STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

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

Summer 2010 Cost of Gas
DG 10-______

Prefiled Testimony of Ann E. Leary

March 15, 2010

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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 NH ("National Grid" or the "Company").

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 County Gas Company by Eastern Enterprises in 1998, I became Manager of Rates for Boston Gas Company and then subsequently for KeySpan Energy Delivery New England after Eastern was acquired by KeySpan Corporation. Since the acquisition of EnergyNorth Natural Gas, Inc. by KeySpan Corporation, I have been responsible for rates related matters for National Grid NH as well. My responsibilities remained the same following the acquisition of KeySpan by National Grid.

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

A. As the Manager of Pricing-New England, I am responsible for preparing and submitting various regulatory filings with both the New Hampshire Public Utilities Commission and the Massachusetts Department of Public Utilities on behalf of the Company's New England local distribution companies, including Boston Gas Company, Essex Gas Company, Colonial Gas Company, and National Grid NH. 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 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 2010 Summer (Off Peak) Period to be effective beginning May 1, 2010.

COST OF GAS FACTOR

Q. What are the proposed 2010 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.7784 per therm for residential customers, $0.7778 per therm for commercial/industrial low winter use customers and $0.7788 per therm for commercial/industrial high winter use customers as shown on Proposed Tenth Revised Page 87.

Q. Would you please explain tariff page Proposed Second Revised Page 86 and Proposed Tenth Revised Page 87?

A. Proposed Second Revised Page 86 and Proposed Tenth Revised Page 87 contain the calculation of the 2010 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout and gas costs. For example, Proposed Tenth Revised Page 87 shows that the 2010 Average Cost of Gas of $0.7784 per therm is derived by adding the Direct Cost of Gas Rate of $0.7612 per therm to the Indirect Cost of Gas Rate of $0.0172 per therm. The estimated total Anticipated Direct Cost of gas is $16,311,546 and the estimated Indirect Cost of Gas is $367,707. The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected firm sales volumes of 21,428,146 therms. Proposed Tenth Revised Page 87 further shows that the Residential Cost of Gas Rate, $0.7784 per therm, is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial Low Winter Use Cost of Gas Rate, $0.7778 per therm, and the Commercial/Industrial High Winter Use Cost of Gas Rate, $0.7788 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed Second Revised Page 86. To derive the total Anticipated Direct Cost of Gas of $16,311,546 the Company starts with the Unadjusted Anticipated Cost of Gas of $16,262,993 and adds the Net Adjustment totaling $48,553.

$16,262,993 + $48,553 = $16,311,546.

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

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1.	Purchased Gas Demand Costs	$3,253,976
2.	Purchased Gas Supply Costs	12,301,578
3.	Produced Gas Cost	77,045
4.	Hedged Contract Costs	630,394
	Total Unadjusted Anticipated Cost of Gas	**$16,262,993**

Q. What are the components of the allowable adjustments to the cost of gas?

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

1.	Prior Period (Over)/Under Collection	$38,753
2.	Interest	9,800
3.	Prior Period Adjustment	0
	Total Adjustments	**$48,553**

Q. **Please briefly discuss the status of prices in the gas commodity market that provides the basis for your initial cost of gas rate for the Summer Period.**

A. As of March 11 2010, the six-month NYMEX futures price strip for the 2010 summer is $0.4994 per therm. The NYMEX strip for this summer reflects current and projected market conditions in the gas industry nationally. The current COG reflects an increase from 2009 primarily resulting from the increase in NYMEX pricing.

Q. How does the proposed average cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2009 Summer Period?

A. The cost of gas rate proposed in this filing is $0.1062 per therm higher than the initial rate approved by the Commission for the 2009 Summer Period ($0.7784 vs. $0.6722). This $0.1062 per therm increase is the result of a $0.0824 per therm increase in prior period reconciliation adjustments and associated interest, a $0.0157 per therm increase in gas costs, and a $.0.0081 per therm increase in indirect gas costs. The 2010 Off Peak COG prior period reconciliation balance is approximately $1.9 million higher than the prior period reconciliation balance reflected in the 2009 Off Peak COG factor.

Q. What was the actual weighted average firm sales cost of gas rate for the 2009 Summer Period?

A. The weighted average cost of gas rate for the 2009 Summer Period was approximately $0.6106 per therm. This was determined by applying the actual monthly cost of gas rates for May 2009 through October 2009 to the monthly therm usage of a typical residential heating customer using 1,250 therms per year, or 318 therms for the six summer period months, for heat, hot water and cooking.

PRIOR PERIOD OVER COLLECTION

Q. Please explain the prior period over collection of 38,753.

A. The prior period over collection is detailed in the 2009 Summer Period Reconciliation Analysis included in Tab 14 of this filing. Over the 2009 Summer Period, allowable gas costs of $13,820,952 plus the prior Summer Period over collection of $(1,704,061) was more than the Gas Cost Revenue of $12,078,138 by $38,753. The net result is an ending under collection balance of $38,753 as of November 1, 2009 as shown on the 2009 Summer Period Reconciliation Analysis. Comparing the actual revenues billed and the gas costs incurred to those that the Company projected in its initial 2009 Summer Period Cost of Gas filing, the under recovery of $38,753 is the net result of the following: (i) a $9,647 decrease to interest; (ii) a 126,895 increase in prior period adjustment, (iii) a $14,901 decrease in overheads, (iv) a $31,121 disallowance in occupant billings resulting from the settlement agreement approved in DG 07-129, (v) a $3,170,794 decrease in actual gas costs compared to projections; and (vi) a $3,138,320 reduction in gas cost revenue billed compared to projections.

CUSTOMER BILL IMPACTS

Q. What is the estimated impact of the proposed firm sales cost of gas rate 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. The total bill impact for a typical residential heating customer is an increase of approximately $59, or 16.6% as compared to the average COG and LDAC for 2009 summer season. The total bill impact for a typical commercial/industrial G-41 customer is an increase of approximately $98, or 14.2% of as compared to the average COG and LDAC for 2009 summer season. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers. Please note there is small base rate bill increase for Residential heating customers ($1) and Commercial customers G-41 ($2) resulting from the August 2009 implementation of the base rates approved in DG 09-095.

OTHER ISSUES

Q. In this filing, has the Company included actual historical occupant data as specified in Section E.3 of the occupant settlement approved in DG 07-129?

A. Yes, in Tab 15, the Company has provided historical occupant data for the period November 2008 through October 2009 which details the number of open and closed occupant accounts along with detailed monthly arrearage information.

Q. Have any of the proposed changes to the Company's Natural Gas Price Risk Management Plan as described in Mr. McCauley's testimony been incorporated in the Company's proposed 2010 Off Peak COG factor?.

A. No, the Company has not included any of these changes to the Company's Natural Gas Price Risk Management Plan in its 2010 Off Peak COG filing. The changes discussed in Mr. McCauley's testimony are proposed to be applied effective with for the 2010-11 peak period.

<u>LOCAL DISTRIBUTION ADJUSTMENT CHARGE</u>

Q. Is the Company proposing any changes to the Local Distribution Adjustment Charge in this filing?

A. The Company is not proposing any changes to the LDAC in this filing. The LDAC is typically adjusted as part of the winter period cost of gas proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

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

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<u>Prefiled Testimony of Theodore Poe, Jr.</u>

March 15, 2010

Q. Please state your name, address and position with National Grid NH

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

Q. 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 requirements of Essex Gas Company, Colonial Gas Company and EnergyNorth Natural Gas, Inc. d/b/a National Grid NH.

Q. 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. Have you previously testified in regulatory proceedings?

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

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

A. The purpose of my testimony is to summarize the gas supply and transportation portfolio and the forecasted sendout requirements for National Grid NH (the "Company") for the 2010 off-peak season. This information is provided in significantly more detail in the schedules that the Company is filing.

Q. Would you describe the transportation contract portfolio that the Company now holds?

A. The Company currently holds contracts on Tennessee Gas Pipeline (106,833 MMBtu/day) and Portland Natural Gas Transmission (1,000 MMBtu/day) to provide a daily deliverability of 107,833 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. 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 71,596 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 50,000 MMBtu/day of firm supply from Tennessee's Dracut meter in Dracut, MA. This supply is delivered to the Company on two transportation contracts 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.

- 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 transportation contract portfolio that the Company now holds since the Company filed its 2009 Off Peak (Summer) Period Cost Of Gas Filing?

A. Yes, on November 1st, 2009, the Company initiated service on its Tennessee contract #72694 ("Concord Lateral") to add 30,000 MMBtu/day of deliverability from Dracut, MA to the Company's citygates. This contract was previously reviewed and approved by the Commission in Docket DG 07-101.

Next, in conjunction with a 2009/10 peak period gas supply contract with BP Canada Energy Company ("BP Canada") for supply from Dawn, Ontario, the Company entered into a Capacity Assignment and Gas Delivery Agreement with BP Canada for a term of November 1, 2009 through October 31, 2010. Under this agreement, BP Canada pays a fixed fee to the Company for the right to optimize the assets along the TransCanada path to the interconnect with Iroquois at Waddington, NY. This agreement enables the Company to extract value from this asset while retaining the capacity required to deliver the supply the Company has contracted for from Dawn.

Finally, the Company entered into an Asset Management and Gas Supply Agreement with Repsol Energy North America Corporation ("Repsol") for a term of November 1, 2009 through October 31, 2010. This arrangement is discussed in more detail later in my testimony.

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 transportation contracts are firm supplies that the Company purchases primarily in the U.S. Gulf Coast.

The Company has a supply contract with BP Gas & Power Ltd, which began on April 1, 2007, to purchase of up to 3,122 MMBtu per day at Niagara. This is a five-year contract that allows the Company monthly nomination flexibility and market-based pricing.

Otherwise, except as noted below, the Company plans to follow its traditional supply purchasing practices to refill its underground storage field capacity and to provide for any other supply requirements of its customers.

Q. Have there been any changes in the supply contract portfolio that the Company now holds since the Company submitted its 2009 Off Peak Cost Of Gas Filing?

A. Yes. During the 2009 off-peak period, the Company held a supply contract for its Dawn capacity. For the upcoming 2010 off-peak period, the Company chose not to baseload supply from Dawn, based on the projected pricing differentials between Dawn and the Company's traditional Gulf Coast supply source. Under the terms of the BP Canada agreement, the Company retains the right to call on gas at Waddington during the off-peak period if required. Although the Company has not locked in any baseload volumes from Dawn for the summer, the Company can purchase gas on a day-by-day basis or for a multi-month period if prices prove advantageous.

Additionally, after completion of the Concord Lateral project, the Company issued an Request for Proposal ("RFP") on September 29, 2009 for an Asset Management and Gas Supply Agreement effective November 1, 2009 for a term of one year for the entirety of the Company's two Tennessee transportation contracts totaling 50,000MMBtu per day from Dracut. Based on the Company's analysis, the appropriate mix of baseload and swing volume requirements by month was established, and the RFP contained two packages for bidding for the term of November 1, 2009 to October 31, 2010.

Package 1 was presented as an asset management arrangement and gas supply requirement. In order to match the two Tennessee FT-A Agreements, Package 1 was further subdivided into two agreements—one for an MDQ of 25,500 MMBtu/day with both a baseload and swing component for the months of November 2009 through May 2010 and October 2010 and the other for an MDQ of 17,000 MMBtu/day with a daily swing component for the months of November 2009 through April 2010. The delivery points for both agreements were identified as the National Grid NH citygates. As set forth in the RFP, once the delivery obligations were met, the successful bidder would retain the right to optimize the released assets, while paying a fixed fee to the Company. As a result of the RFP for Package 1, the Company entered into an Asset Management and Gas Supply Agreement with Repsol Energy North America Corporation ("Repsol") pursuant to the terms of the RFP.

Package 2 was for gas supply only, with an MDQ of up to 7,500 MMBtu/day, and was designed to be used by the Company to meet the full sendout requirements as well as meet the obligations of the Customer Choice Program with regard to migration. As a result of the RFP for Package 2, the Company entered into a supply arrangement with

Sempra Energy Trading for the months of December 2009 to March 2010 to provide for a daily swing quantity of up to 7,500 MMBtu/day.

The combination of Packages 1 and 2 provides the Company with an MDQ of up to 50,000 MMBtus.

Q. Would you describe any supplemental sources of gas supply available to the Company that are used to provide service during the off-peak period?

A. The Company has several additional sources of gas supply available to it during the off-peak period. The Company owns three LNG vaporization facilities in Concord, Manchester and Tilton that have an aggregate vaporization rate of 18,810 MMBtu/day and a combined storage capacity of 13,057 MMBtu. Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua and Tilton that have an aggregate vaporization rate of 34,600 MMBtu/day and a combined storage capacity of 100,993 MMBtu. These supplemental facilities are not normally used to provide supply service during the off-peak period, but they are available for maintaining system integrity.

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

A. As in prior cost of gas filings, the Company used projected sendout requirements and costs from its internal budgets and forecasts as a means of projecting the cost of gas for the off-peak period.

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

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements of 23,000,711 Therms over the period May 1, 2010 through October 31, 2010 under normal weather conditions. In comparison, for the prior off-peak period, the Company had forecasted normal sendout requirements of 24,063,721 Therms.

Schedule 11B shows the Company's forecasted sendout requirements 23,863,958 Therms. In comparison, the Company had forecasted design sendout requirements of 24,683,015 Therms over the period May 1, 2009 through October 31, 2009 in its 2009 Off-Peak Period filing.

In Schedule 11C, the Company summarizes the normal and design year sendout requirements, the seasonally-available contract quantities, and the calculated utilization rates of its pipeline transportation and storage contracts based on Schedules 11A and 11B.

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

A. Yes, it does.

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

Summer 2010 Cost of Gas
DG 10-______

<u>Prefiled Testimony of Stephen McCauley</u>

March 15, 2010

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen A. McCauley. My business address is 100 East Old Country Road, Hicksville, New York.

Q. What is your position with National Grid?

A. I am Director of Origination in the Energy Portfolio Management organization of National Grid Corporate Services LLC ("NGCS"). As Director, I am responsible for all financial hedging activity for the eight National Grid regulated utilities, including EnergyNorth Natural Gas, which does business under the name National Grid NH ("Company").

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

A. I graduated from the United States Merchant Marine Academy in 1984 with a Bachelor of Science degree in Marine Engineering Systems. I joined the Long Island Lighting Company ("LILCO") in 1992 as an engineer for the gas peak- shaving plants and the gas regulator and telemetering stations. In 1996, I joined LILCO's gas supply group as a trader responsible for purchasing the natural gas supply requirements for firm gas customers and the generation facilities operated by LILCO. Upon the completion of a corporate transaction in 1998, LILCO's gas supply group became part of KeySpan Corporation ("KeySpan"). In 1999, my responsibilities were changed to managing the emissions allowance portfolio and the financial hedging activities of the regulated utilities. I was promoted to my current position in 2002 and have held that position through the acquisition of KeySpan by National Grid plc.

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

A. The purpose of my testimony is to present National Grid NH's proposed modifications to its Natural Gas Price Risk Management Plan (the Plan), often referred to as its hedging strategy.

Q. Why is the Company proposing to revise the Natural Gas Price Risk Management Plan?

A. The Company is proposing to revise the Plan for multiple reasons. First, participation percent changes in the Company's Fixed Price Option (FPO) program have caused the percent hedged for the firm sales customers under the Risk Management Plan to be higher than originally anticipated. Second, the Company believes it would be beneficial to adopt an alternative methodology to determining the financial volume to be hedged. Third, the Company is seeking to eliminate the storage injection hedges because they essentially are a hedge of a hedge and have a de minimis affect on winter price volatility reduction. Fourth, the increased cost of collateral required for transactions executed under the Plan has resulted in an additional cost that needs to be recovered through the Cost of Gas rate. The revised Natural Gas Price Risk Management Plan that the Company is proposing be adopted is included with my testimony as Attachment SAM -1.

