,533)	257,689	416,499	741,010	794,853	-	(330,408)	(13,041,861)
D Net balance to be recovered (A-B+C)	(8,388)	313,370	465,817	741,010	794,853	629,865	(2,931)	626,934	14,337,806
E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	-	(629,865)	(13,192,066)
Surcharge calculation 2007/2008									
Unrecovered costs (D+E)	-	-	-	-		-	(2,931)	(2,931)	
remaining life		36	48	60	72	84	84		
one year		12	12	12	12	12	12		
F amortization 2007/2008		-	-	-	-	-	(419)		
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-		-	-	-	1,145,739
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	**155,445,404**
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	**$0.0074**

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

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filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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Cash Recoveries[1]

		(9/08 - 9/09) Concord Pond	(9/07 - 9/08) Concord Pond	(9/06 - 9/07) Concord Pond	(9/05 - 9/06) Concord Pond	(9/04- 9/05) Concord Pond	(9/03 - 9/04) Concord Pond	(9/08 - 9/09) Laconia	(9/07 - 9/08) Laconia	(9/06 - 9/07) Laconia	Corrected per 1/24/07 Audit (9/05 - 9/06) Laconia	(9/04 - 9/05) Laconia	(9/03 - 9/04) Laconia
	Remediation costs (i.o. 500061)	-	-		-	-	-	-	-			-	-
	Remediation costs (i.o. 500005)	-	-		-	-	-	-	-			-	-
A	Subtotal - remediation costs	-	-		-	-	-	-	-			-	-
	Cash recoveries (i.o. 500061)												
	Cash recoveries (i.o. 500004)	-	568	-	-	-	(648,000)	-	-	-	-	(23,619)	(2,677,000)
	Recovery costs (i.o. 500004)	-	-	-	73	-	658,508	-	-	45	22,240	486,894	1,492,967
	Transfer Credit from Gas Restructuring	-	-	-	-	-	-						
B	Subtotal - net recoveries	-	568	-	73	-	10,508	-	-	45	22,240	463,275	(1,184,033)
A-B	Total net expenses to recover	-	568	-	73	-	10,508	-	-	45	22,240	463,275	(1,184,033)
	Surcharge revenue:												
actual	June 1998 - October 1998	-	-		-	-	-						
actual	November 1998 - October 1999	-	-		-	-	-						
actual	November 1999 - October 2000	-	-		-	-	-						
actual	November 2000 - October 2001	-	-		-	-	-						
actual	November 2001 - October 2002	-	-		-	-	-						
actual	November 2002 - October 2003	-	-		-	-	-						
actual	November 2003 - October 2004	-	-		-	-	-						
Actual	November 2004- October 2005												
Actual	November 2005- October 2006												
Actual	November 2006- October 2007												
Actual	November 2007- October 2008												
	AES collections	-	-		-	-	-						
	Gas Street overcollection	-	-		-	-	-						
	Prior Period Pool under/overcollection												
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	-	568	-	73	-	10,508	-	-	45	22,240	463,275	(1,184,033)
E	Allocation of Litigated Recovery												
	Surcharge calculation 2007/2008												
	Unrecovered costs (D+E)												
	remaining life												
	one year												
F	amortization 2007/2008												
	Required annual increase in rates 2007/2008												
	smaller of D or F												
	forecasted therm sales												
	surcharge per therm												

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					Corrected per 1/24/07 Audit								
		(9/08 - 9/09) Manchester	**(9/07 - 9/08) Manchester**	**(9/06 - 9/07) Manchester**	**(9/05 - 9/06) Manchester**	**(9/04 - 9/05) Manchester**	**(9/03 - 9/04) Manchester**	**(9/08 - 9/09) Nashua**	**(9/07 - 9/08) Nashua**	**(9/06 - 9/07) Nashua**	**(9/05 - 9/06) Nashua**	**(9/04 - 9/05) Nashua**	**(9/03 - 9/04) Nashua**
	Remediation costs (i.o. 500061)							-	-			-	
	Remediation costs (i.o. 500005)							-	-			-	
A	Subtotal - remediation costs							-	-			-	
	Cash recoveries (i.o. 500061)												
	Cash recoveries (i.o. 500004)	9,679	-	(630,000)	(1,725,792)	(754,938)	-		(1,032,186)	(544,402)	(625,000)	(782,450)	(795,000)
	Recovery costs (i.o. 500004)	(2,008,365)	77,222	195,929	941,433	307,062	951,425		561,030	78,298	645,302	537,552	655,683
	Transfer Credit from Gas Restructuring												
B	Subtotal - net recoveries	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
A-B	Total net expenses to recover	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
	Surcharge revenue:												
actual	June 1998 - October 1998	-	-		-	-							
actual	November 1998 - October 1999	-	-	-	-	-							
actual	November 1999 - October 2000	-	-	-	-	-							
actual	November 2000 - October 2001	-	-	-	-	-							
actual	November 2001 - October 2002	-	-	-	-	-							
actual	November 2002 - October 2003	-	-	-	-	-							
actual	November 2003 - October 2004	-	-	-	-	-							
Actual	November 2004- October 2005												
Actual	November 2005- October 2006				-	-							
Actual	November 2006- October 2007												
Actual	November 2007- October 2008												
	AES collections	-	-	-									
	Gas Street overcollection	-	-	-									
	Prior Period Pool under/overcollection				-	-							
					-	-							
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
E	Allocation of Litigated Recovery												
	Surcharge calculation 2007/2008												
	Unrecovered costs (D+E)												
	remaining life												
	one year												
F	amortization 2007/2008												
	Required annual increase in rates 2007/2008												
	smaller of D or F												
	forecasted therm sales												
	surcharge per therm												

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		(9/08 - 9/09) Dover	(9/07 - 9/08) Dover	(9/06 - 9/07) Dover	(9/05 - 9/06) Dover	(9/04 - 9/05) Dover	(9/03 - 9/04) Dover	(9/08 - 9/09) Keene	(9/07 - 9/08) Keene	(9/06 - 9/07) Keene	(9/05 - 9/06) Keene	(9/04 - 9/05) Keene	(9/03 - 9/04) Keene	(9/06 - 9/07) General	2009 subtotal	2009 MGP TOTAL
	Remediation costs (i.o. 500061)	-	-		-	-					-	-			-	15,026,919
	Remediation costs (i.o. 500005)	-	-		-	-					-	-			-	14,642,849
A	Subtotal - remediation costs	-	-		-	-					-	-			-	29,669,768
	Cash recoveries (i.o. 500061)														-	(4,143,226)
	Cash recoveries (i.o. 500004)	-	(2,133)	-	(237,489)	(7,150)	(645,500)	116			(700,000)	(211,213)	0	(10,760,900)	(22,792,408)	(23,238,393)
	Recovery costs (i.o. 500004)	(92,947)	-	14,848	117,621	517,891	500,868		1,559	28,211	309,618	56,392	121,018		7,178,376	9,480,817
	Transfer Credit from Gas Restructuring														-	(3,331)
B	Subtotal - net recoveries	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(4,853,133)	(7,143,234)
															-	-
A-B	Total net expenses to recover	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	11,765,635
	Surcharge revenue:															
actual	June 1998 - October 1998														-	(54,889)
actual	November 1998 - October 1999														-	(538,143)
actual	November 1999 - October 2000														-	(912,804)
actual	November 2000 - October 2001														-	(1,336,776)
actual	November 2001 - October 2002														-	(1,679,228)
actual	November 2002 - October 2003														-	(1,732,442)
actual	November 2003 - October 2004														-	(1,428,735)
Actual	November 2004- October 2005														-	(1,403,787)
Actual	November 2005- October 2006															(1,694,877)
Actual	November 2006- October 2007															(2,141,793)
Actual	November 2007- October 2008															-
	AES collections														-	(94,876)
	Gas Street overcollection														-	(23,511)
	Prior Period Pool under/overcollection														-	
															-	
C	Surcharge Subtotal	-	-	-	-	-	-			-	-	-	-		-	(13,041,861)
															-	
															-	
D	Net balance to be recovered (A-B+C)	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	(1,276,227)
																1,208,288
E	Allocation of Litigated Recovery														13,192,066	
															(2,421,966)	
	Surcharge calculation 2007/2008															
	Unrecovered costs (D+E)															
	remaining life															
	one year															
F	amortization 2007/2008															
	Required annual increase in rates 2007/2008															
	smaller of D or F															
	forecasted therm sales															
	surcharge per therm															

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filed under the following protective orders:
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EnergyNorth Natural Gas, Inc.
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Expense and Collection Summary per Year

	(thru 3/98)	(4/98 - 9/98)	10/98 - 9/15/99	(9/99 - 9/00)	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	Total
Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	15,026,919
Remediation costs (i.o. 500005)	-	-	1,027,747	3,513,285	2,428,832	362,663	689,437	571,259	445,367	2,444,366	2,229,625	255,263	675,005	14,642,849
A Subtotal - remediation costs	1,422,811	1,843,806	3,181,982	3,642,287	2,428,832	362,663	689,437	977,731	2,682,050	3,442,003	2,956,367	4,845,887	1,193,912	29,669,768
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(4,143,226)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	(23,238,393)
Recovery costs (i.o. 500004)	623,784	-	-	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	9,480,817
Transfer Credit from Gas Restructuring	-	-	-	-	-	-	(3,331)	-	-	-	-	-	-	(3,331)
B Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(3,331)	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(17,904,133)
A-B Total net expenses to recover	520,030	1,409,330	2,682,299	3,609,083	2,428,832	362,663	686,106	1,835,026	2,808,471	1,903,772	(8,887,756)	3,340,669	(932,890)	11,765,635
Surcharge revenue:														
actual June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
actual November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	-	-	(538,143)
actual November 1999 - October 2000	(178,131)	(266,400)	(468,273)	-	-	-	-	-	-	-	-	-	-	(912,804)
actual November 2000 - October 2001	-	(292,420)	(487,366)	(556,990)	-	-	-	-	-	-	-	-	-	(1,336,776)
actual November 2001 - October 2002	-	(281,914)	(478,029)	(551,571)	(367,714)	-	-	-	-	-	-	-	-	(1,679,228)
actual November 2002 - October 2003	-	(258,347)	(486,300)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	-	(1,732,442)
actual November 2003 - October 2004	-	(14,567)	(407,875)	(480,710)	(349,608)	(43,701)	(132,274)	-	-	-	-	-	-	(1,428,735)
Actual November 2004- October 2005	-	-	(184,336)	(453,749)	(326,132)	(42,539)	(99,258)	(297,773)	-	-	-	-	-	(1,403,787)
Actual November 2005- October 2006	-	-	(141,176)	(460,610)	(316,240)	(54,998)	(96,247)	(281,866)	(343,739)	-	-	-	-	(1,694,877)
Actual November 2006- October 2007	-	-	-	(549,539)	(338,178)	(56,363)	(112,726)	(288,860)	(366,359)	(429,768)	-	-	-	(2,141,793)
Actual November 2007- October 2008														
AES collections	-	-	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(12,888)	(94,876)
Gas Street overcollection	-	(23,511)	-	-	-	-	-	-	-	-	-	-	-	(23,511)
Prior Period Pool under/overcollection														
C Surcharge Subtotal	(520,030)	(1,388,292)	(2,653,355)	(3,615,454)	(2,062,596)	(258,389)	(440,504)	(902,092)	(721,725)	(441,669)	(12,271)	(12,597)	(12,888)	(13,041,861)
D Net balance to be recovered (A-B+C)	-	21,038	28,944	(6,371)	366,236	104,274	245,602	932,934	2,086,746	1,462,103	(8,900,027)	3,328,072	(945,778)	(1,276,227)
E Allocation of Litigated Recovery														

Surcharge calculation 2007/2008
Unrecovered costs (D+E)
remaining life
one year
F amortization 2007/2008

Required annual increase in rates 2007/2008
smaller of D or F

forecasted therm sales

surcharge per therm

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00000139

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

CONCORD FORMER MGP

LINE
NO.

1. SITE LOCATION: One Gas Street, Concord, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: EnergyNorth Natural Gas, Inc. (ENGI) received a Notice Letter from the New Hampshire Department of Environmental Services (NHDES) in September, 1992. The Notice related primarily to contamination identified in the pond adjacent to Exit 13 off Interstate 93, although it was broad enough to also include the former manufactured gas plant (MGP) site itself.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond, as the NHDOT began site preparation work for the reconfiguration of that interchange. Subsequent investigations by ENGI and others indicate that contaminants originating from the MGP on Gas Street are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI has continued to monitor groundwater semiannually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003 and 2007, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit. These sample results will be evaluated over time to address the efficacy of the existing remedy, and determine if additional treatment may be necessary.