Q. How has the FPO program affected the percent of gas purchases hedged under the Plan?

A. From the 1999-2000 winter season to the 2004-2005 winter season, enrollment in the FPO program increased from 9% of firm sales customers to 30%. In order to ensure the Company adequately hedged enough gas for both FPO and non-FPO customers under the Plan, the Company hedged 67.5% of the forecasted baseload purchases. This percent assumed an FPO hedge of 35% of firm sales volumes and an additional 32.5% of firm sales volumes for the non-FPO customers. Since the FPO price calculation was changed in 2005, the participation percentage in the FPO program has dropped to 15%-16%. This drop in FPO participation has resulted in a portion of the FPO-hedged volumes being allocated to the non-FPO firm rate customers, and as a result the percentage of gas purchases hedged for the non-FPO customers was slightly higher than anticipated. Given the lower participation rates that the Company has been experiencing in the FPO, we are proposing that the Company hedge a lower percentage of its baseload purchases to meet its FPO requirements than is required under the current Risk Management Plan.

Q. Is the Company concerned that the FPO participation will once again approach 30%?

A. Although the Company can not guarantee that the participation will not increase, the Company believes the reason for the higher level of participation in the FPO prior to 2005 was due to the Company having an FPO offer price that was disconnected from the non-FPO price during the FPO enrollment period. The methodology for calculating the FPO price now ensures that the FPO price will be slightly higher than the forecasted non-FPO price at the time of the FPO enrollment period.

Q. You indicated that the Company is also proposing a change to the methodology for calculating the monthly hedging volumes . Please describe this change.

A. In the current hedging plan, the Company hedges 67.5% of the forecasted baseload purchases, but no supplies are hedged for forecasted daily swing purchases. The Company originally only included baseload volumes because these volumes were priced at the First of Month (FOM) published indices, which are highly correlated to the NYMEX swaps and option transactions and therefore are very effective hedges. The Company is now proposing to determine the financial hedge volume based on the total firm sales forecast, including forecasted storage withdrawals and fixed price physical purchases. The goal is to hedge two-thirds of the forecasted total sales volume in December, January, February and March. In this period the hedge volume would be a combination of storage withdrawals and financial hedges. In the months of November and April the Company would hedge 50% of the forecasted firm sales load since there are no planned storage withdrawals in these months. The hedge percentage drops to 40% in October and May since there is no FPO program in these months. These changes will reduce the financial hedge volume by approximately 6%. Attachment SAM-2 shows the actual planned hedge volumes for the 2010 – 2011 peak period with and without the Company's proposed changes to the risk management plan.

Q. Why is the Company proposing to eliminate the storage injection hedges?

A. The goal of the Natural Gas Price Risk Management Plan is to reduce gas cost volatility in the winter season. The existing storage injection hedge strategy requires hedging 20% of the storage capacity. The Company is proposing to eliminate the storage injection hedge for two reasons. Since the price of storage is known prior to the winter season it is already a hedge against winter price volatility and therefore the storage hedge strategy is a hedge of a hedge. The 20% storage hedge changes the volatility by less than 0.5% and therefore is virtually ineffective. In addition, eliminating the storage hedges also has the potential to reduce costs incurred from increased collateral requirements, which have become material, as I discuss below.

Q. Why is the Company requesting authorization to recover costs and credits due to collateral requirements?

A. The Company is requesting recovery of collateral requirement costs due to changes that have occurred in the financial markets and the continued volatility of the gas markets. In the past several years, credit has been tightening and therefore market participants have been negotiating lower credit thresholds in the master agreements governing gas purchasing and derivative transactions. In addition, the extreme volatility of prices in 2008 and 2009 severely tested these credit thresholds, requiring the Company to post additional collateral. The master agreements require that the party holding collateral must pay the party issuing collateral interest based on an overnight published market fund rate. Interest is required to be paid because the collateral is effectively an advanced partial payment on a future obligation. In order to post cash collateral, the Company must itself borrow funds at a short term rate that exceeds the interest rate for which it is credited by the counter party. Similarly, when the Company receives collateral, it has the use of those funds and pays interest at a rate that is lower than its own short term borrowing rate. The Company is recommending a methodology to include this cost or benefit of posting or collecting collateral in its COG rates.

Q. How is it determined if the Company is required to post collateral or receive collateral from a counter party?

A. At the end of each day the Company and the counter party each separately determine the market value of all of the open financial hedge positions based on that days settlement prices. (This value is referred to as the mark to market value, or MTM.) If the market prices have risen such that the total MTM value of the Company's position exceeds the credit threshold established in the ISDA (the master agreement) then the counter party must provide collateral, in most cases cash, to the Company such that the MTM exposure less the collateral posted does not exceed the credit threshold. If the market prices have dropped such that the total MTM value of the Company's aggregate positions exceeds the credit threshold in the ISDA then the Company must post collateral to the counter party such that the MTM exposure less the collateral posted does not exceed the credit threshold.

Q. How does the Company plan on calculating the cost of collateral for purposes of the cost of gas?

A. On any day that the Company has either outstanding collateral posted or is in receipt of collateral, the Company will calculate the impact as follows. The amount of the outstanding collateral given or received will be multiplied by the difference between the interest rate established in the master agreement and the Company's short term borrowing rate. If the Company is posting collateral with a counter party then the amount will be applied as a cost to be recovered through the COG. If the Company is in receipt of collateral, then the amount will be applied as a credit to the COG.

Q. Can you please provide an example of how the financial hedges and incremental carrying costs on associated hedges will be recovered from ratepayers through the COG mechanism?

A. Yes, the simplest way to explain is through an example. Let me first review how the Company recovers the hedge payment. Assume in February 2010 the Company entered into a financial hedge agreement with Company A for 10,000 Dktherms at a price of $4.00/Dktherm for the month of November 2010. Assume in November 2010, the actual cost of gas for the month is $3.00/Dktherm. In November 2010, the Company will pay its supplier for 10,000 Dktherms at $3.00/unit or $30,000 and will then pay Company A $10,000 (10,000 Dktherm * ($4.00-$3.00)). So in November 2010, the Company will include $40,000 in its COG factor to reflect the cost of these two transactions. Now as explained above, due to the tightening of the credit market and the recent volatility in gas prices, these financial hedging agreements now require collateral payments under certain specified conditions. So if in May 2010 the NYMEX futures strip for natural gas indicates that the price of gas for November 2010 will be $2.00, then the MTM of this position is 10,000 Dktherm *($4.00 - $2.00) = $20,000. The Company will be required to put up collateral in the amount of 10,000 Dktherm * ($4.00 - $2.00) = $20,000 (i.e., the difference between the market value of the gas for which the Company has contracted and the value that the Company is contractually obligated to pay). If we assume the credit threshold is $15,000 then the Company will be required to put up collateral in the amount of (MTM – Credit Threshold) $20,000 - $15,000 = $5,000. To post this collateral, the Company borrows this amount, incurring interest at its short term borrowing rate. Although the agreement with the counter party requires the counter party to credit the Company in November for this collateral payment plus associated interest, the interest paid to the Company is less than the interest expense the Company incurs to borrow this money. The difference between the interest paid to the Company and the interest expense incurred by the Company would be included as a recoverable gas cost for the month of November under the Company's proposal. Similarly, if the transaction were reversed, so that the Company paid interest on funds received as collateral, thereby relieving it of an incremental amount of short term borrowing costs, the Company would credit customers for the appropriate month's gas costs.

Q. Does the Company plan to file to recover past collateral costs?

A. No.

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

A. Yes, it does.

EnergyNorth Natural Gas, Inc.

d/b/a National Grid NH

Natural Gas Price Risk Management Plan

INTRODUCTION

National Grid NH ("Company") has been managing the volatility of it natural gas commodity costs since the late 1990's and is currently managing the volatility under the Natural Gas Price Risk Management Plan approved in order DG-05-127 Without such a plan the firm sales customers' cost of gas would have fluctuated similar to the volatility seen in the NYMEX futures contract because a substantial portion of the Company's gas supply is priced based on market indices. The natural gas market continues to see the same volatility of prices that prompted the Company to originally institute a risk management plan, and therefore the Company supports continuation of the current risk management plan with a few modifications. This statement of the plan is intended to supersede all prior versions that have previously been adopted. The plan uses various financial risk management tools and underground storage in order to provide more price stability in the cost of gas to firm sales customers and to fix the cost of gas for participants in the Company's Fixed Price Option ("FPO") Program[1]. It is not intended to achieve reductions in customers' overall gas costs.

PLAN TERM

This Plan is intended to become effective for the 2011 – 2012 peak period[2], upon approval by the

[1] See the "EnergyNorth Natural Gas, Inc. d/b/a National Grid New Hampshire Fixed Price Option Program" approved by the New Hampshire Public Utilities Commission.
[2] The plan also covers gas purchased for the months of May and October, which are the first and last month of the off-peak period.

New Hampshire Public Utilities Commission. Continued effectiveness of the plan shall thereafter be subject to review and approval by the Company's Energy Procurement Risk Management Committee (EPRMC) or its successor or such person or persons to whom the EPRMC delegates its authority.

GUIDELINES

Risk Management Tools

The Company may use derivatives (swaps, call and put options) and/or physical supplies to hedge the price for a portion of its gas supply portfolio for the period from October through May of each year. The Company will use a combination of financial hedges, storage withdrawals and fixed price contracts to hedge a monthly target hedge percentage. The purchase and sale of derivatives may be either physical or financial.

Volume Guidelines

The peak period hedge target volume will be determined using the specific monthly hedge percentages listed below as a portion of the Company's total firm sales forecast for each month listed. Overall, the Company will not hedge less than 30% or more than 80% of the forecasted firm sales load in the peak period. The total volume hedged shall include financial, fixed price contracts and storage volumes and will initially be a percentage of the most recent firm sales forecast, as of March 1st of each year, prior to the start of the execution of the strategy for a given period. Hedge volumes will be revised based on the most recent firm sales forecast as of October 1st. If the hedge volume changes by more than 5%, based on the new forecast, then the remaining execution volumes will be adjusted proportionately for the remainder of the term of the strategy starting in November. The total financial hedge volume will be calculated as the firm sales volumes multiplied by the volume target below minus forecasted storage withdrawals minus fixed priced physical contracts.

The following monthly hedge percentages will be used to set the total hedge volume target:

- October 40%
- November 50%
- December 66%
- January 66%
- February 66%
- March 66%
- April 50%
- May 40%

At a minimum the Company will hedge the forecasted financial volumes according to the following <u>execution timing targets</u>, with a tolerance in each month of plus or minus 2%:

- August 1 (15 months prior to the winter season) 19% of the financial volumes
- November 1 (15 months prior to the winter season) 38% of the financial volumes
- February 1 57% of the financial volumes
- May 1 76% of the financial volumes
- August 1 95% of the financial volumes
- September 1 100% of the financial volumes

<u>Transaction Execution Guidelines</u>

For each October through May period, a specific hedging strategy will be presented and approved at a meeting of the Company's Commodity Management Committee (CMC) and shall then be presented to the EPRMC for review and approval unless the EPRMC has previously delegated its authority to the CMC. The hedging strategy shall address the types of transactions to be entered into, execution timing and option premium expenditures.

Upon execution of a transaction, the transaction shall be entered into the Company's risk and transaction management system. A daily transaction report shall be generated and must be reviewed before the end of the day by the trader. Transactions shall be confirmed with the counterparty by the Company's mid-office and the deal shall be locked in the transaction management system.

<u>Reporting</u>

A daily mark to market (MTM) report shall be generated and compared to the counter parties' respective MTM reports. The MTM positions shall be compared against each counter party's credit threshold established in the ISDA master agreement. If the MTM value for all transactions with a particular counter party exceeds the credit threshold for the relevant party, then the counter party must post collateral to keep the credit exposure within the allowable credit threshold limit. If the Company's total MTM exposure exceeds the credit threshold established in the relevant ISDA master agreement, the Company will be required to post collateral for the benefit of the counter party. Daily posting of collateral by either party will continue until the credit exposure is within the prescribed credit thresholds.

A weekly report shall be generated summarizing the transactions and the status of the hedging targets. A monthly report summarizing the hedging strategy shall be distributed at the monthly CMC and EPRMC meetings.

Costs

The Company will execute the financial transactions using bilateral Over the Counter (OTC) swaps and options through ISDA master agreements with various investment grade counter parties. There are currently no specific transaction costs associated with OTC transactions except for potential margin calls when the MTM exposure exceeds the credit threshold. The Company may decide in the future to use NYMEX future contracts to hedge gas costs. Such contracts would require the Company to incur transaction fees as a necessary and reasonable cost of entering into such transactions.

The cost or credit associated with posting collateral will be calculated daily based on the outstanding margin posted each day multiplied by the percentage difference between then interest rate established in the relevant master agreement and the Company's monthly short term borrowing rate.

Option premiums associated with puts and calls shall be limited to $2 million dollars for each winter strategy.

REGULATORY TREATMENT

The Company will credit the Cost of Gas (the "COG") for the entire amount of the actual premiums received from the sale of options and for credit associated with collateral collected. Additionally, the actual premiums paid for the purchase of options, transaction fees, and costs associated with posting collateral will be charged entirely to the COG. These costs will be charged to the COG period for which an option was purchased and sold (i.e., options pertaining to the months of November through April will be charged to the peak period COG). The Company anticipates that any premiums received from the sale of put options will reduce the cost of the program. Differences between the market price of the physical purchase of natural gas and the price of gas hedged through the purchase and/or sale of options will be deemed to be a recoverable cost of gas for the period hedged.

Any derivative settlement payables or receivables associated with the physical purchase of natural gas will be deemed to be a recoverable cost of gas for the period hedged.

PROCEDURES AND CONTROLS

All hedging strategies approved by the Commodity Management Committee and the Energy Procurement Risk Management Committee and must conform with the National Grid Treasury Policy – US Energy Commodity Risk section policy and procedures.