   The New Hampshire Department of Transportation (NHDOT) contacted ENGI in August 2001 and February 2002 regarding possible coal tar-related impacts in a sewer line on a parcel adjacent to the former gas plant. NHDOT is currently conducting groundwater monitoring as part of a Groundwater Management Zone Permit on this parcel. ENGI met with NHDOT and NHDES in January 2003 to review the results of its 2002 site investigation. Limited coal tar impacts were observed in groundwater and subsurface soils at select locations.

   On July 15, 2003, NHDES issued a letter to KeySpan requesting submission of a schedule and scope of work for a site investigation of the gas plant by mid-September 2003. ENGI proposed a May 2005 date for submission of a site investigation report for the former manufactured gas plant on Gas Street to NHDES by way of a letter dated

October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report is currently being finalized. ENGI will meet with NHDES to discuss the report findings and strategy for moving forward when the final report is submitted to NHDES.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project has moved into the remedial design phase. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is currently drafting an agreement to clarify the responsibilities of the three parties.

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond. In May 2007, NHDES approved ENGI's April 2007 scope of work to conduct additional investigations around this well to determine the extent of the coal tar impacts and the feasibility of removing it from the subsurface. The issues associated with this well will be included in the overall site strategy.

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. The sediment sampling data report summarizing the results of the investigation is currently being drafted. ENGI will meet with NHDES to discuss the report findings and strategy for moving forward when the final report is submitted to NHDES.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI is undertaking a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design will be completed pending an agreement between the City, NHDOT and ENGI.

In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the gas plant. ENGI submitted the scope to NHDES in May 2004, and implemented it between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Concord MGP operated from approximately 1850 to 1952, when the natural gas pipeline was extended to Concord. The plant was constructed and operated by predecessors of the Concord Gas Company, which later became known as the Concord Natural Gas Company. By virtue of a merger, ENGI acquired Concord Natural Gas. As has been reported previously by ENGI, it filed a contribution claim in the United States District Court for the District of New Hampshire against the successor to the United Gas Improvement Company. In that claim, ENGI alleged that under the federal Superfund statute, the United Gas Improvement Company exercised control over the operations of the Concord Gas Plant to the extent that the United Gas Improvement Company should be considered an "operator" under the statute. That matter was settled in 1997.

CONCORD FORMER MGP

LINE
NO.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Numerous confidential settlements with insurance carriers and with one private party have been entered into*. Insurance recovery efforts at the Concord Site are complete.*

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
KEYSPAN PROJECT DEF056

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Anchor Environmental	15096	1,926.50			1,926.50
2	Anchor Environmental	15328	9,954.70			9,954.70
3	Anchor Environmental	16007	16,218.88			16,218.88
4	Anchor Environmental	16156	7,079.56			7,079.56
5	Anchor Environmental	17066	5,159.16			5,159.16
6	Anchor Environmental	17262	2,936.50			2,936.50
7	Anchor Environmental	17704	3,614.55			3,614.55
8	Anchor Environmental	16534	8,404.68			8,404.68
9	Anchor Environmental	18050	22,079.00			22,079.00
10	Clean Harbors	NH0878735	2,592.86			2,592.86
11	Clean Harbors	SB0973817	1,832.93			1,832.93
12	Environmental Staff Payroll	Spreadsheet	2,264.23			2,264.23
13	GEI Consultants	47864	1,651.05			1,651.05
14	GEI Consultants	48098	2,271.03			2,271.03
15	GEI Consultants	47519	3,605.14			3,605.14
16	GEI Consultants	47789	6,335.09			6,335.09
17	GEI Consultants	48218	1,981.09			1,981.09
18	GEI Consultants	48415	1,890.01			1,890.01
19	GEI Consultants	48559	2,554.06			2,554.06
20	GEI Consultants	48920	3,519.07			3,519.07
21	GEI Consultants	48763	5,314.17			5,314.17
22	GEI Consultants	49139	690.26			690.26
23	GEI Consultants	49045	1,238.09			1,238.09
24	GEI Consultants	49351	1,406.75			1,406.75
25	GEI Consultants	49420	7,403.00			7,403.00
26	GZA Geoenvironmental	605551	2,346.04			2,346.04
27	GZA Geoenvironmental	604230	897.00			897.00
28	New Hampshire Department of Environmental Services	199212014-06	289.70			289.70
29	New Hampshire Department of Environmental Services	199212014-07	731.86			731.86
30						
31						
32						
33						
34	**Total Pool Activity**		**128,186.96**	**-**	**(12,607.76)**	**115,579.20**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
KEYSPAN PROJECT DEF077

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Clean Harbors	SB0897952	846.09			846.09
2	Clean Harbors	SB1913771	881.25			881.25
3	Environmental Staff Payroll	Spreadsheet	67.30			67.30
4	GZA Geoenvironmental	606448	19,752.32			19,752.32
5	GZA Geoenvironmental	610249	54,794.18			54,794.18
6						
7	McLane	2008110418	-	204.00		204.00
8	McLane	2008120991	-	417.00		417.00
9	McLane	2009010165	-	3,168.14		3,168.14
10	McLane	2009030646	-	1,864.00		1,864.00
11	McLane	2009040510	-	3,486.00		3,486.00
12	McLane	2009030633	-	5,390.00		5,390.00
13	McLane	2009050928	-	1,060.20		1,060.20
14	McLane	2009070321	-	513.00		513.00
15	McLane	2009060683	-	520.60		520.60
16	New Hampshire Department of Environmental Services	198904063-03	721.44			721.44
17			-			-
18	**Total Pool Activity**		**77,062.58**	**16,622.94**	**(1,006.53)**	**92,678.99**

00000145

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD - LITIGATION
KEYSPAN PROJECT DEF051

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1			-			-
2			-			-
3	**NO ACTIVITY FOR THIS PERIOD**					
4			-	-		-
5	**Total Pool Activity**		**-**	**-**	**-**	**-**

000000146

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.

2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI), another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Winnipesaukee River. The full nature and extent of contamination is unknown at this time. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials from the former MGP were disposed of at the Liberty Hill disposal area, and MGP-related constituents have been detected in soil and ground water.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: Based on the settlement with PSNH that has previously been reported to the Commission, ENGI has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area. Please contact PSNH and refer to PSNH filings with NHDES for complete information on material developments and interactions with environmental authorities.

With respect to the Liberty Hill disposal area, in October 2004, ENGI notified NHDES of the possible existence of this disposal site; the site was assigned disposal site number 200411113 by NHDES. NHDES collected drinking water samples from two residential wells in the vicinity in December 2004 and from three additional residential wells in June and July 2005; no MGP-related contaminants were detected. In January 2005, NHDES requested that ENGI conduct a preliminary site investigation on the two residential properties. ENGI submitted a scope of work for the investigation to NHDES on March 2, 2005. The investigation began in July 2005 and was completed in June 2006 with the submission of the Site Investigation Report.

Additional site investigations were conducted in 2006 and summarized in the December 20, 2006 Interim Data Report #2 submitted to NHDES. Based upon the results of the investigations, remediation is required at the site. In response, a Remedial Action Plan (RAP) was submitted to NHDES on February 28, 2007. The RAP presented NHDES with several remedial alternatives to address soil and groundwater contamination at the site. The February 2007 RAP identified soil excavation (to a depth of 3 feet), construction of a containment wall and impermeable cap on the four residential properties purchased by ENGI as the recommended alternative. In September 2007, NHDES responded to the February 2007 RAP and required that ENGI evaluate additional remedial alternatives that included further soil removal. In November 2007, a RAP Addendum was submitted to NHDES. The revised RAP recommended a remedial alternative that included removal of tar-saturated soils to a depth of approximately 45 feet, construction of a containment wall and impermeable cap on the four residential properties owned by ENGI. On February 29, 2008, NHDES issued a letter to ENGI indicating that NHDES had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modeling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI is currently preparing the second RAP Addendum and anticipates submitting the document to NHDES in mid-August.

ENGI has also performed numerous other activities requested by NHDES in 2008 and 2009, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan;, evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; and semi-annual groundwater and surface water sampling activities. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

In conjunction with the Site Investigation work, ENGI has acquired 4 properties on Liberty Hill Road to facilitate remediation activities, and eliminate any potential risk to residents associated with a significant remediation and construction project. The properties were obtained based upon arms-length negotiations, and in one instance to settle potential litigation.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Please refer to Item 4.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc. (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Laconia MGP, which began operating in 1894, was included in that transaction. Gas manufacturing took place at the property until 1952, when the MGP was

converted to propane. Half of the property is now owned by Robert Irwin and maintained as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

The Liberty Hill Road parcel on which disposal was believed to have occurred was utilized as a gravel pit at the time of the disposal. It was subdivided in May 1970, and currently constitutes part of a residential subdivision.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003 the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May, 2004 the Supreme Court responded that a “continuous injury-in-fact” trigger should be applied. The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.
With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF086

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Blue Chip Films	795	1,575.00			1,575.00
2	Blue Chip Films	798	450.00			450.00
3	Blue Chip Films	847	725.00			725.00
4	Blue Chip Films	853	725.00			725.00
5	Blue Chip Films	836	3,625.00			3,625.00
6	Clean Harbors	SB0825020	778.88			778.88
7	Clean Harbors	SB0897949	962.26			962.26
8	Clean Harbors	SB0916643	6,153.65			6,153.65
9	Environmental Staff Payroll	Spreadsheet	738.65			738.65
10	GEI Consultants	49419	34,797.24			34,797.24
11	GEI Consultants	47788	4,338.75			4,338.75
12	GEI Consultants	47863	6,947.89			6,947.89
13	GEI Consultants	47518	12,342.35			12,342.35
14	GEI Consultants	48097	53,633.27			53,633.27
15	GEI Consultants	48421	23,978.00			23,978.00
16	GEI Consultants	48217	28,464.30			28,464.30
17	GEI Consultants	48558	20,828.99			20,828.99
18	GEI Consultants	48919	100,647.39			100,647.39
19	GEI Consultants	48762	150,315.47			150,315.47
20	GEI Consultants	49138	35,644.85			35,644.85
21	GEI Consultants	49029	47,986.69			47,986.69
22	GEI Consultants	49350	18,628.63			18,628.63
23	McLane	2008071223	680.03			680.03
24	McLane	2008080247	22,142.72			22,142.72
25	McLane	2008090239	9,191.14			9,191.14
26	McLane	2009010164	170.00			170.00
27	McLane	2009030653	525.10			525.10
28	McLane	2009030632	1,676.30			1,676.30
29	McLane	2009040509	3,573.04			3,573.04
30	McLane	2009050930	2,419.70			2,419.70
31	McLane	2009060885	3,066.60			3,066.60
32	New Hampshire Department of Environmental Services	200411113-04	8,050.81			8,050.81
33	New Hampshire Department of Environmental Services	200411113-05	9,924.97			9,924.97
34	Ostrow & Partners	100801	310.00			310.00
35	Ostrow & Partners	90801	1,605.00			1,605.00
36	Ostrow & Partners	80803	2,130.00			2,130.00
37	Ostrow & Partners	110801	2,359.00			2,359.00
38	Ostrow & Partners	120801	545.00			545.00
39	Ostrow & Partners	20901	320.00			320.00
40	Ostrow & Partners	30901	320.00			320.00
41	Ostrow & Partners	50901	385.00			385.00
42	Ostrow & Partners	60901	610.00			610.00
43	Public Service of New Hampshire	5062009	8.93			8.93
44	Public Service of New Hampshire	8062008	17.35			17.35
45	Public Service of New Hampshire	9092008	17.43			17.43
46	Public Service of New Hampshire	11062008	0.68			0.68
47	Public Service of New Hampshire	11122008	12.36			12.36
48	Public Service of New Hampshire	12082008	8.93			8.93
49	Public Service of New Hampshire	12082008	9.98			9.98
50	Public Service of New Hampshire	1072009	17.95			17.95
51	Public Service of New Hampshire	1142009	43.79			43.79
52	Public Service of New Hampshire	2232009	8.93			8.93
53	Public Service of New Hampshire	2092009	81.36			81.36
54	Public Service of New Hampshire	4072009	9.02			9.02
55	Public Service of New Hampshire	3092009	10.46			10.46
56	Public Service of New Hampshire	3062009	9.02			9.02
57	Public Service of New Hampshire	7092008	8.93			8.93
58						-
59	**Total Pool Activity**		**624,556.79**	**-**	**-**	**624,556.79**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF087

LINE NO.	VENDOR	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1		-			-
2		-			-
3	**NO ACTIVITY FOR THIS PERIOD**				-
4		-			-
5	**Total Pool Activity**	**-**	**-**	**-**	**-**

00000152

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LACONIA - LITIGATION
KEYSPAN PROJECT DEF050

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1			-			-
2			-			-
3	**NO ACTIVITY FOR THIS PERIOD**					
4			-	-		-
5	**Total Pool Activity**		**-**	**-**	**-**	**-**

00000153

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

LINE
NO.

1. SITE LOCATION: 130 Elm Street, Manchester, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: The New Hampshire Department of Environmental Services (NHDES) compiled a list of all former Manufactured Gas Plants (MGPs) in New Hampshire that were not already subject to a site investigation or remediation. In March of 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites. EnergyNorth Natural Gas, Inc. (ENGI) received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP from NHDES, which designated the site DES #200003011. It is understood that NHDES intended to solicit site investigation reports on all MGPs and then prioritize them for remedial action.

3. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - On behalf of ENGI, Harding ESE, Inc. (Harding ESE), submitted a Scoping Phase Field Investigation Scope of Work to NHDES in March 2000.

   - NHDES approved the Scoping Phase Field Investigation Scope of Work in June 2000.

   - During the summer and fall of 2000, ENGI and Harding ESE conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Manchester MGP and the nearby Merrimack River.

   - On August 31, 2000 an underground tank containing MGP residuals was discovered at the site. As required by NHDES regulations, the tank contents were removed and disposed of subject to a permit from NHDES. Harding ESE submitted a summary report to NHDES in January 2001 on behalf of ENGI documenting the response action.

   - ENGI and Harding ESE submitted the Scoping Phase Field Investigation Report to NHDES in February 2001.

   - NHDES provided comments to ENGI and Harding ESE in April 2001 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

   - ENGI responded to NHDES' comments on the Scoping Phase Investigation Report and indicated that ENGI planned to solicit bids for the Phase II Scope of Work.

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments.

- In October 2001, NHDES accepted ENGI’s fence installation plan, but requested clarification on the fence location and signage.

- In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence.

- NHDES approved the ravine sign language in April 2002.

- On May 1, 2002, ENGI issued a Request for Proposals to eight environmental consultants for the Phase II Site Investigation and Risk Characterization.

- ENGI received six proposals for the Phase II work in June 2002.

- In June 2002, the City of Manchester approved the ravine fence location and granted access to City property to install. The work was completed in August 2002.

- URS Consultants were awarded the contract to undertake the next phase of work. A Phase II Site Investigation Scope of Work was submitted in September 2002.

- Phase II field investigations began in the fall of 2002.

- In June 2003, the City of Manchester approved a proposal to construct a minor league ballpark, retail shops, parking garage, hotel and high-rise condominium complex on the Singer Park site, in the same general areas that MGP impacts were detected in ongoing Phase II investigations. Following supplemental ravine investigations during the spring and summer of 2003, the Drainage Ravine Engineering Evaluation was submitted to NHDES in January 2004, and presented four potential remedial alternatives for the ravine, which is located on a portion of Singer Park.

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers since April 2003, until they ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment are being addressed concurrently and that ENGI avoids incurring costs associated with another entity's contamination.

- ENGI entered into confidential agreements with Manchester Parkside Place (the owner of the ravine property) for access and cleanup of MGP byproducts in the ravine in January 2005.

- In January 2005, ENGI submitted a Remedial Design Report to NHDES selecting excavation and off-site disposal of source material and impacted soils as the remedial alternative for the ravine. NHDES approved of this alternative via a letter dated February 7, 2005. Eleven contractors were invited to bid on the ravine remediation in January 2005. The contract was awarded to the low bidder (ENTACT) in February 2005. Remediation of the ravine began in March and was completed in July 2005. A remedial completion report was submitted to NHDES on September 2, 2005.

- ENGI submitted a Phase II Site Investigation Report to NHDES in March 2004. The report concluded that MGP impacts (including impacted soil and groundwater and separate phase coal tar) were present in the subsurface beneath the 130 Elm Street property, in portions of Singer Park at depth and in the Merrimack River sediment. Further investigations were recommended by ENGI to completely bound the nature and extent of this contamination and a work plan proposing those investigations was submitted to NHDES in May 2004 and approved in July 2004. These supplemental investigations were completed and documented in the Supplemental Phase II Investigation Report and the Stage I Ecological Screening Report for the Merrimack River, submitted to NHDES in February and March 2005, respectively. The reports concluded that a Remedial Action Plan for the upland and Merrimack River is required. On September 15, 2005, NHDES issued a letter accepting the reports and requested ENGI prepare a Remedial Action Plan (RAP) to address impacted sediments in the Merrimack River, as well as MGP-related impacts on the upland portion of the site. Preparation of the RAP began in August 2006.

- Additional Merrimack River investigations were completed in 2007 and the Remedial Design Report for dredging approximately 9,000 cubic yards of coal tar-impacted sediments from the river was submitted to NHDES on May 11, 2007. ENGI applied for, and was granted, a Dredge and Fill Permit for the remedial dredging from NHDES and the United States Army Corps of Engineers on May 18, 2007. Dredging of the river commenced in June 2007 and was substantially completed by the end of the year. Final site restoration activities associated with the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

- Predesign investigations are ongoing on the upland portion of the former MGP site in 2008/2009. In additional, ENGI is currently conducting interim remediation activities at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale coal tar recovery, and design for replacement of a portion of the site drainage system. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedences in shallow soils. Following a review of the data to be collected during the pilot test interim activities, the upland Remedial Action Plan is expected to be completed and submitted to NHDES by June 30, 2010.

- ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the former MGP site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements.

4. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A Remedial Action Plan is currently being developed for the upland portion of the MGP site and is currently scheduled for submittal to NHDES by June 30, 2010.

5. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The former Manchester MGP is believed to have started producing coal gas in 1852. Gas was produced at the site by the Manchester Gas Company and its predecessors until the MGP was shut down in 1952 when natural gas was supplied to the city via pipeline. ENGI is the successor by merger to the Manchester Gas Company. ENGI continues to own and operate the 130 Elm Street property as an operations center.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity “operated” the Manchester Gas Plant, as defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as “CERCLA” or “Superfund”). This claim was similar to a claim

litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier willpaid ENGI's attorneys fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys fees. EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
KEYSPAN PROJECT DEF057

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Anchor Environmental	14459	2,012.50			2,012.50
2	Anchor Environmental	15095	436.25			436.25
3	Anchor Environmental	14768	591.25			591.25
4	Anchor Environmental	15628	1,216.25			1,216.25
5	Anchor Environmental	15315	1,366.57			1,366.57
6	Clean Harbors	NH0811971	337.08			337.08
7	Clean Harbors	NH0823423R	1,815.78			1,815.78
8	Clean Harbors	NH0849708R	4,792.26			4,792.26
9	Clean Harbors	NH0878734	159.00			159.00
10	Clean Harbors	NH0871545	432.10			432.10
11	Clean Harbors	NH0880222	503.50			503.50
12	Clean Harbors	NH0861511R	64,241.41			64,241.41
13	Clean Harbors	NH0880242R	983.68			983.68
14	Clean Harbors	NH0852357	19,115.62			19,115.62
15	EECS Inc.	205	165.00			165.00
16	Environmental Staff Payroll	Spreadsheet	67.30			67.30
17	ESMI	1005540	132.41			132.41
18	ESMI	1005678	17,134.08			17,134.08
19	Haley & Aldrich	692107	1,381.93			1,381.93
20	Haley & Aldrich	685709	6,247.01			6,247.01
21	Haley & Aldrich	670248	627.12			627.12
22	Maxymillian Technologies	8061	34,675.63			34,675.63
23	NH Department of Environmental Services	NHD500012257	12,445.14			12,445.14
24	NH Department of Environmental Services	7062009	16.44			16.44
25	NH Department of Environmental Services	7062009	16.44			16.44
26	NH Department of Environmental Services	7062009	16.44			16.44
27	NH Department of Environmental Services	7062009	16.44			16.44
28	NH Department of Environmental Services	7062009	16.44			16.44
29	URS	3552199	8,827.75			8,827.75
30	URS	3498786	12,706.78			12,706.78
31	URS	3635846	5,668.90			5,668.90
32	URS	3637299	19,994.72			19,994.72
33	URS	3660228	72,376.01			72,376.01
34	URS	3707730	7,570.69			7,570.69
35	URS	3747143	3,140.06			3,140.06
36	URS	3826854	1,067.00			1,067.00
37	URS	3789353	1,957.46			1,957.46
38	URS	3871396	1,024.83			1,024.83
39	URS	3913519	6,890.00			6,890.00
40			-			-
41	**Total Pool Activity**		**312,185.27**	**-**	**-**	**312,185.27**

00000159

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - LITIGATION
KEYSPAN PROJECT DEF058

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	McLane	2007120172	-	665.00		665.00
2	McLane	2005080397	-	324.00		324.00
3	McLane	2008070647	-	2,344.50		2,344.50
4	McLane	2008080397	-	3,200.00		3,200.00
5	McLane	2008110357	-	510.00		510.00
6	McLane	2008121340	-	170.00		170.00
7	McLane	2008090287	-	2,465.62		2,465.62
8	McLane Overpayment		-		(197.00)	(197.00)
9						
10	**Total Pool Activity**		**-**	**9,679.12**	**(2,008,365.12)**	**(1,998,686.00)**

00000160

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

1. SITE LOCATION: 38 Bridge Street, Nashua, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: At the end of 1998, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua manufactured gas plant (MGP) to the former plant owners/operators: EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England (ENGI), and Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities Services Company (NU). NHDES designated the site DES #199810022.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - Prior to the time NHDES issued its notice letter to ENGI, the US Environmental Protection Agency (EPA) was remediating contamination (asbestos) at a former Johns Manville plant located adjacent to, and downstream from the 38 Bridge Street property. In the course of that work, EPA detected what it determined to be MGP related residuals in Nashua River sediments containing asbestos. EPA sought reimbursement from ENGI and PSNH of only those incremental additional costs it incurred to dispose of sediments containing MGP related wastes in addition to asbestos. ENGI and PSNH entered into a settlement agreement with the EPA at the end of September 2000. Under the terms of the agreement, each company received a release from liability associated with the so-called Nashua River Superfund Site and contribution protection against future claims associated with that site. The settlement agreement made it clear that EPA does not contend that ENGI or PSNH contributed any asbestos to the Nashua River.

   - In response to the 1998 notice from NHDES, QST Environmental, Inc. (QST, subsequently Environmental Science and Engineering, Inc. (ESE), and later Harding ESE, Inc. (Harding ESE)), submitted a Scoping Phase Field Investigation Scope of Work to NHDES on behalf of ENGI in February 1999.

   - In response to comments from NHDES, QST and ENGI refined the Scope of Work for the Scoping Phase Field Investigation and resubmitted to NHDES in April 1999.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.

- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.

- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.

- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.

- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.

- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.

- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.

- ENGI and ESE developed a letter discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and from PSNH/NU and submitted the document in August 2000 along with a proposed schedule for implementation.

- NHDES approved the Revised Phase II Work Plan for the 38 Bridge Street Site at the end of August 2000.

- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.

- Harding ESE submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

LINE
NO.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH/NU reached agreement in late 2000 regarding sharing of costs for the remediation work and transfer of management of the remediation work to ENGI.

- Harding ESE implemented the Phase II Work Plan during the fall and winter of 2000-2001. Work entailed a comprehensive field program that included river borings and sediment samples as well as borings and monitoring wells completed on and off the property.

- NHDES provided comments on the Phase II Work Plan addendum in February 2001.

- Harding ESE responded to NHDES comments on the Phase II Work Plan addendum in March 2001.

- In May 2001, ENGI and Harding ESE submitted to NHDES a Draft Site Conceptual Model to assist with finalization of the Phase II Work Plan Addendum and met with NHDES to discuss.

- ENGI and NHDES met in early June 2001 to discuss draft site conceptual model and the overall site objectives and approach.

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June.

- In July 2001, ENGI and Harding ESE met with NHDES to review the Site Conceptual Model and proposed Phase II supplemental investigation activities.

- ENGI and NHDES met in August 2001 to discuss the overall site objectives.

- In September 2001, Harding ESE, on behalf of ENGI, submitted a Phase IIB Supplemental Site Investigation (SI) Scope of Work to NHDES.

- NHDES provided verbal approval for the Phase IIB Supplemental SI, and Harding ESE initiated the field program on behalf of ENGI in October 2001.

- NHDES provided written approval of the Phase IIB Supplemental SI in October 2001. A modification to the proposed scope of work relating to investigations adjacent to the gas lines was made, and verbal approval obtained, on November 19, 2001.

- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.

- ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.

- Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.

- The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.

- ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.

- By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.

- ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application

LINE
NO.

administratively complete. The hearing was closed on July 26, 2004 and the permit was issued in September 2004. The capping and re-armoring was completed in October 2004 and Remedial Completion Report submitted to NHDES in January 2005, and subsequently approved.

- In October 2005, ENGI submitted the Terrestrial Remedial Action Plan to NHDES, and the document was deemed complete by NHDES in March 2006. NHDES requested supplemental information to be submitted before ENGI proceeded with remediation, and in 2007 ENGI gathered that additional data.

- In November 2007, ENGI submitted a Workplan for DNAPL Recovery Pilot Test to NHDES and the document was approved by NHDES on November 14, 2007.

- ENGI applied for three permits required for the implementation of the NHDES-approved DNAPL pilot testing activities: Nashua Conservation Commission Permit, Nashua Zoning Board of Appeals Permit and NHDES Dredge and Fill Permit. ENGI attended numerous hearings related to obtaining the permits and obtained the three permits on April 21, 2008, April 23, 2008 and May 31, 2008, respectively.

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be use to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and 2009 (to date).

- In Spring 2009, ENGI began trenching and final system installation activities. The trenching, pump installations and system electrical work was completed in July 2009. System start-up is pending final electrical hook-up by PSNH. It is anticipated that this work will be completed in August 2009.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the Fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. Pilot testing of the DNAPL recovery system in the approved RAP is on-going.

LINE
NO.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Nashua Gas Light Company built the original coal gas facility in 1852 or 1853. In 1889, the Nashua Gas Light Company merged with the Nashua Electric Company to form the Nashua Light, Heat and Power Company (NHLPC). In 1914, the NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: The EPA made a claim against ENGI and PSNH related to the so-called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA's claim in exchange for a payment of $387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

   ENGI and PSNH have entered into a confidential Site Responsibility and Indemnity Agreement effective as of September 15, 2000, which governs the financial and decision-making responsibilities of the two companies through the remainder of site study and remediation. Under this agreement, ENGI will take the lead on site investigation and remediation.

   Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be paid by the defendants. Subsequent to the verdict, the London Market and ENGI entered into a confidential settlement. Century appealed to the First Circuit Court of Appeals in the summer of 2006. However, on the day its brief was due at the First Circuit, Century withdrew its appeal. Because the site has not yet been remediated, the jury was not asked to make a damage determination. Future proceedings will take place after the remedy has been approved by the NHDES to determine the indemnification amounts to be paid by Century. The New Hampshire Supreme Court's ruling on the allocation issue (discussed in the Manchester MGP summary) will affect that figure.

LINE
NO.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
KEYSPAN PROJECT DEF054

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
1	Clean Harbors	SB0897101	4,229.28			4,229.28
2	Environmental Staff Payroll	Spreadsheet	168.25			168.25
3	Innovative Engineering Solutions, Inc.	6940	2,031.79			2,031.79
4	Innovative Engineering Solutions, Inc.	7069	17,928.18			17,928.18
5	Innovative Engineering Solutions, Inc.	7001	27,389.66			27,389.66
6	Innovative Engineering Solutions, Inc.	7586	1,755.15			1,755.15
7	Innovative Engineering Solutions, Inc.	7521	5,540.31			5,540.31
8	Innovative Engineering Solutions, Inc.	7229	1,658.31			1,658.31
9	Innovative Engineering Solutions, Inc.	7146	2,504.38			2,504.38
10	Innovative Engineering Solutions, Inc.	7256	6,592.85			6,592.85
11	Innovative Engineering Solutions, Inc.	7441	1,004.42			1,004.42
12	Innovative Engineering Solutions, Inc.	7359	2,286.66			2,286.66
13	Innovative Engineering Solutions, Inc.	7637	248.58			248.58
14	Innovative Engineering Solutions, Inc.	7637	4,774.27			4,774.27
15	New Hampshire Department of Environmental Services	NHD500012216	249.00			249.00
16	New Hampshire Department of Environmental Services	199810022-05	173.82			173.82
17						
18						
19			-			-
20	**Total Pool Activity**		**78,534.91**	**-**	**(62,246.06)**	**16,288.85**

00000168

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - LITIGATION
KEYSPAN PROJECT DEF049

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
1			-			-
2			-			-
3	**NO ACTIVITY FOR THIS PERIOD**					
4						-
5	**Total Pool Activity**		**-**	**-**	**-**	**-**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

DOVER FORMER MGP

LINE
NO.

1. SITE LOCATION: Intersection of Cocheco Street and Portland Street, Dover, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: In 1999, NHDES sent notice letters to current and former site owners and operators including: Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities (NU).; EnergyNorth Natural Gas, Inc. (ENGI); Northern Utilities, Inc.; and Central Vermont Public Service Company (CVPS). It is the company's understanding that NHDES sent a notice to the current site owner, Estelle Maglaras, earlier. NHDES designated the site DES #198401047.

3. NATURE AND SCOPE OF SITE CONTAMINATION: According to the August 2002 Supplemental Site Investigation Report, the evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - During late 1999 and early 2000, PSNH/NU took the lead on preparation of a Site Investigation Report. PSNH/NU submitted the report to NHDES and the other potentially responsible parties (PRPs) in February 2000.

   - The PRPs held meetings and discussions during 2000 regarding site responsibility and liability.

   - Following an October meeting between NHDES and PSNH/NU, ENGI, and CVPS, Metcalf & Eddy, Inc. (M&E), in December 2000, submitted a Supplemental Site Investigation Work Plan on behalf of PSNH/NU, ENGI, and CVPS to NHDES.

   - NHDES provided written comments on the Supplemental Site Investigation Work Plan in April, 2001.

   - M&E submitted a letter response to NHDES comments on the Work Plan to NHDES in early June 2001.

   - NHDES approved the Supplemental Site Investigation Work Plan and letter addendum in late June 2001.

- PSNH/NU, in conjunction with CVPS and ENGI, submitted the M&E Supplemental Site Investigation Report to the DES on August 9, 2002.

- Since 2002, PSNH has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Supplemental Site Investigation completed. Please contact PSNH or NHDES for current status.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Dover MGP, which began operation in 1850, was included in that transaction. GSI operated the Dover MGP until 1956, when it was sold to Allied New Hampshire Gas Company (Allied). Approximately 10 months after that sale, the MGP was shut down when natural gas arrived in Dover. Allied merged into Northern Utilities in 1969, and Northern Utilities continued to own the property until 1978. At that time, the property was sold to Estelle Maglaras, the current owner. The majority of the property is used by the Maglaras family as a marina and boatyard. Northern Utilities, Inc. maintains a regulator station on a small portion of the former MGP property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Mediation between PSNH, ENGI, CVPS and Northern Utilities for allocation was undertaken in the fall of 2001 but was not successful. Since that time, PSNH reached a confidential settlement and allocation with CVPS, and has taken the lead on site investigation and remediation activities. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments. PSNH and ENGI have attempted to negotiate an allocation but thus far have been unsuccessful.

   Insurance recovery efforts are complete, and resulted in several confidential settlements as well as a judgment in favor of coverage. Trial was conducted in the United States District Court in February, 2005. At the close of the defendant's case, the court directed a verdict in ENGI's favor on the issue of coverage determining that the defendant is liable for environmental costs related to the site. In May, 2005, the court ordered Century Indemnity to reimburse ENGI's attorneys' fees and costs associated with the litigation. In June 2005, the Court issued an Amended Judgment awarding fees to ENGI. Century appealed the Amended Judgment and oral argument was heard in January 2006. Century's appeal was

LINE
NO.

denied by the Court in June 2006, and ENGI was ultimately awarded its attorneys fees associated with that appeal.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
SITE NAME: DOVER - REMEDIATION
KEYSPAN PROJECT DEF059

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1						
2						-
3		**NO ACTIVITY FOR THIS PERIOD**				-
4						
5	**Total Pool Activity**		**-**	**-**	**-**	**-**

00000173

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
DOVER - LITIGATION
KEYSPAN PROJECT DEF060

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Insurance Recovery		-		(89,362.75)	(89,362.75)
2	Insurance Recovery		-		(3,584.00)	(3,584.00)
3			-			-
4			-			-
5	**Total Pool Activity**		**-**	**-**	**(92,946.75)**	**(92,946.75)**

00000174

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

KEENE FORMER MGP

LINE
NO.

1. SITE LOCATION: 207 and 227 Emerald Street, Keene, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: Information on site investigation activities comes from reports prepared by Public Service Company of New Hampshire (PSNH). It is apparent the New Hampshire Department of Environmental Services (NHDES) first investigated Mill Creek adjacent to the former Keene Manufactured Gas Plant (MGP) in 1986. PSNH, a former owner and operator, and its parent company, Northeast Utilities Service Company (NU), conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a Site Investigation in 1996 in response to a notice letter from the NHDES, which designated the site DES # 199412009. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. Although it does not appear to have been actively involved in the site study, Keene Gas Corporation (KGC) received a notice letter from NHDES in January 1999. In response to a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Natural Gas, Inc. (ENGI) in April 2001. ENGI responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI entered into a confidential agreement with PSNH relative to the development and execution of a Remedial Action Plan (RAP) for the aquatic portion of the site in January 2005. Subsequently, in March 2005, ENGI and PSNH/NU submitted a Scope of Work for the ecological evaluation of the Ashuelot River Sediments to NHDES, and met with NHDES on April 25, 2005 to discuss the conceptual RAP (consisting of sediment removal and stream bed restoration) for Mill Creek/Ashuelot River. NHDES approved the scope of the ecological evaluation, and it was conducted in 2005. In February 2006, PSNH submitted a scope of work for a supplemental investigation of the Ashuelot River, which was approved by NHDES in April 2006. This work was completed and in response in February 2007 NHDES requested a Remedial Action Plan (RAP) for Mill Creek and a portion of the Ashuelot River. NHDES files indicate that PSNH submitted the RAP in 2008 and is proceeding with permitting and obtaining access from private property owners for the Mill Creek and Ashuelot River remediation activities.

LINE
NO.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Remediation of the terrestrial portion of the site was completed by PSNH/NU in 2004/2005. An ecological risk assessment in support of a Remedial Action Plan for the Ashuelot River and Mill Creek portions of the site was conducted jointly by ENGI and PSNH/NU in 2005. A supplemental investigation of the Ashuelot River to support the preparation of a Remedial Action Plan (RAP) was completed in 2007 and NHDES has requested PSNH/NU submit the RAP for Mill Creek and portions of the Ashuelot River in 2007. NHDES files indicate that the RAP was submitted by PSNH in 2008 and that NHDES has commented on the RAP. PSNH has taken the lead on investigation at this Site, and so has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: Given its status at the site, ENGI has not yet conducted a thorough evaluation of its history. It is known that the plant became operational in approximately 1860 and operated as a manufactured gas plant until 1952, after which it was converted to butane and later to propane. Gas Service, Inc., a predecessor of ENGI, owned the former MGP between October 1945 and its closure in 1952. Gas Service continued to own the property until it was sold to KGC in 1979. KGC continues to operate a propane-air plant at the site. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on site history, use and ownership.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS:

   Insurance recovery claims are underway, and confidential settlements have been entered into with all but one defendant. The case is currently stayed. Trial had been scheduled for October 2006 against the sole remaining insurance company defendant, Century Indemnity, however that trial was put off while awaiting a ruling on an issue of law in the Manchester MGP litigation by the New Hampshire Supreme Court. The Supreme Court has since ruled on the appropriate method of allocating indemnification obligations among multiple insurers and the applicability of the New Hampshire attorneys fees statute, RSA 491:22-a, which is relevant to the Keene case. In that case, EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007), the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed

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NO.

within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

ENGI intervened in Docket DE 98-123, the proceeding in which the Commission considered the proposed transfer of operating assets from Keene Gas Corporation (KGC) to New Hampshire Gas Corporation (NHGC). ENGI opposed the proposed transfer because it was concerned that the transfer was likely to create a significant, and possibly insurmountable, obstacle to the potential for KGC customers to share in responsibility for any costs associated with environmental liabilities at the Keene MGP site. At the time, ENGI had not been named as a potentially responsible party for the Keene MGP site, nor had it been notified by any PRP of any claimed liability for the site. Nevertheless, ENGI was aware of the possibility that it would receive such a notice at some point in the future. In the KGC/NHGC proceeding, ENGI proposed that the Commission condition any approval of the proposed transfer on NHGC's willingness to assume responsibility for KGC's liability with regard to the site. The Commission ultimately approved the transfer of assets without imposing such a condition, finding among other things that liability for environmental contamination at the Keene MGP site remained speculative at that time and that assignment of any such liability to various parties was not appropriate for determination by the Commission.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - REMEDIATION
KEYSPAN PROJECT DEF055