Base Case Normal Year: May 2010 - May 2011
(MMBtu)

Volumes to sales customers only

	10/2010	11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	Total
Firm Sales	692,984	1,122,105	1,664,324	2,008,769	1,626,827	1,392,237	816,942	476,342	*9,800,530*
Storage Withdrawals	2,463	2,381	268,516	534,226	343,170	548,851	2,466	2,463	*1,704,536*
Baseload purchases	640,246	735,146	1,394,702	1,453,541	1,292,840	768,732	576,230	547,593	*7,409,031*
Firm Sales less Storage Withdrawals	690,521	1,119,724	1,395,808	1,474,543	1,283,657	843,386	814,476	473,879	*8,095,994*
Total Hedge Target %	40%	50%	66%	66%	66%	66%	50%	40%	
Total Hedge Target Volume (includes storage)	277,194	561,053	1,098,454	1,325,788	1,073,706	918,876	408,471	190,537	*5,854,078*
Financial Hedge Target (proposed)	274,731	558,672	829,938	791,561	730,536	370,025	406,005	188,074	*4,149,542*
Current Hedge volume	339,000	367,000	899,000	1,037,000	1,010,000	627,000	102,000	53,000	*4,434,000*
Financial Hedge Change (dt)	-64,269	191,672	-69,062	-245,439	-279,464	-256,975	304,005	135,074	-284,458

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

Filed Tariff Sheets

Proposed Twelfth Revised Page 1
Check Sheet

Proposed Twelfth Revised Page 3
Check Sheet

Proposed Twelfth Revised Page 76
Firm Rate Schedules

Proposed Second Revised Page 86
Anticipated Cost of Gas

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

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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	$ 1.0230	$ 0.0410	$ 1.2147	$ 0.1507	$ 0.7784	$ 0.0410	$ 0.9701
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	$ 1.0230	$ 0.0404	$ 1.3101	$ 0.2467	$ 0.7784	$ 0.0404	$ 1.0655
All therms over the first block per month at	$ 0.1859	$ 1.0230	$ 0.0404	$ 1.2493	$ 0.1859	$ 0.7784	$ 0.0404	$ 1.0047
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	$ 1.0230	$ 0.0404	$ 1.1621	$ 0.0987	$ 0.7784	$ 0.0404	$ 0.9175
All therms over the first block per month at	$ 0.0744	$ 1.0230	$ 0.0404	$ 1.1378	$ 0.0744	$ 0.7784	$ 0.0404	$ 0.8932
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	$ 1.0232	$ 0.0194	$ 1.3400	$ 0.2974	$ 0.7788	$ 0.0194	$ 1.0956
All therms over the first block per month at	$ 0.1934	$ 1.0232	$ 0.0194	$ 1.2360	$ 0.1934	$ 0.7788	$ 0.0194	$ 0.9916
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	$ 1.0232	$ 0.0194	$ 1.3068	$ 0.2642	$ 0.7788	$ 0.0194	$ 1.0624
All therms over the first block per month at	$ 0.1745	$ 1.0232	$ 0.0194	$ 1.2171	$ 0.1745	$ 0.7788	$ 0.0194	$ 0.9727
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	$ 1.0232	$ 0.0194	$ 1.2017	$ 0.0728	$ 0.7788	$ 0.0194	$ 0.8710
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	$ 1.0225	$ 0.0194	$ 1.2347	$ 0.1928	$ 0.7778	$ 0.0194	$ 0.9900
All therms over the first block per month at	$ 0.1245	$ 1.0225	$ 0.0194	$ 1.1664	$ 0.1245	$ 0.7778	$ 0.0194	$ 0.9217
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	$ 1.0225	$ 0.0194	$ 1.1924	$ 0.1106	$ 0.7778	$ 0.0194	$ 0.9078
All therms over the first block per month at	$ 0.1021	$ 1.0225	$ 0.0194	$ 1.1440	$ 0.0637	$ 0.7778	$ 0.0194	$ 0.8609
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	$ 1.0225	$ 0.0194	$ 1.1506	$ 0.0520	$ 0.7778	$ 0.0194	$ 0.8492
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	$ 1.0225	$ 0.0194	$ 1.0774	$ 0.0192	$ 0.7778	$ 0.0194	$ 0.8164

Anticipated Cost of Gas

PERIOD COVERED: SUMMER PERIOD, MAY 1, 2010 THROUGH OCTOBER 31, 2010
(REFER TO TEXT IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 3,253,976	
Supply Costs:	12,301,578	
Storage Gas:		
Demand, Capacity:	$ -	
Commodity Costs:	-	
Produced Gas:	$ 77,045	
Hedged Contract (Savings)/Loss	$ 630,394	
Unadjusted Anticipated Cost of Gas		$ 16,262,993
Adjustments:		
Prior Period (Over)/Under Recovery (as of October 31, 2009)	$ 38,753	
Interest	9,800	
Prior Period Adjustments	-	
Broker Revenues	-	
Refunds from Suppliers	-	
Fuel Financing	-	
Transportation CGA Revenues	-	
Interruptible Sales Margin	-	
Capacity Release Margin	-	
Hedging Costs	-	
Fixed Price Option Administrative Costs	-	
Total Adjustments		48,553
Total Anticipated Direct Cost of Gas		$ 16,311,546
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Anticipated Direct Cost of Gas 05/01/10 - 10/31/10)	$ 16,262,993	
Lead Lag Days	10.18	
Prime Rate	3.25%	
Working Capital Percentage	0.091%	
Working Capital	$ 14,741	
Plus: Working Capital Reconciliation (Acct 142.40)	(93,103)	
Total Working Capital Allowance		$ (78,361)
Bad Debt:		
Total Anticipated Direct Cost of Gas 05/01/10 - 10/31/10)	$ 16,262,993	
Less: Refunds	-	
Plus: Total Working Capital	(78,361)	
Plus: Prior Period (Over)/Under Recovery	38,753	
Subtotal	$ 16,223,385	
Bad Debt Percentage	2.40%	
Bad Debt Allowance	$ 389,361	
Plus: Bad Debt Reconciliation (Acct 175.54)	51,447	
Total Bad Debt Allowance		440,808
Production and Storage Capacity		-
Miscellaneous Overhead (05/01/10 - 10/31/10)	$ 25,381	
Times Summer Sales	21,908	
Divided by Total Sales	105,710	
Miscellaneous Overhead		5,260
Total Anticipated Indirect Cost of Gas		$ 367,707
Total Cost of Gas		$ 16,679,253

Issued: March 15, 2010
Effective: May 1, 2010

Issued: By______________________
Nickolas Stavropoulos
Title: President

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

(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$ 16,311,546		
Projected Prorated Sales (05/01/10 - 10/31/10)	21,428,146		
Direct Cost of Gas Rate		$ 0.7612	per therm
Demand Cost of Gas Rate	$ 3,253,976	$ 0.1519	per therm
Commodity Cost of Gas Rate	13,009,017	$ 0.6071	per therm
Adjustment Cost of Gas Rate	48,553	$ 0.0023	per therm
Total Direct Cost of Gas Rate	$ 16,311,546	$ 0.7612	per therm
Total Anticipated Indirect Cost of Gas	$ 367,707		
Projected Prorated Sales (05/01/10 - 10/31/10)	21,428,146		
Indirect Cost of Gas		$ 0.0172	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/10		**$ 0.7784**	**per therm**
RESIDENTIAL COST OF GAS RATE - 05/01/10	**COGsr**	**$ 0.7784**	**/therm**
	Maximum (COG + 25%)	$ 0.9730	
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10	**COGsl**	**$ 0.7778**	**/therm**

Average Demand Cost of Gas Rate Effective 05/01/10	$ 0.1519		
'Times: Low Winter Use Ratio (Summer)	0.9944	Maximum (COG + 25%)	$ 0.9723
Times: Correction Factor	1.00128		
Adjusted Demand Cost of Gas Rate	$ 0.1512		
Commodity Cost of Gas Rate	$ 0.6071		
Adjustment Cost of Gas Rate	$ 0.0023		
Indirect Cost of Gas Rate	$ 0.0172		
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.7778		

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10	**COGsh**	**$ 0.7788**	**/therm**

Average Demand Cost of Gas Rate Effective 05/01/10	$ 0.1519		
'Times: High Winter Use Ratio (Summer)	1.0008	Maximum (COG + 25%)	$ 0.9735
Times: Correction Factor	1.00128		
Adjusted Demand Cost of Gas Rate	$ 0.1522		
Commodity Cost of Gas Rate	$ 0.6071		
Adjustment Cost of Gas Rate	$ 0.0023		
Indirect Cost of Gas Rate	$ 0.0172		
Adjusted Com/Ind High Winter Use Cost of Gas Rate	$ 0.7788		

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83	Original
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86	~~First~~ Second Revised
87	~~Ninth~~ Tenth Revised
88	First Revised
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91	First Revised
92	First Revised
93	Original
94	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	$ 1.0230	$ 0.0410	$ 1.2147	$ 0.1507	$ 0.7784	$ 0.0410	$ 0.9701
					~~$ 0.1507~~	~~$ 0.5272~~	~~$ 0.0254~~	~~$ 0.7033~~
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	$ 1.0230	$ 0.0404	$ 1.3101	$ 0.2467	$ 0.7784	$ 0.0404	$ 1.0655
					~~$ 0.2467~~	~~$ 0.5272~~	~~$ 0.0260~~	~~$ 0.7999~~
All therms over the first block per month at	$ 0.1859	$ 1.0230	$ 0.0404	$ 1.2493	$ 0.1859	$ 0.7784	$ 0.0404	$ 1.0047
					~~$ 0.1859~~	~~$ 0.5272~~	~~$ 0.0260~~	~~$ 0.7391~~
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	$ 1.0230	$ 0.0404	$ 1.1621	$ 0.0987	$ 0.7784	$ 0.0404	$ 0.9175
					~~$ 0.0987~~	~~$ 0.5272~~	~~$ 0.0260~~	~~$ 0.6519~~
All therms over the first block per month at	$ 0.0744	$ 1.0230	$ 0.0404	$ 1.1378	$ 0.0744	$ 0.7784	$ 0.0404	$ 0.8932
					~~$ 0.0744~~	~~$ 0.5272~~	~~$ 0.0260~~	~~$ 0.6276~~
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	$ 1.0232	$ 0.0194	$ 1.3400	$ 0.2974	$ 0.7788	$ 0.0194	$ 1.0956
					~~$ 0.2974~~	~~$ 0.5277~~	~~$ 0.0278~~	~~$ 0.8529~~
All therms over the first block per month at	$ 0.1934	$ 1.0232	$ 0.0194	$ 1.2360	$ 0.1934	$ 0.7788	$ 0.0194	$ 0.9916
					~~$ 0.1934~~	~~$ 0.5277~~	~~$ 0.0278~~	~~$ 0.7489~~
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	$ 1.0232	$ 0.0194	$ 1.3068	$ 0.2642	$ 0.7788	$ 0.0194	$ 1.0624
					~~$ 0.2642~~	~~$ 0.5277~~	~~$ 0.0278~~	~~$ 0.8197~~
All therms over the first block per month at	$ 0.1745	$ 1.0232	$ 0.0194	$ 1.2171	$ 0.1745	$ 0.7788	$ 0.0194	$ 0.9727
					~~$ 0.1745~~	~~$ 0.5277~~	~~$ 0.0278~~	~~$ 0.7300~~
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	$ 1.0232	$ 0.0194	$ 1.2017	$ 0.0728	$ 0.7788	$ 0.0194	$ 0.8710
					~~$ 0.0728~~	~~$ 0.5277~~	~~$ 0.0278~~	~~$ 0.6283~~
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	$ 1.0225	$ 0.0194	$ 1.2347	$ 0.1928	$ 0.7778	$ 0.0194	$ 0.9900
					~~$ 0.1928~~	~~$ 0.5257~~	~~$ 0.0278~~	~~$ 0.7463~~
All therms over the first block per month at	$ 0.1245	$ 1.0225	$ 0.0194	$ 1.1664	$ 0.1245	$ 0.7778	$ 0.0194	$ 0.9217
					~~$ 0.1245~~	~~$ 0.5257~~	~~$ 0.0278~~	~~$ 0.6780~~
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	$ 1.0225	$ 0.0194	$ 1.1924	$ 0.1106	$ 0.7778	$ 0.0194	$ 0.9078
					~~$ 0.1106~~	~~$ 0.5257~~	~~$ 0.0278~~	~~$ 0.6641~~
All therms over the first block per month at	$ 0.1021	$ 1.0225	$ 0.0194	$ 1.1440	$ 0.0637	$ 0.7778	$ 0.0194	$ 0.8609
					~~$ 0.0637~~	~~$ 0.5257~~	~~$ 0.0278~~	~~$ 0.6172~~
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	$ 1.0225	$ 0.0194	$ 1.1506	$ 0.0520	$ 0.7778	$ 0.0194	$ 0.8492
					~~$ 0.0520~~	~~$ 0.5257~~	~~$ 0.0278~~	~~$ 0.6055~~
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	$ 1.0225	$ 0.0194	$ 1.0774	$ 0.0192	$ 0.7778	$ 0.0194	$ 0.8164
					~~$ 0.0192~~	~~$ 0.5257~~	~~$ 0.0278~~	~~$ 0.5727~~

Anticipated Cost of Gas
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2010 THROUGH OCTOBER 31, 2010
~~**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)~~	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 6,919,850~~		$ 3,253,976	
Supply Costs:	~~$ 48,398,041~~		12,301,578	
Storage Gas:				
Demand, Capacity:	~~1,097,023~~		-	
Commodity Costs:	~~7,583,539~~		-	
Produced Gas:	~~657,484~~		77,045	
Hedged Contract Savings	~~11,627,343~~		630,394	
Hedge Underground Storage Contract (Savings)/Loss	~~1,868,333~~		-	
Unadjusted Anticipated Cost of Gas		~~$ 78,151,613~~		$ 16,262,993
Adjustments:				
Prior Period (Over)/Under Recovery (as of ~~October 1, 2009~~ May 1, 2010)	~~$ 935,450~~		$ 38,753	
Interest	~~49,971~~		9,800	
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 Margin	~~(635,528)~~		-	
Hedging Costs	~~-~~		-	
Fixed Price Option Administrative Costs	~~40,691~~		-	
Total Adjustments		~~(281,067)~~		48,553
Total Anticipated Direct Cost of Gas		~~$ 77,870,546~~		$ 16,311,546
Anticipated Indirect Cost of Gas				
Working Capital:				
Total anticipated Direct Cost of Gas ~~(5/01/2009 - 10/31/2009)~~(11/01/09 - 04/30/10)	~~$ 78,151,613~~		$ 16,262,993	
Lead Lag Days	~~10.18~~		10.18	
Prime Rate	~~3.25%~~		3.25%	
Working Capital Percentage	~~0.091%~~		0.091%	
Working Capital	~~70,840~~		$ 14,741	
Plus: Working Capital Reconciliation ~~(Acct 142.40)~~ (Acct 142.20)	~~(63,719)~~		(93,103)	
Total Working Capital Allowance		~~$ 7,121~~		$ (78,361)
Bad Debt:				
Total anticipated Direct Cost of Gas ~~(5/01/2009 - 10/31/2009)~~(11/01/09 - 04/30/10)	~~$ 78,151,613~~		$ 16,262,993	
Less: Refunds	-		-	
Plus: Total Working Capital	~~7,121~~		(78,361)	
Plus: Prior Period (Over)/Under Recovery	~~935,450~~		38,753	
Subtotal	~~$ 79,094,183~~		$ 16,223,385	
Bad Debt Percentage	~~2.54%~~		2.40%	
Bad Debt Allowance	~~2,008,992~~		$ 389,361	
Plus: Bad Debt Reconciliation ~~(Acct 175.54)~~ (Acct 175.52)	~~(212,161)~~		51,447	
Total Bad Debt Allowance		~~1,796,831~~		440,808
Production and Storage Capacity		~~1,749,387~~		-
Miscellaneous Overhead ~~(5/01/2009 - 10/31/2009)~~ (11/01/09 - 4/30/10)	~~$ 25,381~~		$ 25,381	
Times ~~Summer~~ Winter Sales	~~83,802~~		21,908	
Divided by Total Sales	~~105,710~~		105,710	
Miscellaneous Overhead		~~20,121~~		5,260
Total Anticipated Indirect Cost of Gas		~~$ 3,573,460~~		$ 367,707
Total Cost of Gas		~~$ 81,444,006~~		$ 16,679,253

Issued: ~~November 12, 2009~~ March 15, 2010 | Issued: By_______________
Effective: ~~November 1, 2009~~ May 1, 2010 | Nickolas Stavropoulos
Title: President

~~Issued in compliance with NHPUC Order No. 25,032 dated October 29, 2009 in Docket No. DG 09-162.~~

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2010 THROUGH OCTOBER 31, 2010
~~**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)~~	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 77,870,546~~		$ 16,311,546		
Projected Prorated Sales ~~(10/01/09 - 04/30/2010)~~ (05/01/10 - 10/31/10)	~~84,282,098~~		21,428,146		
Direct Cost of Gas Rate		~~0.9239~~		$ 0.7612	per therm
Demand Cost of Gas Rate	~~$ 8,016,873~~	~~0.0951~~	$ 3,253,976	$ 0.1519	
Commodity Cost of Gas Rate	~~70,134,740~~	~~0.8321~~	13,009,017	$ 0.6071	
Adjustment Cost of Gas Rate	~~(281,067)~~	~~(0.0033)~~	48,553	$ 0.0023	
Total Direct Cost of Gas Rate	~~$ 77,870,546~~	~~0.9239~~	$ 16,311,546	$ 0.7612	
Total Anticipated Indirect Cost of Gas	~~$ 3,573,460~~		$ 367,707		
Projected Prorated Sales ~~(10/01/09 - 04/30/2010)~~ (05/01/10 - 10/31/10)	~~84,282,098~~		21,428,146		
Indirect Cost of Gas		~~$ 0.0424~~		$ 0.0172	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/10				$ 0.7784	per Therm
~~**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09**~~		~~$ 0.9663~~			

RESIDENTIAL COST OF GAS RATE - 05/01/10	COGsr	$ 0.7784	/therm
~~**RESIDENTIAL COST OF GAS RATE - 11/01/09**~~	~~COGsr~~	~~$ 0.9663~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ (0.0424)~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 12/01/2009**~~	~~COGsr~~	~~$ 0.9239~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ (0.0264)~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 1/1/2010**~~	~~COGsr~~	~~$ 0.8975~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ 0.0180~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 2/1/2010**~~	~~COGsr~~	~~$ 0.9155~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ 0.1075~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE - 3/1/2010**~~	~~COGsr~~	~~$ 1.0230~~	~~/therm~~
Maximum	(COG + 25%)	~~$ 1.2079~~ $ 0.9730	

COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10	COGsl	$ 0.7778	/therm
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09**~~	~~COGsl~~	~~$ 0.9658~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ (0.0424)~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 12/01/2009**~~	~~COGsl~~	~~$ 0.9234~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ (0.0264)~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 1/01/2010**~~	~~COGsl~~	~~$ 0.8970~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ 0.0180~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 2/01/2010**~~	~~COGsl~~	~~$ 0.9150~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ 0.1075~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE - 3/01/2010**~~	~~COGsl~~	~~$ 1.0225~~	~~/therm~~

Average Demand Cost of Gas Rate Effective ~~11/01/09~~ 05/01/2010	~~$ 0.0951~~	$ 0.1519	Maximum	(COG + 25%)	~~$ 1.2073~~ $ 0.9723
Times: Low Winter Use Ratio (Summer)	~~0.9944~~	0.9944			
Times: Correction Factor	~~1.00080~~	1.00128			
Adjusted Demand Cost of Gas Rate	~~$ 0.0946~~	$ 0.1512			
Commodity Cost of Gas Rate	~~$ 0.8321~~	$ 0.6071			
Adjustment Cost of Gas Rate	~~(0.0033)~~	0.0023			
Indirect Cost of Gas Rate	~~0.0424~~	0.01720			
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 0.9658~~	$ 0.7778			

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10	COGsh	$ 0.7788	/therm
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/09**~~	~~COGsh~~	~~$ 0.9665~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ (0.0424)~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 12/01/2009**~~	~~COGsh~~	~~$ 0.9241~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ (0.0264)~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 1/01/2010**~~	~~COGsh~~	~~$ 0.8977~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ 0.0180~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 2/01/2010**~~	~~COGsh~~	~~$ 0.9157~~	~~/therm~~
~~Change in rate due to change in under/over recovery~~		~~$ 0.1075~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE - 3/01/2010**~~	~~COGsh~~	~~$ 1.0232~~	~~/therm~~

Average Demand Cost of Gas Rate Effective ~~11/01/09~~ 05/01/2010	~~$ 0.0951~~	$ 0.1519	Maximum	(COG + 25%)	~~$ 1.2081~~ $ 0.9735
Times: High Winter Use Ratio (Summer)	~~1.0008~~	1.0008			
Times: Correction Factor	~~1.00080~~	1.00128			
Adjusted Demand Cost of Gas Rate	~~$ 0.0953~~	$ 0.1522			
Commodity Cost of Gas Rate	~~$ 0.8321~~	$ 0.6071	Minimum		
Adjustment Cost of Gas Rate	~~$ (0.0033)~~	$ 0.0023	Maximum		
Indirect Cost of Gas Rate	~~$ 0.0424~~	$ 0.0172			
Adjusted Com/Ind High Winter Use Cost of Gas Rate	~~$ 0.9665~~	$ 0.7788			

Issued: ~~February 22, 2010~~ March 15, 2010
Effective: ~~March 1, 2010~~ May 1, 2010

Issued: By________________________
Nickolas Stavropoulos
Title: President

~~Issued in compliance with NHPUC Order No. 25,032 dated October 29, 2009 in Docket No. DG 09-162.~~

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

REDACTED VERSION

Table of Contents

Ln	(a)	Reference (b)		OP 10 May - Oct (c)
1	**ENERGY NORTH NATURAL GAS, INC.**			
2	**d/b/a National Grid NH**			
3	**Off Peak 2010 Summer Cost of Gas Filing**			
4	**Summary**			
5				OP 10
6		Reference		May - Oct
7	(a)	(b)		(c)
8				
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (j), ln 43	$	3,253,976
12	Supply Costs	Sch. 6, col (i), ln 44		12,301,578
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (j), ln 58	$	-
16	Commodity Costs:	Sch. 6, col (i), ln 47		-
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	77,045
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	630,394
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (g), ln 199		
22				
23	**Total Unadjusted Cost of Gas**		$	16,262,993
24				
25	**Adjustments:**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 26	$	38,753
28	Interest 05/01/10 - 10//31/10	Sch. 3, col (q) ln 190		9,800
29	Prior Period Adjustments	Sch. 4, ln 22 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 22 col (c)		-
31	Broker Revenues	Sch. 4, ln 22 col (d)		-
32	Fuel Financing	Sch. 4, ln 22 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 22 col (f)		-
34	Interruptible Sales Margin	Sch. 4, ln 22 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 22 col (h) + col (i)		-
36	Hedging Costs	Sch. 4, ln 22 col (j)		-
37	FPO Premium - Collection			
38	Fixed Price Option Administrative Costs	Sch. 4, ln 22 col (k)		-
39				
40	**Total Adjustments**		$	48,553
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	16,311,546
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Anticipated Direct Cost of Gas	Ln 23	$	16,262,993
47	Lead Lag Days			10.18
48	Prime Rate			3.25%
49	Working Capital Percentage	per GTC 16(f)		0.091%
50	Working Capital	ln 46 * ln 49		14,741
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 89		(93,103)
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	(78,361)
54				
55	**Bad Debt**			
56	Total Anticipated Direct Cost of Gas	ln 46	$	16,262,993
57	Less Refunds			-
58	Plus Working Capital	ln 53		(78,361)
59	Plus Prior Period (Over) Under Recovery	ln 27		38,753
60	Subtotal		$	16,223,385
61	Bad Debt Percentage	per GTC 16(f)		2.40%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	389,361
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 160		51,447
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	440,808
67				
68	**Production and Storage Capacity**	per GTC16(f)	$	-
69				
70	**Miscellaneous Overhead**	per GTC 16(f)	$	25,381
71	Sales Volume	Sch. 10B, ln 23/1000		21,908
72	Divided by Total Sales	Sch. 10B, ln 23/1000		105,710
73	Ratio			20.72%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	5,260
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	367,707
78				
79	**Total Cost of Gas**	lns 42 + 77	$	16,679,253
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		21,428,146

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

Ln									
6									Off Peak Period
7	For Month of:		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
8	(a)	(b)	(c)	(d)	(e)	(d)	(e)	(f)	(g)
9	**I. Gas Volumes (Therms)**								
10									
11	**A. Firm Demand Volumes**								
12	Firm Gas Sales	Sch. 10B, ln 23	6,805,137	3,701,258	2,606,423	2,401,822	2,626,827	3,766,964	21,908,432
13	Lost Gas (Unaccounted for)		156,092	120,104	117,646	117,317	132,642	241,670	885,470
14	Company Use		20,216	15,555	15,237	15,194	17,179	31,300	114,681
15	Unbilled Therms		(2,926,855)	(717,132)	316,634	513,046	668,829	2,237,603	92,127
16									
17	**Total Firm Volumes**	Sch. 6, ln 92	4,054,590	3,119,786	3,055,941	3,047,379	3,445,478	6,277,537	23,000,711
18									
19	**B. Supply Volumes (Therms)**								
20	Pipeline Gas:								
21	Dawn Supply	Sch. 6, ln 63	-	-	-	-	-	-	-
22	Niagara Supply	Sch. 6, ln 64	-	-	-	-	-	-	-
23	TGP Supply (Direct)	Sch. 6, ln 65	2,882,508	3,899,955	3,836,489	831,390	831,390	1,313,940	13,595,672
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	-	-	-	-	-
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	1,940,115	-	-	2,995,755	3,390,725	5,722,244	14,048,838
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-
27	LNG Truck	Sch. 6, ln 69	79,674	23,970	24,769	24,769	23,970	24,769	201,922
28	Propane Truck	Sch. 6, ln 70	-	-	-	-	-	-	-
29	PNGTS	Sch. 6, ln 71	38,588	27,250	26,073	26,855	30,783	47,974	197,523
30	Granite Ridge	Sch. 6, ln 72	-	-	-	-	-	-	-
31	Subtotal Pipeline Volumes		4,940,885	3,951,176	3,887,331	3,878,769	4,276,868	7,108,927	28,043,955
32									
33	Storage Gas:								
34	TGP Storage	Sch. 6, ln 77	-	-	-	-	-	-	-
35									
36	Produced Gas:								
37	LNG Vapor	Sch. 6, ln 80	24,769	23,970	24,769	24,769	23,970	24,769	147,017
38	Propane	Sch. 6, ln 81	-	-	-	-	-	-	-
39	Subtotal Produced Gas		24,769	23,970	24,769	24,769	23,970	24,769	147,017
40									
41	Less - Gas Refill:								
42	LNG Truck	Sch. 6, ln 86	(79,674)	(23,970)	(24,769)	(24,769)	(23,970)	(24,769)	(201,922)
43	Propane	Sch. 6, ln 87	-	-	-	-	-	-	-
44	TGP Storage Refill	Sch. 6, ln 88	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(4,988,340)
45	Subtotal Refills		(911,064)	(855,360)	(856,159)	(856,159)	(855,360)	(856,159)	(5,190,262)
46									
47	Total Firm Sendout Volumes		4,054,590	3,119,786	3,055,941	3,047,379	3,445,478	6,277,537	23,000,711
48									

00000002

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5
6

Ln	Description	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Off Peak Period May - Oct
7	For Month of:		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
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 470-0	Sch.5A, ln 16	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 160,191
60	Tenn Gas Pipeline 33371	Sch.5A, ln 17	42,440	42,440	42,440	42,440	42,440	42,440	254,640
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18	15,391	15,391	15,391	15,391	15,391	15,391	92,349
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19	116,711	116,711	116,711	116,711	116,711	116,711	700,264
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20	220,599	220,599	220,599	220,599	220,599	220,599	1,323,595
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21	22,447	22,447	22,447	22,447	22,447	22,447	134,681
65	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22	63,200	63,200	63,200	63,200	63,200	63,200	379,200
66	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 23	60,850	60,850	60,850	60,850	60,850	60,850	365,100
67	Portland Natural Gas Trans Service	Sch.5A, ln 24	27,402	27,402	27,402	27,402	27,402	27,402	164,410
68	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 25	48,097	48,097	48,097	48,097	48,097	48,097	288,584
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		$ 643,836	$ 643,836	$ 643,836	$ 643,836	$ 643,836	$ 643,836	$ 3,863,013
74	Less Capacity Credit		(102,331)	(102,331)	(102,331)	(102,331)	(102,331)	(102,331)	(613,987)
75	Net Pipeline Demand Costs		$ 541,504	$ 541,504	$ 541,504	$ 541,504	$ 541,504	$ 541,504	$ 3,249,026
76									
77	Peaking Supply:								
78	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 34							
79	Granite Ridge Demand	Sch.5A, ln 35							
80	DOMAC Demand FLS-160	Sch.5A, ln 36							
81	Subtotal Peaking Demand								
82	Less Capacity Credit								
83	Net Peaking Supply Demand Costs								
84									
85	Storage:								
86	Dominion - Demand	Sch.5A, ln 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	Dominion - Storage	Sch.5A, ln 47	-	-	-	-	-	-	-
88	Honeoye - Demand	Sch.5A, ln 48	-	-	-	-	-	-	-
89	National Fuel - Demand	Sch.5A, ln 49	-	-	-	-	-	-	-
90	National Fuel - Capacity	Sch.5A, ln 50	-	-	-	-	-	-	-
91	Tenn Gas Pipeline - Demand	Sch.5A, ln 51	-	-	-	-	-	-	-
92	Tenn Gas Pipeline - Capacity	Sch.5A, ln 52	-	-	-	-	-	-	-
93	Subtotal Storage Demand		$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	Less Capacity Credit		-	-	-	-	-	-	-
95	Net Storage Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
96									
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 644,827	$ 644,795	$ 644,827	$ 644,827	$ 644,795	$ 644,827	$ 3,868,899
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(102,489)	(102,484)	(102,489)	(102,489)	(102,484)	(102,489)	(614,923)
99	Net Demand Charges		$ 542,338	$ 542,311	$ 542,338	$ 542,338	$ 542,311	$ 542,338	$ 3,253,976
100									
101									

THIS PAGE HAS BEEN REDACTED

0000003

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

Line									
6									Off Peak Period
7	For Month of:		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
102	**B. Commodity Costs**								
103	Pipeline:								
104	Dawn Supply	Sch. 6, ln 12							
105	Niagara Supply	Sch. 6, ln 13							
106	TGP Supply (Direct)	Sch. 6, ln 14							
107	Dracut Supply 1 - Baseload	Sch. 6, ln 15							
108	Dracut Supply 2 - Swing	Sch. 6, ln 16							
109	City Gate Delivered Supply	Sch. 6, ln 17							
110	LNG Truck	Sch. 6, ln 18							
111	Propane Truck	Sch. 6, ln 19							
112	PNGTS	Sch. 6, ln 20							
113	Granite Ridge	Sch. 6, ln 21							
114	Subtotal Pipeline Commodity Costs		$ 2,403,401	$ 1,887,353	$ 1,893,297	$ 2,040,425	$ 2,259,585	$ 3,828,631	$ 14,312,692
115									
116	Storage:								
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118									
119	Produced Gas Costs:								
120	LNG Vapor	Sch. 6, ln 50							
121	Propane	Sch. 6, ln 51							
122	Subtotal Produced Gas Costs		$ 13,216	$ 12,651	$ 12,972	$ 12,906	$ 12,446	$ 12,854	$ 77,045
123									
124	Less Storage Refills:								
125	LNG Truck	Sch. 6, ln 37							
126	Propane	Sch. 6, ln 38							
127	TGP Storage Refill	Sch. 6, ln 39							
128	Storage Refill (Trans.)	Sch. 6, ln 40							
129	Subtotal Storage Refill		$ (479,579)	$ (459,497)	$ (467,562)	$ (473,111)	$ (476,007)	$ (485,378)	$ (2,841,135)
130									
131	Total Supply Commodity Costs		$ 1,937,037	$ 1,440,507	$ 1,438,707	$ 1,580,219	$ 1,796,024	$ 3,356,107	$ 11,548,601
132									
133	**C. Supply Volumetric Transportation Costs:**								
134	Dawn Supply	Sch. 6, ln 26							
135	Niagara Supply	Sch. 6, ln 27							
136	TGP Supply (Direct)	Sch. 6, ln 28							
137	Dracut Supply 1 - Baseload	Sch. 6, ln 29							
138	Dracut Supply 2 - Swing	Sch. 6, ln 30							
139	Subtotal Pipeline Volumetric Trans. Costs		$ 161,655	$ 192,609	$ 191,703	$ 74,520	$ 79,133	$ 130,402	$ 830,022
140									
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142									
143	Total Supply Volumetric Trans. Costs		$ 161,655	$ 192,609	$ 191,703	$ 74,520	$ 79,133	$ 130,402	$ 830,022
144									
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ 2,098,692	$ 1,633,116	$ 1,630,410	$ 1,654,739	$ 1,875,158	$ 3,486,509	$ 12,378,623
146									
147									