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Environmental Staff Payroll	Spreadsheet	269.22			269.22
2						
3			-			-
4			-			-
5	**Total Pool Activity**		**269.22**	**-**	**-**	**269.22**

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ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - LITIGATION
KEYSPAN PROJECT DEF071

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	McLane		-	115.50		115.50
2			-			-
3						
4						-
5	**Total Pool Activity**		**-**	**115.50**	**-**	**115.50**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
KEYSPAN PROJECT DEF064

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	Curry Printing	161212	77.07			77.07
2	Curry Printing	161210	120.31			120.31
3	Curry Printing	161211	143.06			143.06
4	Curry Printing	161430	24.59			24.59
5	Environmental Staff Payroll	Spreadsheet	1,061.47			1,061.47
6	Ikon Office Solutions	BOS08080417	1,738.46			1,738.46
7	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(2,207.00)			(2,207.00)
8	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(3,091.00)			(3,091.00)
9	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(1,416.00)			(1,416.00)
10	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(1,216.00)			(1,216.00)
11	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(2,407.00)			(2,407.00)
12	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(4,173.00)			(4,173.00)
13	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(4,208.00)			(4,208.00)
14	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(3,831.00)			(3,831.00)
15	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(4,061.00)			(4,061.00)
16	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(2,048.00)			(2,048.00)
17	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(2,236.00)			(2,236.00)
18	Interest Expense Passback on Overcollection	Spreadsheet Calculation	(1,874.00)			(1,874.00)
19	LECG, LLC	97496	-	707.51		707.51
20	LECG, LLC	95614	-	865.27		865.27
21	LECG, LLC	97481	-	1,175.56		1,175.56
22	LECG, LLC	96419	-	3,055.92		3,055.92
23	LECG, LLC	100009	-	137.37		137.37
24	LECG, LLC	98859	-	258.57		258.57
25	LECG, LLC	100994	-	247.88		247.88
26	McLane	2008080249	1,424.35			1,424.35
27	McLane	2008071224	-	272.00		272.00
28	McLane	2008080250	-	1,122.00		1,122.00
29	Dickstein Shapiro	2230220	-	3,279.89		3,279.89
30	McLane	2009010164	-	170.00		170.00
31	McLane	2008100113	-	733.30		733.30
32	McLane	2008100111	-	3,484.00		3,484.00
33	McLane	2008090238	-	5,134.00		5,134.00
34	McLane	2008110419	-	2,994.70		2,994.70
35	New Hampshire Department of Environmental Services	7580243	600.00			600.00
36	New Hampshire Department of Environmental Services	7579500	200.00			200.00
37	New Hampshire Department of Environmental Services	7580332	495.00			495.00
38	Steven Pantnaude Transcripts	2008094	-	314.60		314.60
39			-			-
40	**Total Pool Activity**		**(26,883.69)**	**23,952.57**	**-**	**(2,931.12)**

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ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.12 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	$16.43 MMBTU of Peak MDQ.

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH

Calculation of Supplier Balancing Charge

Rate: **$0.12 /MMBtu**

	Rate	Volume	Total	
Injection Cost	$0.0102	**642,312**	$6,552	
Withdrawal Cost	$0.0102	**352,087**	$3,591	
Delivery Rate	$0.0378	352,087	$13,312	
FTA Demand Charge	$0.1936	352,087	$68,180	
FTA Commodity Charge	$0.0834	352,087	$29,364	
		Total Cost	$120,998	
	Absolute Value of the	Sendout Error	**994,399**	MMBtu
		Rate	$ 0.12	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

TGP FSMA Injection Charge	$0.0102	/ MMBtu
TGP FSMA Withdrawal Charge	$0.0102	/ MMBtu
TGP FSMA Deliverability Charge	$1.15	/ MMBtu per month
	$0.0378	/ MMBtu per day
TGP Z4-6 Demand Charge	$5.89	/ MMBtu per month
	$0.1936	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.0834	/ MMBtu

EnergyNorth Natural Gas Inc.
d/b/a National Grid NH

Calculation of Supplier Balancing Charge

Estimated Monthly Imbalances

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov	751	753	-2	1,339,398	1,342,670	-3,272	98,163	47,446	50,718
Dec	1,111	1,082	29	2,051,109	2,006,030	45,079	191,199	118,139	73,060
Jan	1,448	1,391	57	2,673,835	2,582,658	91,177	161,559	126,368	35,191
Feb	1,048	1,019	29	2,039,747	1,994,269	45,478	130,160	87,819	42,341
Mar	922	907	15	1,617,693	1,591,727	25,966	159,487	92,727	66,761
Apr	475	464	11	853,313	837,632	15,681	57,498	36,590	20,908
May	285	245	40	579,395	544,605	34,791	71,321	53,056	18,265
Jun	19	34	-15	320,497	324,546	-4,049	8,907	2,429	6,478
Jul	0	0	0	290,656	290,656	0	0	0	0
Aug	9	12	-3	302,840	302,840	0	0	0	0
Sep	122	113	9	347,441	343,566	3,875	15,070	9,472	5,597
Oct	493	467	26	814,937	779,438	35,499	101,034	68,266	32,768
Total	**6,683**	**6,487**	**196**	**13,230,862**	**12,940,638**	**290,225**	**994,399**	**642,312**	**352,087**

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
May 1, 08	15	16	-1	23,740	24,610	-870	870	0	870
May 2, 08	14	21	-7	22,871	28,959	-6,088	6,088	0	6,088
May 3, 08	18	19	-1	26,350	27,220	-870	870	0	870
May 4, 08	17	18	-1	25,480	26,350	-870	870	0	870
May 5, 08	9	8	1	18,522	17,652	870	870	870	0
May 6, 08	5	3	2	15,043	13,303	1,740	1,740	1,740	0
May 7, 08	6	0	6	15,913	10,694	5,219	5,219	5,219	0
May 8, 08	5	2	3	15,043	12,433	2,609	2,609	2,609	0
May 9, 08	15	14	1	23,740	22,871	870	870	870	0
May 10, 08	15	13	2	23,740	22,001	1,740	1,740	1,740	0
May 11, 08	13	12	1	22,001	21,131	870	870	870	0
May 12, 08	19	13	6	27,220	22,001	5,219	5,219	5,219	0
May 13, 08	10	7	3	19,392	16,782	2,609	2,609	2,609	0
May 14, 08	6	6	0	15,913	15,913	0	0	0	0
May 15, 08	8	8	0	17,652	17,652	0	0	0	0
May 16, 08	11	10	1	20,261	19,392	870	870	870	0
May 17, 08	7	2	5	16,782	12,433	4,349	4,349	4,349	0
May 18, 08	10	10	0	19,392	19,392	0	0	0	0
May 19, 08	11	13	-2	20,261	22,001	-1,740	1,740	0	1,740
May 20, 08	12	7	5	21,131	16,782	4,349	4,349	4,349	0
May 21, 08	12	10	2	21,131	19,392	1,740	1,740	1,740	0
May 22, 08	14	12	2	22,871	21,131	1,740	1,740	1,740	0
May 23, 08	8	6	2	17,652	15,913	1,740	1,740	1,740	0
May 24, 08	7	5	2	16,782	15,043	1,740	1,740	1,740	0
May 25, 08	2	0	2	12,433	10,694	1,740	1,740	1,740	0
May 26, 08	0	0	0	10,694	10,694	0	0	0	0
May 27, 08	1	0	1	11,564	10,694	870	870	870	0
May 28, 08	10	1	9	19,392	11,564	7,828	7,828	7,828	0
May 29, 08	0	9	-9	10,694	18,522	-7,828	7,828	0	7,828
May 30, 08	1	0	1	11,564	10,694	870	870	870	0
May 31, 08	4	0	4	14,173	10,694	3,479	3,479	3,479	0
Jun 1, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 2, 08	2	0	2	11,052	10,512	540	540	540	0
Jun 3, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 4, 08	6	7	-1	12,132	12,402	-270	270	0	270
Jun 5, 08	3	7	-4	11,322	12,402	-1,080	1,080	0	1,080
Jun 6, 08	0	6	-6	10,512	12,132	-1,619	1,619	0	1,619
Jun 7, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 8, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 9, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 10, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 11, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 12, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 13, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 14, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 15, 08	0	6	-6	10,512	12,132	-1,619	1,619	0	1,619
Jun 16, 08	0	3	-3	10,512	11,322	-810	810	0	810
Jun 17, 08	2	0	2	11,052	10,512	540	540	540	0
Jun 18, 08	4	1	3	11,592	10,782	810	810	810	0
Jun 19, 08	2	0	2	11,052	10,512	540	540	540	0
Jun 20, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 21, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 22, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 23, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 24, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 25, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 26, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 27, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 28, 08	0	4	-4	10,512	11,592	-1,080	1,080	0	1,080
Jun 29, 08	0	0	0	10,512	10,512	0	0	0	0
Jun 30, 08	0	0	0	10,512	10,512	0	0	0	0
Jul 1, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 2, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 3, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 4, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 5, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 6, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 7, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 8, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 9, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 10, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 11, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 12, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 13, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 14, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 15, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 16, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 17, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 18, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 19, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 20, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 21, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 22, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 23, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 24, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 25, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 26, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 27, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 28, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 29, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 30, 08	0	0	0	9,376	9,376	0	0	0	0
Jul 31, 08	0	0	0	9,376	9,376	0	0	0	0
Aug 1, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 2, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 3, 08	0	0	0	9,769	9,769	0	0	0	0

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Aug 4, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 5, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 6, 08	2	2	0	9,769	9,769	0	0	0	0
Aug 7, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 8, 08	1	0	1	9,769	9,769	0	0	0	0
Aug 9, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 10, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 11, 08	0	2	-2	9,769	9,769	0	0	0	0
Aug 12, 08	1	0	1	9,769	9,769	0	0	0	0
Aug 13, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 14, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 15, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 16, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 17, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 18, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 19, 08	2	4	-2	9,769	9,769	0	0	0	0
Aug 20, 08	0	2	-2	9,769	9,769	0	0	0	0
Aug 21, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 22, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 23, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 24, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 25, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 26, 08	3	2	1	9,769	9,769	0	0	0	0
Aug 27, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 28, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 29, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 30, 08	0	0	0	9,769	9,769	0	0	0	0
Aug 31, 08	0	0	0	9,769	9,769	0	0	0	0
Sep 1, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 2, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 3, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 4, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 5, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 6, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 7, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 8, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 9, 08	1	2	-1	10,261	10,692	-431	431	0	431
Sep 10, 08	8	8	0	13,275	13,275	0	0	0	0
Sep 11, 08	4	5	-1	11,553	11,983	-431	431	0	431
Sep 12, 08	1	2	-1	10,261	10,692	-431	431	0	431
Sep 13, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 14, 08	0	0	0	9,830	9,830	0	0	0	0
Sep 15, 08	4	0	4	11,553	9,830	1,722	1,722	1,722	0
Sep 16, 08	6	8	-2	12,414	13,275	-861	861	0	861
Sep 17, 08	1	3	-2	10,261	11,122	-861	861	0	861
Sep 18, 08	11	10	1	14,567	14,136	431	431	431	0
Sep 19, 08	13	16	-3	15,428	16,719	-1,292	1,292	0	1,292
Sep 20, 08	7	10	-3	12,844	14,136	-1,292	1,292	0	1,292
Sep 21, 08	6	1	5	12,414	10,261	2,153	2,153	2,153	0
Sep 22, 08	13	12	1	15,428	14,997	431	431	431	0
Sep 23, 08	10	10	0	14,136	14,136	0	0	0	0
Sep 24, 08	8	8	0	13,275	13,275	0	0	0	0
Sep 25, 08	8	8	0	13,275	13,275	0	0	0	0
Sep 26, 08	8	5	3	13,275	11,983	1,292	1,292	1,292	0
Sep 27, 08	2	0	2	10,692	9,830	861	861	861	0
Sep 28, 08	2	0	2	10,692	9,830	861	861	861	0
Sep 29, 08	3	0	3	11,122	9,830	1,292	1,292	1,292	0
Sep 30, 08	6	5	1	12,414	11,983	431	431	431	0
Oct 1, 08	7	6	1	14,132	12,767	1,365	1,365	1,365	0
Oct 2, 08	11	13	-2	19,594	22,324	-2,731	2,731	0	2,731
Oct 3, 08	17	15	2	27,786	25,055	2,731	2,731	2,731	0
Oct 4, 08	15	16	-1	25,055	26,420	-1,365	1,365	0	1,365
Oct 5, 08	16	14	2	26,420	23,690	2,731	2,731	2,731	0
Oct 6, 08	16	18	-2	26,420	29,151	-2,731	2,731	0	2,731
Oct 7, 08	15	13	2	25,055	22,324	2,731	2,731	2,731	0
Oct 8, 08	9	6	3	16,863	12,767	4,096	4,096	4,096	0
Oct 9, 08	7	2	5	14,132	7,306	6,827	6,827	6,827	0
Oct 10, 08	10	9	1	18,228	16,863	1,365	1,365	1,365	0
Oct 11, 08	13	11	2	22,324	19,594	2,731	2,731	2,731	0
Oct 12, 08	10	8	2	18,228	15,498	2,731	2,731	2,731	0
Oct 13, 08	10	9	1	18,228	16,863	1,365	1,365	1,365	0
Oct 14, 08	6	9	-3	12,767	16,863	-4,096	4,096	0	4,096
Oct 15, 08	7	8	-1	14,132	15,498	-1,365	1,365	0	1,365
Oct 16, 08	14	11	3	23,690	19,594	4,096	4,096	4,096	0
Oct 17, 08	20	20	0	31,882	31,882	0	0	0	0
Oct 18, 08	21	23	-2	33,247	35,978	-2,731	2,731	0	2,731
Oct 19, 08	18	26	-8	29,151	40,074	-10,923	10,923	0	10,923
Oct 20, 08	16	18	-2	26,420	29,151	-2,731	2,731	0	2,731
Oct 21, 08	19	16	3	30,516	26,420	4,096	4,096	4,096	0
Oct 22, 08	27	25	2	41,439	38,708	2,731	2,731	2,731	0
Oct 23, 08	27	28	-1	41,439	42,804	-1,365	1,365	0	1,365
Oct 24, 08	20	17	3	31,882	27,786	4,096	4,096	4,096	0
Oct 25, 08	11	7	4	19,594	14,132	5,461	5,461	5,461	0
Oct 26, 08	13	14	-1	22,324	23,690	-1,365	1,365	0	1,365
Oct 27, 08	17	11	6	27,786	19,594	8,192	8,192	8,192	0
Oct 28, 08	24	21	3	37,343	33,247	4,096	4,096	4,096	0
Oct 29, 08	28	28	0	42,804	42,804	0	0	0	0
Oct 30, 08	29	30	-1	44,170	45,535	-1,365	1,365	0	1,365
Oct 31, 08	20	15	5	31,882	25,055	6,827	6,827	6,827	0
Nov 1, 08	28	25	3	49,500	44,592	4,908	4,908	4,908	0
Nov 2, 08	28	31	-3	49,500	54,408	-4,908	4,908	0	4,908
Nov 3, 08	21	22	-1	38,048	39,684	-1,636	1,636	0	1,636
Nov 4, 08	11	11	0	21,687	21,687	0	0	0	0
Nov 5, 08	11	8	3	21,687	16,779	4,908	4,908	4,908	0
Nov 6, 08	10	7	3	20,051	15,143	4,908	4,908	4,908	0
Nov 7, 08	10	7	3	20,051	15,143	4,908	4,908	4,908	0

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov 8, 08	10	8	2	20,051	16,779	3,272	3,272	3,272	0
Nov 9, 08	18	16	2	33,140	29,868	3,272	3,272	3,272	0
Nov 10, 08	24	25	-1	42,956	44,592	-1,636	1,636	0	1,636
Nov 11, 08	27	24	3	47,864	42,956	4,908	4,908	4,908	0
Nov 12, 08	28	29	-1	49,500	51,136	-1,636	1,636	0	1,636
Nov 13, 08	21	22	-1	38,048	39,684	-1,636	1,636	0	1,636
Nov 14, 08	12	13	-1	23,323	24,959	-1,636	1,636	0	1,636
Nov 15, 08	6	3	3	13,507	8,599	4,908	4,908	4,908	0
Nov 16, 08	24	24	0	42,956	42,956	0	0	0	0
Nov 17, 08	30	30	0	52,772	52,772	0	0	0	0
Nov 18, 08	33	37	-4	57,680	64,225	-6,544	6,544	0	6,544
Nov 19, 08	38	41	-3	65,861	70,769	-4,908	4,908	0	4,908
Nov 20, 08	37	39	-2	64,225	67,497	-3,272	3,272	0	3,272
Nov 21, 08	40	41	-1	69,133	70,769	-1,636	1,636	0	1,636
Nov 22, 08	41	44	-3	70,769	75,677	-4,908	4,908	0	4,908
Nov 23, 08	36	40	-4	62,589	69,133	-6,544	6,544	0	6,544
Nov 24, 08	28	25	3	49,500	44,592	4,908	4,908	4,908	0
Nov 25, 08	24	24	0	42,956	42,956	0	0	0	0
Nov 26, 08	30	31	-1	52,772	54,408	-1,636	1,636	0	1,636
Nov 27, 08	31	31	0	54,408	54,408	0	0	0	0
Nov 28, 08	29	30	-1	51,136	52,772	-1,636	1,636	0	1,636
Nov 29, 08	31	35	-4	54,408	60,953	-6,544	6,544	0	6,544
Nov 30, 08	34	30	4	59,317	52,772	6,544	6,544	6,544	0
Dec 1, 08	32	24	8	60,198	47,762	12,436	12,436	12,436	0
Dec 2, 08	31	31	0	58,643	58,643	0	0	0	0
Dec 3, 08	30	28	2	57,089	53,980	3,109	3,109	3,109	0
Dec 4, 08	31	26	5	58,643	50,871	7,772	7,772	7,772	0
Dec 5, 08	37	38	-1	67,970	69,524	-1,554	1,554	0	1,554
Dec 6, 08	35	34	1	64,861	63,307	1,554	1,554	1,554	0
Dec 7, 08	39	43	-4	71,079	77,297	-6,218	6,218	0	6,218
Dec 8, 08	42	50	-8	75,742	88,178	-12,436	12,436	0	12,436
Dec 9, 08	25	19	6	49,316	39,990	9,327	9,327	9,327	0
Dec 10, 08	25	23	2	49,316	46,208	3,109	3,109	3,109	0
Dec 11, 08	33	33	0	61,752	61,752	0	0	0	0
Dec 12, 08	41	35	6	74,188	64,861	9,327	9,327	9,327	0
Dec 13, 08	52	45	7	91,287	80,406	10,881	10,881	10,881	0
Dec 14, 08	32	25	7	60,198	49,316	10,881	10,881	10,881	0
Dec 15, 08	20	14	6	41,544	32,217	9,327	9,327	9,327	0
Dec 16, 08	36	38	-2	66,416	69,524	-3,109	3,109	0	3,109
Dec 17, 08	37	40	-3	67,970	72,633	-4,663	4,663	0	4,663
Dec 18, 08	37	38	-1	67,970	69,524	-1,554	1,554	0	1,554
Dec 19, 08	47	50	-3	83,515	88,178	-4,663	4,663	0	4,663
Dec 20, 08	49	51	-2	86,624	89,732	-3,109	3,109	0	3,109
Dec 21, 08	39	47	-8	71,079	83,515	-12,436	12,436	0	12,436
Dec 22, 08	49	51	-2	86,624	89,732	-3,109	3,109	0	3,109
Dec 23, 08	46	41	5	81,960	74,188	7,772	7,772	7,772	0
Dec 24, 08	27	22	5	52,425	44,653	7,772	7,772	7,772	0
Dec 25, 08	35	35	0	64,861	64,861	0	0	0	0
Dec 26, 08	31	34	-3	58,643	63,307	-4,663	4,663	0	4,663
Dec 27, 08	24	25	-1	47,762	49,316	-1,554	1,554	0	1,554
Dec 28, 08	30	18	12	57,089	38,435	18,654	18,654	18,654	0
Dec 29, 08	33	29	4	61,752	55,534	6,218	6,218	6,218	0
Dec 30, 08	35	39	-4	64,861	71,079	-6,218	6,218	0	6,218
Dec 31, 08	51	56	-5	89,732	97,505	-7,772	7,772	0	7,772
Jan 1, 09	52	54	-2	94,715	97,914	-3,199	3,199	0	3,199
Jan 2, 09	41	44	-3	77,120	81,918	-4,799	4,799	0	4,799
Jan 3, 09	43	42	1	80,319	78,719	1,600	1,600	1,600	0
Jan 4, 09	38	37	1	72,321	70,721	1,600	1,600	1,600	0
Jan 5, 09	37	35	2	70,721	67,522	3,199	3,199	3,199	0
Jan 6, 09	38	36	2	72,321	69,122	3,199	3,199	3,199	0
Jan 7, 09	37	38	-1	70,721	72,321	-1,600	1,600	0	1,600
Jan 8, 09	41	40	1	77,120	75,520	1,600	1,600	1,600	0
Jan 9, 09	50	46	4	91,516	85,118	6,398	6,398	6,398	0
Jan 10, 09	46	45	1	85,118	83,518	1,600	1,600	1,600	0
Jan 11, 09	48	46	2	88,317	85,118	3,199	3,199	3,199	0
Jan 12, 09	44	49	-5	81,918	89,916	-7,998	7,998	0	7,998
Jan 13, 09	38	40	-2	72,321	75,520	-3,199	3,199	0	3,199
Jan 14, 09	56	55	1	101,113	99,514	1,600	1,600	1,600	0
Jan 15, 09	59	63	-4	105,912	112,311	-6,398	6,398	0	6,398
Jan 16, 09	59	59	0	105,912	105,912	0	0	0	0
Jan 17, 09	54	51	3	97,914	93,116	4,799	4,799	4,799	0
Jan 18, 09	43	48	-5	80,319	88,317	-7,998	7,998	0	7,998
Jan 19, 09	48	43	5	88,317	80,319	7,998	7,998	7,998	0
Jan 20, 09	51	46	5	93,116	85,118	7,998	7,998	7,998	0
Jan 21, 09	50	44	6	91,516	81,918	9,598	9,598	9,598	0
Jan 22, 09	45	35	10	83,518	67,522	15,996	15,996	15,996	0
Jan 23, 09	35	30	5	67,522	59,524	7,998	7,998	7,998	0
Jan 24, 09	56	51	5	101,113	93,116	7,998	7,998	7,998	0
Jan 25, 09	57	52	5	102,713	94,715	7,998	7,998	7,998	0
Jan 26, 09	56	50	6	101,113	91,516	9,598	9,598	9,598	0
Jan 27, 09	50	45	5	91,516	83,518	7,998	7,998	7,998	0
Jan 28, 09	41	38	3	77,120	72,321	4,799	4,799	4,799	0
Jan 29, 09	45	43	2	83,518	80,319	3,199	3,199	3,199	0
Jan 30, 09	43	40	3	80,319	75,520	4,799	4,799	4,799	0
Jan 31, 09	47	46	1	86,717	85,118	1,600	1,600	1,600	0
Feb 1, 09	38	43	-5	71,042	78,883	-7,841	7,841	0	7,841
Feb 2, 09	33	31	2	63,201	60,065	3,136	3,136	3,136	0
Feb 3, 09	41	43	-2	75,747	78,883	-3,136	3,136	0	3,136
Feb 4, 09	48	52	-4	86,724	92,997	-6,273	6,273	0	6,273
Feb 5, 09	55	54	1	97,701	96,133	1,568	1,568	1,568	0
Feb 6, 09	41	50	-9	75,747	89,860	-14,114	14,114	0	14,114
Feb 7, 09	29	24	5	56,928	49,087	7,841	7,841	7,841	0
Feb 8, 09	39	32	7	72,610	61,633	10,977	10,977	10,977	0
Feb 9, 09	46	39	7	83,588	72,610	10,977	10,977	10,977	0
Feb 10, 09	33	34	-1	63,201	64,769	-1,568	1,568	0	1,568
Feb 11, 09	24	23	1	49,087	47,519	1,568	1,568	1,568	0