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Line	Description	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Off Peak Period May - Oct
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Off Peak 2010 Summer Cost of Gas Filing**								
4	**Summary of Supply and Demand Forecast**								
5									
6									Off Peak Period
7	For Month of:		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
148	**D. Supply and Demand Costs by Source**								
149									
150	Purchased Gas Demand Costs								
151	Pipeline Gas Demand Costs	lns 54 + 73	$ 644,827	$ 644,795	$ 644,827	$ 644,827	$ 644,795	$ 644,827	$ 3,868,899
152	Peaking Gas Demand Costs	ln 81	-	-	-	-	-	-	-
153	Subtotal Purchased Gas Demand Costs		$ 644,827	$ 644,795	$ 644,827	$ 644,827	$ 644,795	$ 644,827	$ 3,868,899
154	Less Capacity Credit	lns 55 + 74 + 82	(102,489)	(102,484)	(102,489)	(102,489)	(102,484)	(102,489)	(614,923)
155	Net Purchased Gas Demand Costs		$ 542,338	$ 542,311	$ 542,338	$ 542,338	$ 542,311	$ 542,338	$ 3,253,976
156									
157	Storage Gas Demand Costs								
158	Storage Demand	ln 93	$ -	$ -	$ -	$ -	$ -	$ -	$ -
159	Less Capacity Credit	ln 94	-	-	-	-	-	-	-
160	Net Storage Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
161									
162	**Total Demand Costs**	lns 155 + 160	$ 542,338	$ 542,311	$ 542,338	$ 542,338	$ 542,311	$ 542,338	$ 3,253,976
163									
164	Purchased Gas Supply								
165	Commodity Costs	ln 114	$ 2,403,401	$ 1,887,353	$ 1,893,297	$ 2,040,425	$ 2,259,585	$ 3,828,631	$ 14,312,692
166	Less Storage Inj.(TGP Storage)	ln 127							
167	Less Storage Transportation	ln 128							
168	Less LNG Truck	ln 125							
169	Less Propane Truck	ln 126							
170	Plus Transportation Costs	ln 139	161,655	192,609	191,703	74,520	79,133	130,402	830,022
171	Subtotal Purchased Gas Supply		$ 2,085,476	$ 1,620,466	$ 1,617,438	$ 1,641,833	$ 1,862,711	$ 3,473,655	$ 12,301,578
172									
173	Storage Commodity Costs								
174	Commodity Costs	ln 117	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	Transportation Costs	ln 141	-	-	-	-	-	-	-
176	Subtotal Storage Commodity Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
177									
178	Produced Gas Commodity Costs	ln 122	$ 13,216	$ 12,651	$ 12,972	$ 12,906	$ 12,446	$ 12,854	$ 77,045
179									
180	**SubTotal Commodity Costs**	lns 171 + 176 + 178	$ 2,098,692	$ 1,633,116	$ 1,630,410	$ 1,654,739	$ 1,875,158	$ 3,486,509	$ 12,378,623
181									
182	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ 446,305	$ -	$ -	$ -	$ -	$ 184,089	$ 630,394
183									
184	**Total Commodity Costs**	lns 180 + 182	$ 2,544,996	$ 1,633,116	$ 1,630,410	$ 1,654,739	$ 1,875,158	$ 3,670,598	$ 13,009,017
185									
186	**Total Demand Costs**	ln 99	$ 542,338	$ 542,311	$ 542,338	$ 542,338	$ 542,311	$ 542,338	$ 3,253,976
187	**Total Supply Costs**	ln 184	2,544,996	1,633,116	1,630,410	1,654,739	1,875,158	3,670,598	13,009,017
188									
189	**Total Direct Gas Costs**	lns 186 + 187	$ 3,087,335	$ 2,175,428	$ 2,172,748	$ 2,197,077	$ 2,417,469	$ 4,212,936	$ 16,262,993
190									
191									

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Contracts Ranked on a per Unit Cost Basis**
5

Line	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Off Peak Cost per Unit Dth
	Demand Costs					
10		3000			102 00	
11					1 5 0 3 1	
12		1 235			0 00	
13					3 1	
14					21 44	
15					15 000	
1		3000			34	
1		1 235			0	
1		420			20 000	
1		235			0	
20		2302 5			3 122	
21		11234 5			1 5	
22		5 4			3 11	
23		32 4			15 2 5	
24		11234 4			0 2	
25					1 3 2	
2		4 0 01			4 04	
2		333 1			4 000	
2					4 04	
2					30 000	
30		5 1			14 5 1	
31		5 0			035	
32		1 001			1 000	
33						
34	**Supply Costs - Commodity**					
35					20 1 2	
3					1 35 5	
3						
3						
3						
40					14 02	
41						
42					1 52	
43	2				1 404 4	
44						
45						
4						
4	**Supply Costs - Volumetric Transportation**					
4	2				1 404 4	
4	1					
50						
51						
52					1 35 5	
53						
54		THIS PAGE HAS BEEN REDACTED				

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

Line																	
5			Prior Period Balance														
6			Plus Nov Collections	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Off Peak Period
7		Days in Month	October 31, 2009	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
9	**Account 175.40 COG (Over)/Under Balance - Interest Calculation**																
10																	
11	**Beginning Balance**	Account 175.40 1/	$ 520,566	$ 38,753	$ 39,500	$ 39,609	$ 39,718	$ 39,817	$ 39,927	$ 40,034	$ 177,172	$ 82,903	$ 32,240	$ 12,040	$ (77,697)	$ (434,065)	$ 520,566
12	Forecast Direct Gas Costs			-	-	-	-	-	-	3,087,335	2,175,428	2,172,748	2,197,077	2,417,469	4,212,936	-	16,262,993
13	Production & Storage & Misc Overhead			-	-	-	-	-	-	877	877	877	877	877	877		5,260
14	Projected Revenues w/o Int.	ln 51 * 61		-	-	-	-	-	-	(2,071,484)	(2,816,658)	(1,983,488)	(1,827,787)	(1,999,015)	(2,866,660)	(2,741,728)	(16,306,819)
15	Projected Unbilled Revenue									(879,889)	(334,152)	(575,111)	(965,539)	(1,474,518)	(3,177,334)	-	(7,406,542)
16	Reverse Prior Month Unbilled										879,889	334,152	575,111	965,539	1,474,518	3,177,334	7,406,542
17	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Gas Cost Billed	Account 175.40 2/	(481,813)	-	-	-	-	-	-	-	-	-	-	-	-	-	(481,813)
19	Monthly (Over)/Under Recovery		$ 38,753	$ 38,753	$ 39,500	$ 39,609	$ 39,718	$ 39,817	$ 39,927	$ 176,873	$ 82,556	$ 32,081	$ 11,979	$ (77,609)	$ (433,360)	$ 1,541	$ 187
20	Average Monthly Balance	(ln 11 + 19)/ 2	$ -	$ 279,659	$ 39,500	$ 39,609	$ 39,718	$ 39,817	$ 39,927	$ 108,453	$ 129,864	$ 57,492	$ 22,109	$ (32,785)	$ (255,528)	$ (216,262)	
21																	
22	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%		
23																	
24	Interest Applied	ln 20 * ln 22 / 365 * Days of M		$ 747	$ 109	$ 109	$ 99	$ 110	107	$ 299	$ 347	$ 159	$ 61	$ (88)	$ (705)	$ -	$ 1,354
25																	
26	**(Over)/Under Balance**	ln 19 + ln 24	$ 38,753	$ 39,500	$ 39,609	$ 39,718	$ 39,817	$ 39,927	40,034	$ 177,172	$ 82,903	$ 32,240	$ 12,040	$ (77,697)	$ (434,065)	$ 1,541	1,541
27																	
28																	
29	**Calculation of COG with Interest**																
30																	
31	**Beginning Balance**	ln 11	$ 520,566	$ 38,753	$ 39,500	$ 39,609	$ 39,718	$ 39,817	39,927	$ 40,034	$ 175,230	$ 961,106	$ 364,554	$ 585,262	$ 886,613	$ 1,039,915	$ 520,566
32	Forecast Direct Gas Costs	ln 12		-	-	-	-	-	-	3,087,335	2,175,428	2,172,748	2,197,077	2,417,469	4,212,936	-	16,262,993
33	Prod Storage & Misc Overhead	ln 13		-	-	-	-	-	-	877	877	877	877	877	877	-	5,260
34	Projected Revenues with int.	ln 51 * 63		-	-	-	-	-	-	(2,072,845)	(2,818,508)	(1,984,791)	(1,828,988)	(2,000,329)	(2,868,543)	(2,743,529)	(16,317,533)
35	Projected Unbilled Revenue									(880,467)	546,096	(241,117)	(390,684)	(509,314)	(1,703,935)		(3,179,422)
36	Reverse Prior Month Unbilled										880,467	(546,096)	241,117	390,684	509,314	1,703,935	3,179,422
37	Add Net Adjustments	ln 17		-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Gas Cost Billed	ln 18	(481,813)	-	-	-	-	-	-	-	-	-	-	-	-	-	(481,813)
39	Gas Cost Unbilled									-	-	-	-	-	-		-
40	Reverse Prior Month Unbilled										-	-	-	-	-	-	-
41	Add Interest	ln 24		-	-	-	-	-	-	299	347	159	61	(88)	(705)	-	73
42	**(Over)/Under Balance**		$ 38,753	$ 38,753	$ 39,500	$ 39,609	$ 39,718	$ 39,817	39,927	$ 175,233	$ 959,937	$ 362,885	$ 584,014	$ 884,562	$ 1,036,556	$ 321	$ (10,454)
43																	
44	Average Monthly Balance			$ 279,659	$ 39,500	$ 39,609	$ 39,718	$ 39,817	39,927	$ 107,633	$ 567,584	$ 661,996	$ 474,284	$ 734,912	$ 961,584		
45																	
46	Interest Applied	ln 22 * ln 44 / 365 * Days of Month		747	109	109	99	110	107	297	1,516	1,827	1,309	1,963	2,654	-	$ 10,848
47																	
48	**(Over)/Under Balance**	ln 41 +ln 42 + ln 46	$ 38,753	$ 39,500	$ 39,609	$ 39,718	$ 39,817	$ 39,927	40,034	$ 175,230	$ 961,106	$ 364,554	$ 585,262	$ 886,613	$ 1,039,915	$ 321	321
49																	
50																	
51	Forecast Sendout Therms	Sch 1								4,054,590	3,119,786	3,055,941	3,047,379	3,445,478	6,277,537		23,000,711
52	Less 'Forecast Billing Therm Sales	Sch. 10B, ln 23 May - Oct								2,722,055	3,701,258	2,606,423	2,401,822	2,626,827	3,766,964	3,602,796	21,428,146
53	Less Forecast Unaccounted For	Sch 1								156,092	120,104	117,646	117,317	132,642	241,670		885,470
54	Less Forecast Company Use	Sch 1								20,216	15,555	15,237	15,194	17,179	31,300	-	114,681
55	Unbilled Volumes									1,156,228	-717,132	316,634	513,046	668,829	2,237,603	-3,602,796	572,413
56																	
57	Beg Balance									-	1,156,228	439,096	755,730	1,268,776	1,937,606	4,175,209	
58	Incremental									1,156,228	(717,132)	316,634	513,046	668,829	2,237,603	(3,602,796)	
59	Ending Balance									1,156,228	439,096	755,730	1,268,776	1,937,606	4,175,209	572,413	
60																	
61	COG w/o Interest	Sch. 3, pg. 4, ln 208 col. (c)								$0.7610	$0.7610	$0.7610	$0.7610	$0.7610	$0.7610	$0.7610	
62																	
63	COG With Interest	Sch. 3, pg. 4, ln 208 col. (d)								$0.7615	$0.7615	$0.7615	$0.7615	$0.7615	$0.7615	$0.7615	

64
65 1/ Beginning Balance for Acct 175.40, per Schedule 1, page 2, line 23, October 2009 column, as filed in the DG 09-050 Summer Cost of Gas Reconciliation, filed on 1/28/2010.
66 2/ Gas Cost Billed Acct 175.40, per Schedule 1, page 2, line 11, November 2009 column, as filed in the DG 09-050 Summer Cost of Gas Reconciliation, filed on 1/28/2010.
67

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

Ln																	
68			Prior Period Balance	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Off Peak Period
69		Days in Month	Plus Nov Collections	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
70			October 31, 2009														
71	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
72																	
73	**Account 142.40 Working Capital (Over)/Under Balance - Interest Calculation**																
74																	
75	**Beginning Balance**	Account 142.40 1/	$ (91,430)	$ (93,103)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (94,611)	$ (77,690)	$ (64,857)	$ (52,223)	$ (39,563)	$ (25,254)	$ 758	$ (91,430)
76																	
77	Days Lag									10.18	10.18	10.18	10.18	10.18	10.18	10.18	
78	Prime Rate									3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
79	Forecast Working Capital	ln 32 * ln 77 / 365 * ln 78		-	-	-	-	-	-	2,798	1,972	1,969	1,992	2,191	3,819	-	14,741
80																	
81	Projected Revenues w/o Int.	ln 120 * ln 123		-	-	-	-	-	-	10,072	13,695	9,644	8,887	9,719	13,938	13,330	79,284
82	Projected Unbilled Revenue									4,278	1,625	2,796	4,694	7,169	15,448		36,011
83	Reverse Prior Month Unbilled										(4,278)	(1,625)	(2,796)	(4,694)	(7,169)	(15,448)	(36,011)
84																	
85	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
86																	
87	Working Capital Billed	Account 142.40 2/	(1,673)														(1,673)
88																	
89	Monthly (Over)/Under Recovery		$ (93,103)	$ (93,103)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (77,453)	$ (64,667)	$ (52,062)	$ (39,436)	$ (25,167)	$ 792	$ (1,350)	$ 923
90																	
91	Average Monthly Balance	(ln 75 + 89)/ 2		$ (92,266)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (86,032)	$ (71,178)	$ (58,459)	$ (45,830)	$ (32,365)	$ (12,231)		
92																	
93	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%		
94																	
95	Interest Applied	ln 91 * ln 93 / 365 * Days of Month		$ (246)	$ (258)	$ (258)	$ (234)	$ (260)	$ (252)	$ (237)	$ (190)	$ (161)	$ (127)	$ (86)	$ (34)		$ (2,344)
96																	
97	**(Over)/Under Balance**	ln 89 + ln 95	$ (93,103)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (94,611)	$ (77,690)	$ (64,857)	$ (52,223)	$ (39,563)	$ (25,254)	$ 758	$ (1,350)	(1,421)
98																	
99																	
100	**Calculation of Working Capital with Interest**																
101																	
102	**Beginning Balance**		$ (91,430)	$ (93,103)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (94,611)	$ (77,312)	$ (64,190)	$ (51,272)	$ (38,328)	$ (23,696)	$ 2,912	$ (91,430)
103	Forecast Working Capital	ln 79		-	-	-	-	-	-	2,798	1,972	1,969	1,992	2,191	3,819	-	14,741
104	Projected Rev. with interest	ln 120 * ln 125		-	-	-	-	-	-	10,344	14,065	9,904	9,127	9,982	14,314	13,691	81,427
105	Projected Unbilled Revenue									4,394	1,669	2,872	4,821	7,363	15,866		36,984
106	Reverse Prior Month Unbilled										(4,394)	(1,669)	(2,872)	(4,821)	(7,363)	(15,866)	(36,984)
107	Add Net Adjustments	ln 85		-	-	-	-	-	-	-	-	-	-	-	-	-	-
108	Working Capital Billed	ln 87	(1,673)														(1,673)
109	WC Unbilled									-	-	-	-	-	-	-	-
110	Reverse WC Unbilled										-	-	-	-	-	-	-
111	Add Interest	ln 95		-	-	-	-	-	-	(237)	(190)	(161)	(127)	(86)	(34)		(836)
112	Monthly (Over)/Under Recovery		$ (93,103)	$ (93,103)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (77,312)	$ (64,191)	$ (51,274)	$ (38,330)	$ (23,699)	$ 2,907	$ 737	$ 2,230
113																	
114	Average Monthly Balance			$ (92,266)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (85,962)	$ (70,751)	$ (57,732)	$ (44,801)	$ (31,013)	$ (10,394)		
115																	
116	Interest Applied	ln 93 * ln 114 / 365 * Days of Month		(246)	(258)	(258)	(234)	(260)	(252)	(237)	(189)	(159)	(124)	(83)	(29)	-	$ (2,329)
117																	
118	**(Over)/Under Balance**	-ln 111 +ln 112 + ln 116	$ (93,103)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (94,611)	$ (77,312)	$ (64,190)	$ (51,272)	$ (38,328)	$ (23,696)	$ 2,912	$ 737	$ 737
119																	
120	Forecast Therm Sales	ln 51								2,722,055	3,701,258	2,606,423	2,401,822	2,626,827	3,766,964	3,602,796	21,428,146
121	Unbilled Therm	ln 53								1,156,228	439,096	755,730	1,268,776	1,937,606	4,175,209	572,413	
122																	
123	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 225 col. (c)								-$0.0037	-$0.0037	-$0.0037	-$0.0037	-$0.0037	-$0.0037	-$0.0037	
124																	
125	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 225 col. (d)								-$0.0038	-$0.0038	-$0.0038	-$0.0038	-$0.0038	-$0.0038	-$0.0038	

126 1/ Beginning Balance for Acct 142.4, per Schedule 5, page 2, line 16, October 2009 column, as filed in the DG 09-050 Summer Cost of Gas Reconciliation, filed on 1/28/2010.
127 2/ Gas Cost Billed Acct 145.40, per Schedule 5, page 2, line 8, November 2009 column, as filed in the DG 09-050 Summer Cost of Gas Reconciliation, filed on 1/28/2010.
128

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

Line			Prior Period Balance Plus Nov Collections October 31, 2009	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Off Peak Period Total
131		Days in Month		30	31	31	28	31	30	31	30	31	31	30	31	30	
132	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
133																	
134	**Account 175.54 Bad Debt (Over)/Under Balance - Interest Calculation**																
135																	
136	Forecast Direct Gas Costs	ln 32		$ -	$ -	$ -	$ -	$ -	$ -	$ 3,087,335	$ 2,175,428	$ 2,172,748	$ 2,197,077	$ 2,417,469	$ 4,212,936	$ -	16,262,993
137	Forecast Working Capital	ln 103 + (May includes prior period)		-	-	-	-	-	-	(90,304)	1,972	1,969	1,992	2,191	3,819		(78,361)
138	Prior Period Balance	ln 19 / 6								6,459	6,459	6,459	6,459	6,459	6,459		38,753
139	Total Forecast Direct Gas Costs & Working Capital			-	-	-	-	-	-	3,003,490	2,183,859	2,181,176	2,205,527	2,426,119	4,223,214	-	16,184,632
140																	
141	**Beginning Balance**	Account 175.54 1/	$ 57,023	$ 51,447	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 52,289	$ 44,614	$ 35,553	$ 27,774	$ 20,727	$ 11,106	$ (11,231)	$ 57,023
142																	
143	Forecast Bad Debt	ln 139 * .97%		-	-	-	-	-	-	72,084	52,413	52,348	52,933	58,227	101,357		389,361
144																	
145	Projected Revenues w/o int	ln 181 * ln 184		-	-	-	-	-	-	(56,074)	(76,246)	(53,692)	(49,478)	(54,113)	(77,599)	(74,218)	(441,420)
146	Projected Unbilled Revenue									(23,818)	(9,045)	(15,568)	(26,137)	(39,915)	(86,009)		(200,492)
147	Reverse Prior Month Unbilled										23,818	9,045	15,568	26,137	39,915	86,009	200,492
148																	-
149	Bad Debt Billed	Account 175.54 2/	(5,576)		-	-	-	-	-								(5,576)
150	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
151																	
152	Monthly (Over)/Under Recovery		$ 51,447	$ 51,447	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 44,480	$ 35,553	$ 27,687	$ 20,660	$ 11,064	$ (11,231)	$ 561	$ (612)
153																	
154	Average Monthly Balance	(ln 141 + 152)/ 2		$ 54,235	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 48,385	$ 40,084	$ 31,620	$ 24,217	$ 15,895	$ (62)	$ (5,335)	
155																	
156	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%		
157																	
158	Interest Applied	ln 154 * ln 156 / 365 * Days of Mo.		$ 145	$ 142	$ 143	$ 129	$ 144	$ 139	$ 134	$ 107	$ 87	$ 67	$ 42	$ (0)		$ 1,279
159																	
160	**(Over)/Under Balance**	ln 152 + ln 158	$ 51,447	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 52,289	$ 44,614	$ 35,661	$ 27,774	$ 20,727	$ 11,106	$ (11,231)	$ (5,335)	668
161																	
162																	
163	**Calculation of Bad Debt with Interest**																
164																	
165	**Beginning Balance**		$ 57,023	$ 51,447	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 52,289	$ 44,614	$ 35,661	$ 27,882	$ 20,835	$ 11,215	$ (11,122)	$ 57,023
166	Forecast Bad Debt	ln 143		-	-	-	-	-	-	72,084	52,413	52,348	52,933	58,227	101,357	-	389,361
167	Projected Revenues with int.	ln 181 * 186		-	-	-	-	-	-	(56,074)	(76,246)	(53,692)	(49,478)	(54,113)	(77,599)	(74,218)	(441,420)
168	Projected Unbilled Revenue									(23,818)	(9,045)	(15,568)	(26,137)	(39,915)	(86,009)		(200,492)
169	Reverse Prior Month Unbilled										23,818	9,045	15,568	26,137	39,915	86,009	200,492
170	Bad Debt Billed	ln 149	(5,576)		-	-	-	-	-								(5,576)
171	Add Interest	ln 158		-	-	-	-	-	-	134	107	87	67	42	(0)		437
172	Add Net Adjustments	ln 150		-	-	-	-	-	-	-	-	-	-	-	-	-	-
173	Monthly (Over)/Under Recovery		$ 51,447	$ 51,447	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 44,614	$ 35,661	$ 27,881	$ 20,835	$ 11,214	$ (11,123)	$ 669	$ (175)
174																	
175	Average Monthly Balance	(ln 165 + 173)/ 2		$ 54,235	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 48,452	$ 40,137	$ 31,771	$ 24,358	$ 16,025	$ 46	$ (5,226)	
176																	
177	Interest Applied	ln 156 * ln 175 / 365 * Days of Month		145	142	143	129	144	139	134	107	88	67	43	0	-	$ 1,281
178																	
179	**(Over)/Under Balance**	-ln 171 +ln 173 + ln 177	$ 51,447	$ 51,592	$ 51,734	$ 51,877	$ 52,006	$ 52,150	$ 52,289	$ 44,614	$ 35,661	$ 27,882	$ 20,835	$ 11,215	$ (11,122)	$ 669	$ 669
180																	
181	Forecast Therm Sales	ln 51								2,722,055	3,701,258	2,606,423	2,401,822	2,626,827	3,766,964	3,602,796	21,428,146
182	Unbilled Therm	ln 53								1,156,228	439,096	755,730	1,268,776	1,937,606	4,175,209		
183																	
184	COG Rate Without Interest	Sch. 3, pg. 4, ln 242 col. (c)								$0.0206	$0.0206	$0.0206	$0.0206	$0.0206	$0.0206	$0.0206	
185																	
186	COG With Interest	Sch. 3, pg. 4, ln 242 col. (d)								$0.0206	$0.0206	$0.0206	$0.0206	$0.0206	$0.0206	$0.0206	

187 1/ Beginning Balance for Acct 175.54, per Schedule 1, page 4, line 18, October 2009 column, as filed in the DG 09-050 Summer Cost of Gas Reconciliation, filed on 1/28/2010.
188 2/ Gas Cost Billed Acct 175.54, per Schedule 1, page 4, line 8, November 2009 column, as filed in the DG 09-050 Summer Cost of Gas Reconciliation, filed on 1/28/2010.
189

Line				Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Off Peak Period Total
190	**Total Interest**	lns 46 + 116 + 177		$ 645	$ (6)	$ (6)	$ (6)	$ (6)	$ (6)	$ 194	$ 1,434	$ 1,756	$ 1,253	$ 1,923	$ 2,626	$ -	$ 9,800
191																	

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

			COG Rate Without Interest	COG Rate With Interest
192	**Calculation of COG**			
193	(a)	(b)	(c)	(d)
194	(Over)Under Recovery Balance	ln 11, col. (d)	$ 38,753	$ 38,753
195				
196	Unadjusted Forecast of Gas Costs	ln 12, col. (q)	16,262,993	16,262,993
197				
198	Production & Storage and Misc Ov	ln 13, col. (q)	5,260	5,260.2
199				
200	Adjustments	ln 17, col. (q)	-	-
201				
202	Interest May - Oct	ln 46, col. (q)	-	$ 10,848
203				
204	Total Gas To Be Recovered		$ 16,307,006	$ 16,317,854
205				
206	Forecast Gas Sales (May - Oct)	ln 52, col. (q)	21,428,146	21,428,146
207				
208	Preliminary COG Rate	ln 204 / 206	$0.7610	$0.7615
209				
210				
			Working Capital Rate without interest	Working Capital Rate with Interest
211	**Calculation of Working Capital Rate**			
212	(a)	(b)	(c)	(d)
213	(Over)Under Recovery Balance	ln 75, col. (q)	$ (93,103)	$ (93,103)
214				
215	Unadjusted Working Capital Forecast	ln 79, col. (q)	14,741	14,741
216				
217	Adjustments without interest	ln 85, col. (q)	-	-
218				
219	Interest May - Oct	ln 116, col. (q)	-	$ (2,329)
220				
221	Total Gas To Be Recovered		$ (78,361)	$ (80,690)
222				
223	Forecast Gas Sales	ln 51, col. (q)	21,428,146	21,428,146
224				
225	Preliminary Working Capital COG F	ln 221 / 223	-$0.0037	-$0.0038
226				
227				
			Bad Debt Rate without Interest	Bad Debt Rate with interest
228	**Calculation of Bad Debt Rate**			
229	(a)	(b)	(c)	
230	(Over)Under Recovery Balance	ln 141, col. (q)	$ 51,447	$ 51,447
231				
232	Unadjusted Bad Debt Forecast	ln 143, col. (q)	389,361	389,361
233				
234	Adjustments without interest	ln 150, col. (q)	-	-
235				
236	Interest May - Oct	ln 177, col. (q)	-	$ 1,281
237				
238	Total Gas To Be Recovered		$ 440,808	$ 442,089
239				
240	Forecast Gas Sales (May - Oct)	ln 51, col. (q)	21,428,146	21,428,146
241				
242	Preliminary Bad Debt COG Rate	ln 238 / 240	$0.0206	$0.0206

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer 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	Interruptible Sales Margin	Off System Sales Margin	Capacity Release Margin	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	Nov-08	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
10	Dec-08	-	-	-	-	-	-		-	-	-	-
11	Jan-09	-	-	-	-	-	-		-	-	-	-
12	Feb-09	-		-	-	-	-		-	-	-	-
13	Mar-09	-	-	-	-	-	-		-	-	-	-
14	Apr-09	-	-	-	-	-	-		-	-	-	-
15	May-09	-	-	-	-	-	-		-	-	-	-
16	Jun-09	-	-	-	-	-	-		-	-	-	-
17	Jul-09	-	-	-	-	-	-		-	-	-	-
18	Aug-09	-	-	-	-	-	-		-	-	-	-
19	Sep-09	-	-	-	-	-	-		-	-	-	-
20	Oct-09	-	-	-	-	-	-		-	-	-	-
21												
22	Total Off Peak Period	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -

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

Line	(a)	Peak (b)	Reference (c)	May-10 (d)	Jun-10 (e)	Jul-10 (f)	Aug-10 (g)	Sep-10 (h)	Oct-10 (i)	Off Peak May - Oct Total (j)	Peak May - Oct Total (k)
5											
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	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 26,698	$ 160,191	0
17	Tenn Gas Pipeline 33371		Sch 5B, ln 13 * Sch 5C ln 16 x days	42,440	42,440	42,440	42,440	42,440	42,440	254,640	0
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 18 x days	15,391	15,391	15,391	15,391	15,391	15,391	92,349	0
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 20 x days	116,711	116,711	116,711	116,711	116,711	116,711	700,264	0
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 22 x days	220,599	220,599	220,599	220,599	220,599	220,599	1,323,595	0
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 24 x days	22,447	22,447	22,447	22,447	22,447	22,447	134,681	0
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 26 x days	63,200	63,200	63,200	63,200	63,200	63,200	379,200	0
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 28 x days	60,850	60,850	60,850	60,850	60,850	60,850	365,100	
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 30 x days	27,402	27,402	27,402	27,402	27,402	27,402	164,410	0
25	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 21 * Sch 5C ln 46 x days	48,097	48,097	48,097	48,097	48,097	48,097	288,584	0
26	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 22 * Sch 5C ln 32 x days	89,911	89,911	89,911	89,911	89,911	89,911	-	539,465
27	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 23 * Sch 5C ln 34 x days	41,713	41,713	41,713	41,713	41,713	41,713	-	250,278
28	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 24 * Sch 5C ln 36 x days	9,648	9,648	9,648	9,648	9,648	9,648	-	57,888
29	National Fuel FST 2358	peak	Sch 5B, ln 25 * Sch 5C ln 38 x days	20,497	20,497	20,497	20,497	20,497	20,497	-	122,980
30											
31	Subtotal Pipeline Demand Charges			$ 805,604	$ 805,604	$ 805,604	$ 805,604	$ 805,604	$ 805,604	$ 3,863,013	$ 970,611
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										
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 1,130,846	$ 1,130,814	$ 1,130,846	$ 1,130,846	$ 1,130,814	$ 1,130,846	$ 3,868,899	$ 2,916,111
40											
41	Less Transportation Capacity Credit			$ (179,737)	$ (179,732)	$ (179,737)	$ (179,737)	$ (179,732)	$ (179,737)	$ (614,923)	$ (463,487)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 951,109	$ 951,082	$ 951,109	$ 951,109	$ 951,082	$ 951,109	$ 3,253,976	$ 2,452,624
44											

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Demand Costs**
5

Line	(a)	Peak (b)	Reference (c)	May-10 (d)	Jun-10 (e)	Jul-10 (f)	Aug-10 (g)	Sep-10 (h)	Oct-10 (i)	Off Peak May - Oct Total (j)	Peak May - Oct Total (k)
45	**Storage**										
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 53 x days	$ 1,753	$ 1,753	$ 1,753	$ 1,753	$ 1,753	$ 1,753	$ -	$ 10,520
47	Dominion - Storage	peak	Sch 5B, ln 34 * Sch 5C ln 54 x days	1,489	1,489	1,489	1,489	1,489	1,489	-	8,935
48	Honeoye - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 57 x days	8,744	8,744	8,744	8,744	8,744	8,744	-	52,466
49	National Fuel - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 59 x days	13,145	13,145	13,145	13,145	13,145	13,145	-	78,869
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 60 x days	28,979	28,979	28,979	28,979	28,979	28,979	-	173,871
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 63 x days	25,121	25,121	25,121	25,121	25,121	25,121	-	150,724
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 64 x days	28,867	28,867	28,867	28,867	28,867	28,867	-	173,203
53											
54	**Subtotal Storage Demand Costs**			$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ -	$ 648,589
55											
56	Less Transportation Capacity Credit			$ (17,181)	$ (17,181)	$ (17,181)	$ (17,181)	$ (17,181)	$ (17,181)	$ -	$ (103,087)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 90,917	$ 90,917	$ 90,917	$ 90,917	$ 90,917	$ 90,917	$ -	$ 545,502
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 1,238,944	$ 1,238,912	$ 1,238,944	$ 1,238,944	$ 1,238,912	$ 1,238,944	$ 3,868,899	$ 3,564,700
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (196,918)	$ (196,913)	$ (196,918)	$ (196,918)	$ (196,913)	$ (196,918)	$ (614,923)	$ (566,574)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,042,026	$ 1,041,999	$ 1,042,026	$ 1,042,026	$ 1,041,999	$ 1,042,026	$ 3,253,976	$ 2,998,126
65											
66											
67	Monthly Off Peak Demand			$ 644,827	$ 644,795	$ 644,827	$ 644,827	$ 644,795	$ 644,827	$ 3,868,899	$ -
68	Monthly Off Peak Transportation Cap Credit			(102,489)	(102,484)	(102,489)	(102,489)	(102,484)	(102,489)	(614,923)	-
69	**Total Off Peak Demand**			$ 542,338	$ 542,311	$ 542,338	$ 542,338	$ 542,311	$ 542,338	$ 3,253,976	$ -
70											
71	Monthly Peak Demand			$ 594,117	$ 594,117	$ 594,117	$ 594,117	$ 594,117	$ 594,117	$ -	$ 3,564,700
72	Monthly Peak Transportation Cap Credit			(94,429)	(94,429)	(94,429)	(94,429)	(94,429)	(94,429)	-	(566,574)
73	**Total Peak Demand**			$ 499,688	$ 499,688	$ 499,688	$ 499,688	$ 499,688	$ 499,688	$ -	$ 2,998,126