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Feb 12, 09	29	27	2	56,928	53,792	3,136	3,136	3,136	0
Feb 13, 09	43	39	4	78,883	72,610	6,273	6,273	6,273	0
Feb 14, 09	40	35	5	74,178	66,337	7,841	7,841	7,841	0
Feb 15, 09	39	36	3	72,610	67,906	4,705	4,705	4,705	0
Feb 16, 09	41	37	4	75,747	69,474	6,273	6,273	6,273	0
Feb 17, 09	39	40	-1	72,610	74,178	-1,568	1,568	0	1,568
Feb 18, 09	32	31	1	61,633	60,065	1,568	1,568	1,568	0
Feb 19, 09	34	35	-1	64,769	66,337	-1,568	1,568	0	1,568
Feb 20, 09	40	40	0	74,178	74,178	0	0	0	0
Feb 21, 09	36	36	0	67,906	67,906	0	0	0	0
Feb 22, 09	36	33	3	67,906	63,201	4,705	4,705	4,705	0
Feb 23, 09	43	42	1	78,883	77,315	1,568	1,568	1,568	0
Feb 24, 09	44	41	3	80,451	75,747	4,705	4,705	4,705	0
Feb 25, 09	37	36	1	69,474	67,906	1,568	1,568	1,568	0
Feb 26, 09	29	29	0	56,928	56,928	0	0	0	0
Feb 27, 09	24	18	6	49,087	39,678	9,409	9,409	9,409	0
Feb 28, 09	35	39	-4	66,337	72,610	-6,273	6,273	0	6,273
Mar 1, 09	42	42	0	75,662	75,662	0	0	0	0
Mar 2, 09	42	47	-5	75,662	84,753	-9,091	9,091	0	9,091
Mar 3, 09	52	48	4	93,843	86,571	7,273	7,273	7,273	0
Mar 4, 09	49	46	3	88,389	82,934	5,455	5,455	5,455	0
Mar 5, 09	37	30	7	66,571	53,844	12,727	12,727	12,727	0
Mar 6, 09	27	21	6	48,389	37,480	10,909	10,909	10,909	0
Mar 7, 09	21	19	2	37,480	33,844	3,636	3,636	3,636	0
Mar 8, 09	26	22	4	46,571	39,298	7,273	7,273	7,273	0
Mar 9, 09	29	36	-7	52,026	64,753	-12,727	12,727	0	12,727
Mar 10, 09	29	28	1	52,026	50,207	1,818	1,818	1,818	0
Mar 11, 09	28	25	3	50,207	44,753	5,455	5,455	5,455	0
Mar 12, 09	40	39	1	72,025	70,207	1,818	1,818	1,818	0
Mar 13, 09	38	37	1	68,389	66,571	1,818	1,818	1,818	0
Mar 14, 09	26	27	-1	46,571	48,389	-1,818	1,818	0	1,818
Mar 15, 09	26	23	3	46,571	41,117	5,455	5,455	5,455	0
Mar 16, 09	29	32	-3	52,026	57,480	-5,455	5,455	0	5,455
Mar 17, 09	28	26	2	50,207	46,571	3,636	3,636	3,636	0
Mar 18, 09	17	13	4	30,208	22,935	7,273	7,273	7,273	0
Mar 19, 09	25	26	-1	44,753	46,571	-1,818	1,818	0	1,818
Mar 20, 09	32	33	-1	57,480	59,298	-1,818	1,818	0	1,818
Mar 21, 09	27	29	-2	48,389	52,026	-3,636	3,636	0	3,636
Mar 22, 09	27	32	-5	48,389	57,480	-9,091	9,091	0	9,091
Mar 23, 09	36	40	-4	64,753	72,025	-7,273	7,273	0	7,273
Mar 24, 09	32	29	3	57,480	52,026	5,455	5,455	5,455	0
Mar 25, 09	29	25	4	52,026	44,753	7,273	7,273	7,273	0
Mar 26, 09	23	21	2	41,117	37,480	3,636	3,636	3,636	0
Mar 27, 09	20	19	1	35,662	33,844	1,818	1,818	1,818	0
Mar 28, 09	19	22	-3	33,844	39,298	-5,455	5,455	0	5,455
Mar 29, 09	22	25	-3	39,298	44,753	-5,455	5,455	0	5,455
Mar 30, 09	23	23	0	41,117	41,117	0	0	0	0
Mar 31, 09	21	22	-1	37,480	39,298	-1,818	1,818	0	1,818
Apr 1, 09	23	24	-1	38,744	40,051	-1,307	1,307	0	1,307
Apr 2, 09	17	13	4	30,903	25,676	5,227	5,227	5,227	0
Apr 3, 09	18	16	2	32,210	29,597	2,614	2,614	2,614	0
Apr 4, 09	22	23	-1	37,437	38,744	-1,307	1,307	0	1,307
Apr 5, 09	20	20	0	34,824	34,824	0	0	0	0
Apr 6, 09	20	23	-3	34,824	38,744	-3,920	3,920	0	3,920
Apr 7, 09	24	26	-2	40,051	42,664	-2,614	2,614	0	2,614
Apr 8, 09	25	26	-1	41,358	42,664	-1,307	1,307	0	1,307
Apr 9, 09	19	18	1	33,517	32,210	1,307	1,307	1,307	0
Apr 10, 09	18	14	4	32,210	26,983	5,227	5,227	5,227	0
Apr 11, 09	26	26	0	42,664	42,664	0	0	0	0
Apr 12, 09	28	30	-2	45,278	47,891	-2,614	2,614	0	2,614
Apr 13, 09	24	21	3	40,051	36,130	3,920	3,920	3,920	0
Apr 14, 09	20	19	1	34,824	33,517	1,307	1,307	1,307	0
Apr 15, 09	20	20	0	34,824	34,824	0	0	0	0
Apr 16, 09	19	19	0	33,517	33,517	0	0	0	0
Apr 17, 09	9	7	2	20,449	17,836	2,614	2,614	2,614	0
Apr 18, 09	15	14	1	28,290	26,983	1,307	1,307	1,307	0
Apr 19, 09	23	20	3	38,744	34,824	3,920	3,920	3,920	0
Apr 20, 09	21	19	2	36,130	33,517	2,614	2,614	2,614	0
Apr 21, 09	14	15	-1	26,983	28,290	-1,307	1,307	0	1,307
Apr 22, 09	10	15	-5	21,756	28,290	-6,534	6,534	0	6,534
Apr 23, 09	15	16	-1	28,290	29,597	-1,307	1,307	0	1,307
Apr 24, 09	5	4	1	15,222	13,915	1,307	1,307	1,307	0
Apr 25, 09	0	0	0	8,688	8,688	0	0	0	0
Apr 26, 09	0	0	0	8,688	8,688	0	0	0	0
Apr 27, 09	0	0	0	8,688	8,688	0	0	0	0
Apr 28, 09	0	0	0	8,688	8,688	0	0	0	0
Apr 29, 09	13	12	1	25,676	24,369	1,307	1,307	1,307	0
Apr 30, 09	7	4	3	17,836	13,915	3,920	3,920	3,920	0
May 1, 09	0	0	0	10,694	10,694	0	0	0	0
May	285	245	40	579,395	544,605	34,791	71,321	53,056	18,265
Jun	19	34	-15	320,497	324,546	-4,049	8,907	2,429	6,478
Jul	0	0	0	290,656	290,656	0	0	0	0
Aug	9	12	-3	302,840	302,840	0	0	0	0
Sep	122	113	9	347,441	343,566	3,875	15,070	9,472	5,597
Oct	493	467	26	814,937	779,438	35,499	101,034	68,266	32,768
Nov	751	753	-2	1,339,398	1,342,670	-3,272	98,163	47,446	50,718
Dec	1,111	1,082	29	2,051,109	2,006,030	45,079	191,199	118,139	73,060
Jan	1,448	1,391	57	2,673,835	2,582,658	91,177	161,559	126,368	35,191
Feb	1,090	1,061	29	2,039,747	1,994,269	45,478	130,160	87,819	42,341
Mar	903	889	14	1,617,693	1,591,727	25,966	159,487	92,727	66,761
Apr	452	440	12	853,313	837,632	15,681	57,498	36,590	20,908
Total	6,683	6,487	196	13,230,862	12,940,638	290,225	994,399	642,312	352,087
Datacheck	0	0	0	0	0	0	0	0	0

ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

Line	Description	Item	Amount	Unit	Source:
1	Peak Day		143,800	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 33371	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6)	5,000		
10			54,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		60,967	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,019,069		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,749,387		Attachment B: Order No. 23,675 (page 15), Docket DG 00-063,
26	Granite Ridge		$240,000		Attachment B Page 3 Line 1
27	Total		$6,008,456		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$98.55		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$16.43**	**/Dekatherm**	Line 29 divided by 6 month

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ENERGY NORTH NATURAL GAS

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	50.00%	37.00%
Storage	16.00%	20.00%
Peaking	34.00%	43.00%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2009:

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE II*	Supply at Waddington		4,000		$8.0728		10/31/2016	X
	Iroquois	RTS to Wright	470-01	4,047		$6.5971		10/31/2011	
	TGP	NET-NE	33371	4,000		$10.6100		10/31/2011	
	BP Canada Energy Co.**	Supply at Niagara		3,199		$0.0000		03/31/2012	X
	TGP	FT-A (Z5-Z6)	2302	3,122		$4.9300		10/31/2010	
	TGP	FT-A (Z0-Z6)	8587	7,035		$16.5900		10/31/2010	
	TGP	FT-A (Z1-Z6)	8587	14,561		$15.1500		10/31/2010	
	TGP	FT-A (Z6-Z6)	42076	20,000		$3.1600		10/31/2010	
	TGP	FT-A (Z6-Z6)		5,000		$12.1700			
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	$1.1500	$0.0185	10/31/2010	
	TGP	FT-A (Z4-Z6)	632	15,265		$5.8900		10/31/2010	
	TGP	FT-A (Z4-Z6)	8587	3,811		$5.8900		10/31/2010	
	National Fuel	FSS-1 (Storage)	O02357***	6,098	670,800	$2.1556	$0.0432	03/31/2008	
	National Fuel	FST (Transport)	N02358	6,098		$3.3612		03/31/2008	
	TGP	FT-A (Z4-Z6)	11234	6,150		$5.8900		10/31/2010	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	$4.4683	$0.0000	04/01/2008	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$4.9300		10/31/2010	
	Dominion	GSS (Storage)	300076***	934	102,700	$1.8815	$0.0145	03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	932		$5.8900		10/31/2010	
Peaking									
	Energy North	LNG/Propane****		60,967	-	$16.4300	$0.0000		X
	TGP	FT-A (Z6-Z6)		25,000	-	$12.1700	$0.0000		X

* Volumes and Demand Charges are based on MMBtu at the border.
**BP commodity price is based on Inside FERC at Niagara plus $.01 per Dth.
***All gas transferred for storage contracts will be based on LDC's monthly WACOG.
****All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months.

Note: **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/08. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the Energy North Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $27.4017/dth.

ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

			Volume	Rate	Monthly Cost	Months/Year	Annual Cost
1	Granite Ridge - 30 days @ 15,000/dt						
2							
3							
4	Concord Lateral						
5	DOMAC *	FLS 160					
6							
7	Subtotal						**$4,019,068.75 ***
8							
9	**Total**						**$4,259,068.75**
10							

* Contract currently being negotiated for an effective date of November 1, 2009.

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ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	37.0%	20.0%	43.0%	100.0%
G-51	Low Annual /Low Winter Use	50.0%	16.0%	34.0%	100.0%
G-42	Medium Annual / High Winter	37.0%	20.0%	43.0%	100.0%
G-52	High Annual / Low Winter Use	50.0%	16.0%	34.0%	100.0%
G-43	High Annual / High Winter	37.0%	20.0%	43.0%	100.0%
G-53	High Annual / Load Factor < 90%	50.0%	16.0%	34.0%	100.0%
G-54	High Annual / Load Factor < 90%	50.0%	16.0%	34.0%	100.0%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	**Storage**	**Peaking**	**Total**
G-41	**LAHW**	Low Annual C&I - High Winter Use	37.0%	20.0%	43.0%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	50.0%	16.0%	34.0%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	37.0%	20.0%	43.0%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	50.0%	16.0%	34.0%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	37.0%	20.0%	43.0%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	50.0%	16.0%	34.0%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	50.0%	16.0%	34.0%	100.0%

HLF	High Load Factor	50%	16%	34%	100%
LLF	Low Load Factor	37%	20%	43%	100%
	Total	39%	20%	42%	101%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD			80	
		Base load	Heat load	Total
HLF	R-1 RNSH	182	513	695
LLF	R-3 RSH	4,216	63,096	67,313
LLF	G-41 SL	890	24,500	25,390
HLF	G-51 SH	658	2,194	2,852
LLF	G-42 ML	1,899	33,654	35,553
HLF	G-52 MH	1,293	3,067	4,361
LLF	G-43 LL	391	4,515	4,905
HLF	G-53 LLL90	258	1,643	1,901
HLF	G-54 LLG90	260	571	830
	TOTAL	10,046	133,754	143,800

	Base load	Heat load	Total
HLF	2,650	7,989	10,640
LLF	7,396	125,765	133,160
Total	10,046	133,754	143,800

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	182	171	353	108	234	695
R-3 RSH	4,216	21,073	25,290	13,263	28,760	67,313
G-41 SL	890	8,183	9,072	5,150	11,167	25,390
G-51 SH	658	733	1,391	461	1,000	2,852
G-42 ML	1,899	11,240	13,139	7,074	15,340	35,553
G-52 MH	1,293	1,024	2,318	645	1,398	4,361
G-43 LL	391	1,508	1,898	949	2,058	4,905
G-53 LLL90	258	549	807	345	749	1,901
G-54 LLG90	260	191	450	120	260	830
TOTAL	10,046	44,672	54,718	28,115	60,967	143,800

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
HLF	2,650	2,668	5,319	1,679	3,642	10,640
LLF	7,396	42,004	49,399	26,436	57,325	133,160
Total	10,046	44,672	54,718	28,115	60,967	143,800

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	50.8%	15.5%	33.6%	100.0%
R-3 RSH	37.6%	19.7%	42.7%	100.0%
G-41 SL	35.7%	20.3%	44.0%	100.0%
G-51 SH	48.8%	16.2%	35.1%	100.0%
G-42 ML	37.0%	19.9%	43.1%	100.0%
G-52 MH	53.2%	14.8%	32.1%	100.0%
G-43 LL	38.7%	19.3%	42.0%	100.0%
G-53 LLL90	42.4%	18.2%	39.4%	100.0%
G-54 LLG90	54.2%	14.4%	31.3%	100.0%
TOTAL	38.1%	19.6%	42.4%	100.0%

	Pipeline	Storage	Peaking	Total
High Load Factor	50%	16%	34%	100%
Low Load Factor	37%	20%	43%	100%
Total	39%	20%	42%	100%

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Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Allocate Design Day Sendout to Rate Classes

Design DD **80**

	Daily Baseload * 1000	February Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	182	6.039	483	665	27%	0.384%	182	513	695
R-3 RSH	4,216	742.538	59,403	63,619	7%	47.174%	4,216	63,096	67,313
G-41 SL	890	288.322	23,066	23,956	4%	18.317%	890	24,500	25,390
G-51 SH	658	25.825	2,066	2,724	24%	1.641%	658	2,194	2,852
G-42 ML	1,899	396.047	31,684	33,583	6%	25.161%	1,899	33,654	35,553
G-52 MH	1,293	36.099	2,888	4,181	31%	2.293%	1,293	3,067	4,361
G-43 LL	391	53.131	4,250	4,641	8%	3.375%	391	4,515	4,905
G-53 LLL90	258	19.338	1,547	1,805	14%	1.229%	258	1,643	1,901
G-54 LLG90	260	6.718	537	797	33%	0.427%	260	571	830
TOTAL	10,046	1,574.058	125,925	135,971		100.000%	10,046	133,754	143,800

HLF	2,650	94	7,522	10,172
LLF	7,396	1,480	118,403	125,799
Total	10,046	1,574	125,925	135,971

Design Day from 2009-2010 Resource Plan		**143,800**
Design Day from Billing Calculation		135,971
Variance		7,829

7.275	6.534	0.74
789.745	717.273	72.47
292.165	266.783	25.38
29.339	25.026	4.31
385.503	380.322	5.18
36.876	36.107	0.77
41.787	35.702	6.08
8.367	15.098	(6.73)
0.928	0.752	0.18
-	11.884	(11.88)
1,591.984	1,495.481	

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	8	12	15	13	12	10	8	6	6	5	4	6	105	5.642	0.182
LLF	R-3 RSH	405	749	1,087	1,072	847	586	292	187	148	114	127	188	5,802	130.705	4.216
LLF	G-41 SL	113	253	384	395	303	177	85	43	31	24	26	43	1,879	27.584	0.890
HLF	G-51 SH	28	41	50	52	43	32	27	23	22	19	21	23	381	20.387	0.658
LLF	G-42 ML	210	391	545	562	451	300	168	86	61	56	66	96	2,993	58.870	1.899
HLF	G-52 MH	48	64	81	83	72	57	48	44	42	38	39	42	658	40.095	1.293
LLF	G-43 LL	30	53	63	79	78	69	40	25	11	13	15	13	489	12.106	0.391
HLF	G-53 LLL90	5	7	1	32	12	31	20	16	11	5	5	(3)	143	7.994	0.258
HLF	G-54 LLL110	(5)	(5)	39	(7)	10	16	(19)	(4)	5	3	3	3	39	4.793	0.155
HLF	G-63 LLG110	13	20	45	12	(59)	9	16	3	8	(13)	9	(16)	47	3.254	0.105
	TOTAL	855	1,586	2,310	2,292	1,769	1,288	683	431	345	264	315	395	12,535	304.966	9.838
	HLF	97	139	232	183	90	156	99	90	94	57	81	55	1,372	82.165	2.442
	LLF	758	1,447	2,079	2,109	1,679	1,132	585	341	251	208	234	341	11,163	229.264	7.396

Baseload (= the lesser of actual volumes or the average of July and August volumes)

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	5	6	6	5	6	5	6	5	6	5	4	6	66
LLF	R-3 RSH	126	131	131	118	131	126	131	126	148	114	126	131	1,539
LLF	G-41 SL	27	28	28	25	28	27	28	27	31	24	26	28	325
HLF	G-51 SH	20	20	20	18	20	20	20	20	22	19	20	20	240
LLF	G-42 ML	57	59	59	53	59	57	59	57	61	56	57	59	693
HLF	G-52 MH	39	40	40	36	40	39	40	39	42	38	39	40	472
LLF	G-43 LL	12	12	12	11	12	12	12	12	11	13	12	12	143
HLF	G-53 LLL90	5	7	1	7	8	8	8	8	11	5	5	(3)	94
HLF	G-54 LLL110	(5)	(5)	5	(7)	5	5	(19)	(4)	5	3	3	3	39
HLF	G-63 LLG110	3	3	3	3	(59)	3	3	3	8	(13)	3	(16)	38
	TOTAL	289	301	305	270	249	301	287	293	345	264	296	279	3,591
	HLF	67	72	76	63	20	80	58	71	94	57	74	50	950
	LLF	222	229	229	207	229	222	229	222	251	208	222	229	2,699

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
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Heating Volumes (= Actual Volumes - Baseload)

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
HLF	R-1 RNSH	3	6	9	8	6	4	2	1	0	0	0	1	38
LLF	R-3 RSH	278	619	957	954	716	459	161	60	0	0	0	58	4,263
LLF	G-41 SL	86	226	356	370	276	150	57	16	0	0	0	16	1,554
HLF	G-51 SH	8	21	30	33	23	12	6	4	0	0	1	3	141
LLF	G-42 ML	154	332	486	509	392	243	109	29	0	0	9	37	2,300
HLF	G-52 MH	10	24	41	46	31	19	8	6	0	0	0	2	186
LLF	G-43 LL	18	41	50	68	66	58	28	13	0	0	3	1	346
HLF	G-53 LLL90	0	0	0	25	4	23	12	9	0	0	0	0	48
HLF	G-54 LLL110	0	0	34	0	5	11	0	0	0	0	0	0	0
HLF	G-63 LLG110	9	17	42	9	0	6	12	0	0	0	6	0	9
	TOTAL	566	1,285	2,006	2,023	1,520	986	396	138	0	0	19	116	8,945

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
HLF	30	67	156	121	70	76	41	19	0	0	7	5	422
LLF	536	1,217	1,850	1,902	1,450	910	355	119	0	0	12	111	8,464
Actual BDD	649.5	988.0	1321.5	1285.0	1036.5	745.5	375.5	155.5	53.0	10.0	71.5	309.0	7000.5

Heat Factors

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
HLF	R-1 RNSH	0.0044	0.0062	0.0067	0.0060	0.0057	0.0060	0.0054	0.0060	0.0000	0.0000	0.0000	0.0017	
LLF	R-3 RSH	0.4287	0.6262	0.7239	0.7425	0.6910	0.6163	0.4294	0.3887	0.0000	0.0000	0.0040	0.1863	
LLF	G-41 SL	0.1327	0.2285	0.2696	0.2883	0.2661	0.2014	0.1530	0.1054	0.0000	0.0000	0.0000	0.0511	
HLF	G-51 SH	0.0127	0.0211	0.0226	0.0258	0.0221	0.0167	0.0171	0.0226	0.0000	0.0000	0.0112	0.0082	
LLF	G-42 ML	0.2364	0.3357	0.3679	0.3960	0.3780	0.3255	0.2907	0.1885	0.0000	0.0000	0.1268	0.1213	
HLF	G-52 MH	0.0147	0.0238	0.0311	0.0361	0.0304	0.0248	0.0221	0.0361	0.0000	0.0000	0.0000	0.0061	
LLF	G-43 LL	0.0280	0.0415	0.0382	0.0531	0.0638	0.0775	0.0735	0.0851	0.0000	0.0000	0.0439	0.0022	
HLF	G-53 LLL90	0.0000	0.0000	0.0000	0.0193	0.0038	0.0313	0.0308	0.0551	0.0000	0.0000	0.0000	0.0000	
HLF	G-54 LLL110	0.0000	0.0000	0.0261	0.0000	0.0052	0.0152	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
HLF	G-63 LLG110	0.0146	0.0172	0.0317	0.0067	0.0000	0.0083	0.0329	0.0007	0.0000	0.0000	0.0865	0.0000	
	TOTAL	0.8720	1.3003	1.5177	1.5741	1.4661	1.3230	1.0548	0.8882	0.0000	0.0000	0.2724	0.3768	

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	649.5	988.0	1321.5	1285.0	1036.5	745.5	375.5	155.5	53.0	10.0	71.5	309.0	7000.5
Norm Billing DD	639.5	979.1	1240.9	1229.0	1066.6	789.6	445.0	183.1	41.4	18.7	93.1	327.5	7053.2

Normal Volumes (= Heating Volumes * Normal EDD/Actual EDD + Baseload)

		Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
HLF	R-1 RNSH	8	12	14	13	12	10	8	7	6	5	4	6	105
LLF	R-3 RSH	401	744	1,029	1,031	868	613	322	198	148	114	127	192	5,784
LLF	G-41 SL	112	251	362	379	311	186	96	46	31	24	26	44	1,869
HLF	G-51 SH	28	41	48	50	44	33	28	24	22	19	21	23	381
LLF	G-42 ML	208	388	515	540	462	314	188	91	61	56	69	99	2,992
HLF	G-52 MH	48	63	79	81	73	58	50	45	42	38	39	42	658
LLF	G-43 LL	30	53	59	76	80	73	45	27	11	13	16	13	496
HLF	G-53 LLL90	5	7	1	31	12	32	22	18	11	5	5	(3)	147
HLF	G-54 LLL110	(5)	(5)	37	(7)	10	17	(19)	(4)	5	3	3	3	38
HLF	G-63 LLG110	12	20	43	11	(59)	10	18	3	8	(13)	11	(16)	49
	TOTAL	846	1,574	2,188	2,204	1,813	1,346	757	456	345	264	321	402	12,518

HLF	96	138	222	178	92	160	106	93	94	57	83	55	1,376
LLF	750	1,436	1,966	2,026	1,721	1,186	651	362	251	208	238	347	11,141

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6%				$0.3927	$0.3722	$ 943.37	$ 926.93	$ 16.44	1.77%	$0.3927	$0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9%				$0.4724	$0.4628	$ 679.85	$ 672.22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10.90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10.22%
4	Nov 01 - Apr 02	24%				$0.5141	$0.4818	$ 790.65	$ 760.55	$ 30.10	3.96%	$0.5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3.52%
5	Nov 02 - Apr 03	24%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2.27%	$0.5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3.25%	$0.8759	$0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3.34%
7	Nov 04 - Apr 05	30%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189.55	$ (46.60)	-3.92%	$0.9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3.51%
8	Nov 05 - Apr 06	30%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10.90%	$1.3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	15%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415.80	$ 93.99	6.64%	$1.2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	16%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 27.69	1.97%	$1.2044	$1.1725	$ 2,232.39	$2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$1,555.31	$1,373.85	$ 181.46	13.21%	$1.2836	$1.0958	$2,467.49	$2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10 1/					$0.9863	$0.9663	$1,250.80	$1,232.16	$ 18.64	1.51%	$0.9864	$0.9665	$1,984.14	$1,955.74	$ 28.40	1.45%
13																	
14	Total									$ 395.48						$ 589.15	

1/ The total bill calculation reflects the increase in base distribution rates as approved in Order 24,888 in DG 08-009 (Temporary Rates)

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Short Term Debt Limitations

	For Purposes of Fuel Financing
Total Direct Gas Costs	$ 77,870,546
Total Indirect Gas Costs	3,573,460
Total Gas Costs	$ 81,444,006
% of Debt to Total Gas Costs	30%
Short Term Debt	$ 24,433,202

	For Purposes Other Than Fuel Financing
12/1/09 Projected Net Plant	$ 258,105,000
% of Debt to Net Plant	20%
Short Term Debt	$ 51,621,000