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
<u>Demand Volumes</u>

		Peak	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-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
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
Off Peak 2010 Summer Cost of Gas Filing
Demand Rates

				May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
Tariff Rates				31	30	31	31	30	31	184
				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	$0.2128	$0.2199	$0.2128	$0.2128	$0.2199	$0.2128	$0.2152
Tenn Gas Pipeline	33371 Segment 3	$5.0700	43nd Rev Sheet No. 26B	$0.1635	$0.1690	$0.1635	$0.1635	$0.1690	$0.1635	$0.1654
Tenn Gas Pipeline	33371 Segment 4	$5.5400	43nd Rev Sheet No. 26B	$0.1787	$0.1847	$0.1787	$0.1787	$0.1847	$0.1787	$0.1807
		$10.6100		$0.3423	$0.3537	$0.3423	$0.3423	$0.3537	$0.3423	$0.3461
Tenn Gas Pipeline	2302 Z5-Z6	$4.9300	26th Rev Sheet No. 23	$0.1590	$0.1643	$0.1590	$0.1590	$0.1643	$0.1590	$0.1608
Tenn Gas Pipeline	8587 Z0-Z6	$16.5900	26th Rev Sheet No. 23	$0.5352	$0.5530	$0.5352	$0.5352	$0.5530	$0.5352	$0.5411
Tenn Gas Pipeline	8587 Z1-Z6	$15.1500	26th Rev Sheet No. 23	$0.4887	$0.5050	$0.4887	$0.4887	$0.5050	$0.4887	$0.4941
Tenn Gas Pipeline	8587 Z4-Z6	$5.8900	26th Rev Sheet No. 23	$0.1900	$0.1963	$0.1900	$0.1900	$0.1963	$0.1900	$0.1921
TGP Dracut	42076 FTA Z6-Z6	$3.1600	26th Rev Sheet No. 23	$0.1019	$0.1053	$0.1019	$0.1019	$0.1053	$0.1019	$0.1031
TGP Concord Lateral	Z6-Z6	$12.1700	per contract	$0.3926	$0.4057	$0.3926	$0.3926	$0.4057	$0.3926	$0.3969
Portland Natural Gas	FT-1999-001	$27.4017	7th Rev Sheet No. 100	$0.8839	$0.9134	$0.8839	$0.8839	$0.9134	$0.8839	$0.8937
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$5.8900	26th Rev Sheet No. 23	$0.1900	$0.1963	$0.1900	$0.1900	$0.1963	$0.1900	$0.1921
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$5.8900	26th Rev Sheet No. 23	$0.1900	$0.1963	$0.1900	$0.1900	$0.1963	$0.1900	$0.1921
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$4.9300	26th Rev Sheet No. 23	$0.1590	$0.1643	$0.1590	$0.1590	$0.1643	$0.1590	$0.1608
National Fuel	FST 2358	$3.3612	131st Rev Sheet No. 9	$0.1084	$0.1120	$0.1084	$0.1084	$0.1120	$0.1084	$0.1096
ANE TransCanada PipeLines Limited		$10.8267	Union Dawn to Iroquois							
Delivery Pressure Demand Charge		0.7857	Union Dawn to Iroquois							
Sub Total Demand Charges		11.6124								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		0.9700	03/04/2010							
Demand Rate/US$		$11.8847		$0.3834	$0.3962	$0.3834	$0.3834	$0.3962	$0.3834	$0.3876
Peaking										
Granite Ridge Demand			per contract							
Storage										
Dominion - Demand	GSS 300076	$1.8773	36rd Rev Sheet No. 35	$0.0606	$0.0626	$0.0606	$0.0606	$0.0626	$0.0606	$0.0614
Dominion - Capacity	GSS 300076	$0.0145	36rd Rev Sheet No. 35	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8918		$0.0610	$0.0631	$0.0610	$0.0610	$0.0631	$0.0610	$0.0618
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet 5	$0.2071	$0.2140	$0.2071	$0.2071	$0.2140	$0.2071	$0.2098
National Fuel - Demand	FSS-1 2357	$2.1556	17th Rev. Sheet No. 10	$0.0695	$0.0719	$0.0695	$0.0695	$0.0719	$0.0695	$0.0705
National Fuel - Capacity	FSS-1 2357	$0.0432	17th Rev. Sheet No. 10	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014
		$2.1988		$0.0709	$0.0733	$0.0709	$0.0709	$0.0733	$0.0709	$0.0719
Tenn Gas Pipeline	FS-MA	$1.1500	17th Rev Sheet No. 27	$0.0371	$0.0383	$0.0371	$0.0371	$0.0383	$0.0371	$0.0376
Tenn Gas Pipeline - Space	FS-MA	$0.0185	17th Rev Sheet No. 27	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006
		$1.1685		$0.0377	$0.0390	$0.0377	$0.0377	$0.0390	$0.0377	$0.0382

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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	$0.0664	$0.0219	($0.0118)	$0.0024	-	$1.8773
	Storage Capacity	$0.0145	-	-	-	-	-	$0.0145
	Injection Charge	$0.0154	-	$0.0066	$0.0001	($0.0011)	-	$0.0210
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0011)	$0.0019	$0.0163
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0005	-	-	$0.0051
	Demand Charge Adjustment	$21.5808	$0.7968	$0.2628	($0.1416)	$0.0288	-	$22.5276
	From Customers Balance	$0.6163	$0.0147	$0.0048	($0.0025)	($0.0006)	$0.0019	$0.6346
GSS-E [2], [4]								
===	Storage Demand	$2.2113	$0.0664	$0.0219	($0.0118)	$0.0024	-	$2.2902
	Storage Capacity	$0.0369	-	-	-	-	-	$0.0369
	Injection Charge	$0.0154	-	$0.0066	$0.0001	($0.0011)	-	$0.0210
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0011)	$0.0019	$0.0163
	Authorized Overruns	$1.0657	$0.0147	$0.0048	($0.0025)	($0.0006)	$0.0019	$1.0840
ISS [2]								
======	ISS Capacity	$0.0736	$0.0022	$0.0007	($0.0004)	$0.0001	-	$0.0762
	Injection Charge	$0.0154	-	$0.0066	$0.0001	($0.0011)	-	$0.0210
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0011)	$0.0019	$0.0163
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0147	$0.0048	($0.0025)	($0.0006)	$0.0019	$0.6346
	Excess Injection Charge	$0.2245	-	$0.0066	$0.0001	($0.0011)	-	$0.2301

[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 $0.6183.
Daily Capacity Release Rate for GSS-E per Dt is $1.0677.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.

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	0.0019	$0.1187
		(Min)	0.0000	0.0019	$0.0019
	Overrun	(Max)	0.1168	0.0019	$0.1187
		(Min)	0.0000	0.0019	$0.0019
IG	Commodity	(Max)	0.1800	-	$0.1800
		(Min)	0.0069	-	$0.0069
FG	Reservation	(Max)	0.0000	-	$0.0000
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0069	0.0019	$0.0088
		(Min)	0.0069	0.0019	$0.0088
	Overrun	(Max)	0.1800	0.0019	$0.1819
		(Min)	0.1800	0.0019	$0.1819
X-58	Conversion Surcharge				
	Reservation	(Max)	0.1221	-	$0.1221
		(Min)	-	-	-
	Commodity	(Max)	-	-	-
		(Min)	-	-	-
W-1	Commodity	(Max)	0.0252	0.0019	$0.0271
		(Min)	0.0000	-	$0.0000
	Overrun	(Max)	0.0252	0.0019	$0.0271
		(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	0.0019	$0.0551
		(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	0.0019	$0.0082
		(Min)	0.0063	0.0019	$0.0082
	Overrun	(Max)	0.1168	0.0019	$0.1187
		(Min)	0.0063	0.0019	$0.0082
	Maximum Volumetric Rate		0.1168	0.0019	$0.1187

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	0.0019	$0.0158
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/			0.0702	0.0019	$0.0721
	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	0.0019	$1.0654
		(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	0.0019	$0.0158
		(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	0.0019	$0.0158
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/			0.0709	0.0019	$0.0728
	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	0.0019	$0.0594
		(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 Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ 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 $00.0019 $00.0019

-- Minimum $00.0000 $00.0019 $00.0019

FT-FLEX Recourse Reservation Rate

--Maximum $18.3920 ------- $18.3920

--Minimum $00.0000 ------- $00.0000

Recourse Usage Rate

--Maximum $00.2962 $00.0019 $00.2981

--Minimum $00.0000 $00.0019 $00.0019

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

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
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		$0.0019			$0.0019	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

T ans o a ion Tolls
Approved Final Mainline Tolls effective January 1, 2010

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

Storage Transportation Service

1	3 1 5 3	0 00330
2	23 3 333	0 03242
3	3	0 01154
4	5 250	0 00 2
5	5 15 3	0 00 5
	10 4241	0 0135
	1 1 50	0 00012
	3 52250	0 003 3
	030 3	0 0100
10	10 2 33	0 013 4

Enhanced Capacity Release

11	0 03

Delivery Pressure

				1
12	1	0 11	0 00000	0 003 5
13	2	0 1221	0 00000	0 00402
14		0 0 33	0 00000	0 0020
15		0 1 5	0 00000	0 00554
1		0 5 2	0 00000	0 025 3
1		0 1314	0 00000	0 02 3
1		1 55	0 03	0 102 0

1

FT TFT an n e i le T ans o a ion Tolls
Approved Final Mainline Tolls effective January 1, 2010

ine o	eceipt oint	elivery point	e and Toll J M	o odity Toll J	FT, TFT Mini u Tolls 100 F FT Tolls J	1 T id Floor 110 FT Tolls J
1	nion a n	erson 2	2 2	0 00000	0 1	0
2	nion a n	t lair	1 12	0 00000	0 0	0 0 21
	nion a n	a n port	1 0 0	0 00000	0 0	0 0
	nion a n	ir all	0	0 00 0	0 1 2	0 1
	nion a n	ia ara Falls	0	0 00 0	0 1	0 20
	nion a n	ippa a	00	0 00	0 1 0	0 20
	nion a n	ro uois	10 2	0 01 1	0 00	0 0 0
	nion a n	orn all	11 1 01	0 01	0 0	0 2
	nion a n	apierville	1 2	0 01	0 0	0 1
10	nion a n	ilips ur	1 010 1	0 01	0	0 2
11	nion a n	ast ereford	1	0 022	0 1	0 1
12	nion a n	el yn	0 2	0 00000	1 01	1 11
1	n rid e A	press		0 0	1 20	1 2
1	n rid e A	Trans as A	100	0 0	1 20	1 2
1	n rid e A	entra A	1	0 0	1 20	1 2 1
1	n rid e A	entra M A	1	0 0 0	1 0	1 1
1	n rid e A	entrat M A	2 0	0 0 1 0	1 02	1 12 2
1	n rid e A	nion A	2 0	0 0 1	0 0	0
1	n rid e A	ipi on A	21 0 1	0 02	0 211	0 2
20	n rid e A	nion A	1	0 011	0 02	0 2
21	n rid e A	alstoc A	1 1	0 02 1	0 2	0 22
22	n rid e A	Tunis A	12 2	0 01 20	0	0
2	n rid e A	M T A	0 2	0 010	0 0	0
2	n rid e A	nion M A	1 0	0 01	0	0 1
2	n rid e A	nion A	2	0 00	0 12	0 1
2	n rid e A	nion A	2 1	0 001	0 0	0 0 20
2	n rid e A	n rid e A	1 0 0	0 00000	0 0	0 0
2	n rid e A	nion A	1	0 00	0 1 2	0 20
2	n rid e A	n rid e A	00	0 00	0 2	0 2
0	n rid e A	M T A	00	0 012	0 1	0
1	n rid e A	A	1 2 1	0 00	0 1	0 1 0
2	n rid e A	ort ay Junction	20	0 00	0 21	0 2 2
	n rid e A	n rid e A		0 00 0	0 1 0	0 20
	n rid e A	nion A		0 00 2	0 1 0	0 21
	n rid e A	pruce	2 0 2	0 0 1	1 021	1 12
	n rid e A	erson 1	2 1	0 0 0	0	1 0
	n rid e A	erson 2	2 1	0 0 0	0	1 0
	n rid e A	t lair	221	0 00 2	0 1 2	0 21 0
	n rid e A	a n port		0 00 0	0 1 0	0 20
0	n rid e A	ir all	2	0 00222	0 0	0 0
1	n rid e A	ia ara Falls	00	0 00 2	0 12	0 1 1
2	n rid e A	ippa a	2 1	0 00	0 12 2	0 1
	n rid e A	ro uois	011	0 00 2	0 2 1	0 2 0
	n rid e A	orn all		0 00	0 2	0 2 2
	n rid e A	apierville	2	0 012	0	0
	n rid e A	ilips ur	10 1	0 01 2	0	0 2
	n rid e A	ast ereford	12 1 2	0 01 2	0 0	0
	n rid e A	el yn	2	0 0 0	1 22	1 1
	n rid e A	press	10	0 0	1 22	1 2
0	n rid e A	Trans as A	10	0 0 2	1 1	1 2
1	n rid e A	entra A		0 0 1	1 2	1 0
2	n rid e A	entra M A	2 0	0 0	1 12 2	1 2
	n rid e A	entrat M A	11	0 0 1	1 2	1 01
	n rid e A	nion A	2 2 0	0 0 1	0 0	0 1
	n rid e A	ipi on A	21 0 10	0 02	0 20	0 2
	n rid e A	nion A	10 0 2	0 01 1	0 2	0
	n rid e A	alstoc A	1 10 2	0 021 2	0 12	0 0
	n rid e A	Tunis A	12 221	0 01 1	0 1 0	0
	n rid e A	M T A	1 1	0 012	0 2	0 1
0	n rid e A	nion M A	20 1	0 02 2	0 0	0
1	n rid e A	nion A	1	0 0121	0 211	0 2
2	n rid e A	nion A	21	0 010	0 2	0 1
	n rid e A	n rid e A	00	0 00	0 2	0 2
	n rid e A	nion A	0	0 00	0 12	0 1 2
	n rid e A	n rid e A	1 0 0	0 00000	0 0	0 0
	n rid e A	M T A	1	0 00 11	0 1 10	0 1 1
	n rid e A	A	012	0 00 0	0 1 1	0 1
	n rid e A	ort ay Junction	2 2	0 00	0 2	0 2 1
	n rid e A	n rid e A	11 2 1	0 01 0	0 20	[illegible]

RATES AND STATISTICS

Exchange Rates

Text + – R Print

Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 04 Mar 2010

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:	0.97 CONVERT
Exchange rate:	0.9700

Summary:

On 04 Mar 2010, 1.00 Canadian dollar(s) = 0.97 U.S. dollar(s), at an exchange rate of 0.9700 (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 and 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.

1	**ENERGY NORTH NATURAL GAS, INC.**									
2	**d/b/a National Grid NH**									
3	**Off Peak 2010 Summer Cost of Gas Filing**									
4	**Supply and Commodity Costs, Volumes and Rates**									
5										Off-Peak
6	For Month of:		Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8										
9	**Supply and Commodity Costs**									
10										
11	**Pipeline Gas:**									
12		Dawn Supply	ln 63 * ln 102							
13		Niagara Supply	ln 64 * ln 107							
14		TGP Supply (Direct)	ln 65 * ln 123							
15		Dracut Supply 1 - Baseload	ln 66 * ln 112							
16		Dracut Supply 2 - Swing	ln 67 * ln 117							
17		City Gate Delivered Supply	ln 68 * ln 129							
18		LNG Truck	ln 69 * ln 131							
19		Propane Truck	ln 70 * ln 133							
20		PNGTS	ln 71 * ln 138							
21		Granite Ridge	ln 72 * ln 143							
22										
23		Subtotal Pipeline Gas Costs		$ 2,403,401	$ 1,887,353	$ 1,893,297	$ 2,040,425	$ 2,259,585	$ 3,828,631	$ 14,312,692
24										
25	**Volumetric Transportation Costs**									
26		Dawn Supply	ln 63 * ln 175							
27		Niagara Supply	ln 64 * ln 186							
28		TGP Supply (Direct)	ln 65 * ln 213							
29		Dracut Supply 1 - Baseload	ln 66 * ln 234							
30		Dracut Supply 2 - Swing	ln 67 * ln 234							
31		City Gate Delivered Supply	ln 68 * ln 234							
32		TGP Storage - Withdrawals	ln 77 * ln 165							
33										
34	**Total Volumetric Transportation Costs**			$ 161,655	$ 192,609	$ 191,703	$ 74,520	$ 79,133	$ 130,402	$ 830,022
35										
36	**Less - Gas Refill:**									
37		LNG Truck	ln 86 * ln 150							
38		Propane	ln 87 * ln 151							
39		TGP Storage Refill	ln 88 * ln 121							
40		Storage Refill (Trans.)	ln 88 * ln 213							
41										
42		Subtotal Refills		$ (479,579)	$ (459,497)	$ (467,562)	$ (473,111)	$ (476,007)	$ (485,378)	$ (2,841,135)
43										
44	**Total Supply & Pipeline Commodity Costs**		ln 23 + ln 34 + ln 42	$ 2,085,476	$ 1,620,466	$ 1,617,438	$ 1,641,833	$ 1,862,711	$ 3,473,655	$ 12,301,578
45										
46	**Storage Gas:**									
47		TGP Storage - Withdrawals	ln 77 * ln 157	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48										
49	**Produced Gas:**									
50		LNG Vapor	ln 80 * ln 145							
51		Propane	ln 81 * ln 147							
52										
53	**Total Produced Gas**		ln 50 + ln 51	$ 13,216	$ 12,651	$ 12,972	$ 12,906	$ 12,446	$ 12,854	$ 77,045
54										
55										
56	**Total Commodity Gas & Trans. Costs**		ln 44 + ln 47 + ln 53	$ 2,098,692	$ 1,633,116	$ 1,630,410	$ 1,654,739	$ 1,875,158	$ 3,486,509	$ 12,378,623
57										
58				**THIS PAGE HAS BEEN REDACTED**						

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Line		Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Off-Peak May - Oct
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Off Peak 2010 Summer Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Off-Peak
6	For Month of:	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
59									Off-Peak
60	**Volumes (Therms)**								
61									
62	**Pipeline Gas:**	See Schedule 11A							
63	Dawn Supply		-	-	-	-	-	-	-
64	Niagara Supply		-	-	-	-	-	-	-
65	TGP Supply (Direct)		2,882,508	3,899,955	3,836,489	831,390	831,390	1,313,940	13,595,672
66	Dracut Supply 1 - Baseload		-	-	-	-	-	-	-
67	Dracut Supply 2 - Swing		1,940,115	-	-	2,995,755	3,390,725	5,722,244	14,048,838
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		79,674	23,970	24,769	24,769	23,970	24,769	201,922
70	Propane Truck		-	-	-	-	-	-	-
71	PNGTS		38,588	27,250	26,073	26,855	30,783	47,974	197,523
72	Granite Ridge		-	-	-	-	-	-	-
73									
74	Subtotal Pipeline Volumes		4,940,885	3,951,176	3,887,331	3,878,769	4,276,868	7,108,927	28,043,955
75									
76	**Storage Gas:**								
77	TGP Storage		-	-	-	-	-	-	-
78									
79	**Produced Gas:**								
80	LNG Vapor		24,769	23,970	24,769	24,769	23,970	24,769	147,017
81	Propane		-	-	-	-	-	-	-
82									
83	Subtotal Produced Gas		24,769	23,970	24,769	24,769	23,970	24,769	147,017
84									
85	**Less - Gas Refill:**								
86	LNG Truck		(79,674)	(23,970)	(24,769)	(24,769)	(23,970)	(24,769)	(201,922)
87	Propane		-	-	-	-	-	-	-
88	TGP Storage Refill		(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(4,988,340)
89									
90	Subtotal Refills		(911,064)	(855,360)	(856,159)	(856,159)	(855,360)	(856,159)	(5,190,262)
91									
92	**Total Sendout Volumes**		4,054,590	3,119,786	3,055,941	3,047,379	3,445,478	6,277,537	23,000,711
93									
94									
95									

00000030

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

Line									Off-Peak
5									
6	For Month of:	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
96	**Gas Costs and Volumetric Transportation Rates**								Average Rate
97									
98	**Pipeline Gas:**								
99	**Dawn Supply**								
100	NYMEX Price	Sch 7, ln 10/10							
101	Basis Differential								
102	**Net Commodity Costs**								
103									
104	**Niagara Supply**								
105	NYMEX Price	Sch 7, ln 10/10							
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Dracut Supply 1 - Baseload**								
110	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10							
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 2 - Swing**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10							
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119									
120	**TGP Supply (Direct)**								
121	NYMEX Price	Sch 7, ln 10/10	$0.4818	$0.4892	$0.4976	$0.5037	$0.5073	$0.5171	
122	Basis Differential								
123	**Net Commodity Costs**								
124									
125									
126	**City Gate Delivered Supply**								
127	NYMEX Price	Sch 7, ln 10/10							
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131	**LNG Truck**	Sch 7, ln 10/10	**$0.4818**	**$0.4892**	**$0.4976**	**$0.5037**	**$0.5073**	**$0.5171**	**$0.4994**
132									
133	**Propane Truck**	NYMEX - Propane	**$0.7400**	**$0.7490**	**$0.7560**	**$0.7660**	**$0.7770**	**$0.7880**	**$0.7627**
134									
135	**PNGTS**								
136	NYMEX Price	Sch 7, ln 10/10							
137	Additional Cost								
138	**Net Commodity Cost**								
139									
140	**Granite Ridge**								
141	NYMEX Price	Sch 7, ln 10/10							
142	Additional Cost								
143	**Net Commodity Cost**								
144									
145	**LNG Vapor (Storage)**	Sch 13, ln 122 /10	**$0.5336**	**$0.5278**	**$0.5237**	**$0.5210**	**$0.5192**	**$0.5190**	**$0.5240**
146									
147	**Propane**	Sch 13, ln 84 /10	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**	**$1.4621**
148									
149	**Storage Refill:**								
150	**LNG Truck**	ln 131	**$0.4818**	**$0.4892**	**$0.4976**	**$0.5037**	**$0.5073**	**$0.5171**	**$0.4994**
151	**Propane**	ln 133	**$0.7400**	**$0.7490**	**$0.7560**	**$0.7660**	**$0.7770**	**$0.7880**	**$0.7627**
152									
153									

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00000031

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

Ln									
5									Off-Peak
6	For Month of:	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									
155									Average Rate
156	**Dawn Supply Volumetric Transportation Charge**								
157	**Commodity Costs**	ln 102							
158									
159	TransCanada - Commodity Rate/GJ	Union Dawn to Iroquois	$0.00141	$0.00141	$0.00141	$0.00141	$0.00141	$0.00141	$0.00141
160	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
161	Conversion Rate to US$	03/04/2010	0.970	0.970	0.970	0.970	0.970	0.970	0.9700
162	Commodity Rate/US$	ln 159 x ln 160 x ln 161	$0.00145	$0.00145	$0.00145	$0.00145	$0.00145	$0.00145	$0.00145
163	TransCanada Fuel %	Union Dawn to Iroquois	1.49%	1.03%	1.59%	1.40%	0.69%	0.94%	1.19%
164	TransCanada Fuel * Percentage	ln 157 x ln 163	$0.00718	$0.00504	$0.00791	$0.00705	$0.00350	$0.00486	$0.00592
165	Subtotal TransCanada		**$0.00862**	**$0.00648**	**$0.00936**	**$0.00850**	**$0.00495**	**$0.00631**	**$0.00737**
166	IGTS - Z1 RTS Commodity	31st Rev Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
167	IGTS - Z1 RTS ACA Rate Commodity	24th Rev Sheet 4A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
168	IGTS - Z1 RTS Deferred Asset Surcharge	24th Rev Sheet 4A	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
169	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**
170	TGP NET-NE - Comm. Segments 3 & 4	43nd Rev Sheet No. 26B	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
171	IGTS -Fuel Use Factor - Percentage	24th Rev Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
172	IGTS -Fuel Use Factor - Fuel * Percentage	ln 157 x ln 171	**$0.00482**	**$0.00489**	**$0.00498**	**$0.00504**	**$0.00507**	**$0.00517**	**$0.00499**
173	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%
174	TGP NET-284 -Fuel Use Factor - Fuel * %	ln 157 x ln 173	**$0.00742**	**$0.00753**	**$0.00766**	**$0.00776**	**$0.00781**	**$0.00796**	**$0.00769**
175	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.02157**	**$0.01962**	**$0.02271**	**$0.02200**	**$0.01854**	**$0.02015**	**$0.02077**
176									
177									
178	**Niagara Supply Volumetric Transportation Charge**								
179	**Commodity Costs**	Ln 107							
180									
181	TGP FTA - FTA Z 5-6 Comm. Rate	21st Rev Sheet No. 23A							
182	TGP FTA - FTA Z 5-6 - ACA Rate	21st Rev Sheet No. 23A							
183	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
184	TGP FTA Fuel Charge % Z 5-6	3rd Rev Sheet No. 29							
185	TGP FTA Fuel * Percentage	ln 179 x ln 184							
186	**Total Volumetric Transportation Rate - Niagra Supply**								
187									
188									
189									

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Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Off Peak 2010 Summer Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Off-Peak
6	For Month of:	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
190									
191									
192	**TGP Direct Volumetric Transportation Charge**								Average Rate
193	**Commodity Costs**	Ln 121	**$0.4818**	**$0.4892**	**$0.4976**	**$0.5037**	**$0.5073**	**$0.5171**	**$0.4994**
194									
195	TGP - Max Comm. Base Rate - Z 0-6	21st Rev Sheet No. 23A	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608	$0.01608
196	TGP - Max Commodity ACA Rate - Z 0-6	21st Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
197	Subtotal TGP - Max Comm. Rate Z 0-6		$0.01627	$0.01627	$0.01627	$0.01627	$0.01627	$0.01627	$0.01627
198	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
199	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**
200	TGP - Max Comm. Base Rate - Z 1-6	21st Rev Sheet No. 23A	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503	$0.01503
201	TGP - Max Commodity ACA Rate - Z 1-6	21st Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
202	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.01522	$0.01522	$0.01522	$0.01522	$0.01522	$0.01522	$0.01522
203	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
204	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**
205	TGP - Fuel Charge % - Z 0 -6	3rd Rev Sheet No. 29	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%
206	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
207	Prorated TGP Fuel Charge % - Z 0-6		2.42%	2.42%	2.42%	2.42%	2.42%	2.42%	2.42%
208	TGP - Fuel Charge % - Z 1 -6	3rd Rev Sheet No. 29	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
209	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
210	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
211	TGP - Fuel Charge % - Z 0-6	In 193 x In 207	**$0.01165**	**$0.01183**	**$0.01204**	**$0.01218**	**$0.01227**	**$0.01251**	**$0.01208**
212	TGP - Fuel Charge % - Z 1-6	In 193 x In 210	**$0.02166**	**$0.02199**	**$0.02237**	**$0.02264**	**$0.02281**	**$0.02325**	**$0.02245**
213	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04888**	**$0.04939**	**$0.04997**	**$0.05039**	**$0.05064**	**$0.05132**	**$0.05010**
214									
215	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
216	**Commodity Costs**	Ln 121	**$0.4818**	**$0.4892**	**$0.4976**	**$0.5037**	**$0.5073**	**$0.5171**	**$0.4994**
217									
218	TGP - Max Comm. Base Rate - Z 6-6	21st Rev Sheet No. 23A	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642	$0.00642
219	TGP - Max Commodity ACA Rate - Z 6-6	21st Rev Sheet No. 23A	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019	$0.00019
220	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**
221	TGP - Fuel Charge % - Z 6-6	3rd Rev Sheet No. 29	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%
222	TGP - Fuel Charge	In 216 x In 221	**$0.00410**	**$0.00416**	**$0.00423**	**$0.00428**	**$0.00431**	**$0.00440**	**$0.00425**
223	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.01071**	**$0.01077**	**$0.01084**	**$0.01089**	**$0.01092**	**$0.01101**	**$0.01086**
224									
225									
226	**TGP Dracut**								
227	**Commodity Costs - NYMEX Price**	Ln 112							
228									
229	TGP - Trans Charge - Comm. - Z 6-6	21st Rev Sheet No. 23A							
230	TGP - Trans Charge - ACA Rate - Z6-6	21st Rev Sheet No. 23A							
231	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
232	TGP - Fuel Charge % - Z 6-6	3rd Rev Sheet No. 29							
233	TGP - Fuel Charge	In 227 x In 232							
234	**Total Volumetric Transportation Rate - TGP Dracut**								
235									
236									

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--------------- 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	0.0019
DEFERRED ASSET SURCHARGE:	
Commodity	
Zone 1	0.0003
Zone 2	0.0002
Inter-Zone	0.0005
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

DELIVERY ZONE

RECEIPT 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/

DELIVERY ZONE

RECEIPT 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/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0458		$0.0688	$0.0899	$0.0997	$0.1137	$0.1250	$0.1627
L		$0.0305						
1	$0.0688		$0.0591	$0.0795	$0.0893	$0.1033	$0.1145	$0.1522
2	$0.0899		$0.0795	$0.0452	$0.0549	$0.0700	$0.0802	$0.1178
3	$0.0997		$0.0893	$0.0549	$0.0385	$0.0682	$0.0784	$0.1161
4	$0.1148		$0.1044	$0.0700	$0.0682	$0.0420	$0.0478	$0.0853
5	$0.1250		$0.1145	$0.0802	$0.0784	$0.0478	$0.0446	$0.0784
6	$0.1627		$0.1522	$0.1178	$0.1161	$0.0853	$0.0784	$0.0661

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

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		$0.0019			$0.0019	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.

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

FT TFT an n e i le T ans o a ion Tolls
Approved Final Mainline Tolls effective January 1, 2010

ine o	eceipt oint	elivery point	e and Toll J M	o odity Toll J	FT, TFT Mini u Tolls 100 F FT Tolls J	1 T id Floor 110 FT Tolls J
1	nion a n	erson 2	2 2	0 00000	0 1	0
2	nion a n	t lair	1 12	0 00000	0 0	0 0 21
	nion a n	a n port	1 0 0	0 00000	0 0	0 0
	nion a n	ir all	0	0 00 0	0 1 2	0 1
	nion a n	ia ara Falls	0	0 00 0	0 1	0 20
	nion a n	ippa a	00	0 00	0 1 0	0 20
	nion a n	ro uois	10 2	0 01 1	0 00	0 0 0
	nion a n	orn all	11 1 01	0 01	0 0	0 2
	nion a n	apierville	1 2	0 01	0 0	0 1
10	nion a n	ilips ur	1 010 1	0 01	0	0 2
11	nion a n	ast ereford	1	0 022	0 1	0 1
12	nion a n	el yn	0 2	0 00000	1 01	1 11
1	n rid e A	press		0 0	1 20	1 2
1	n rid e A	Trans as A	100	0 0	1 20	1 2
1	n rid e A	entra A	1	0 0	1 20	1 2 1
1	n rid e A	entra M A	1	0 0 0	1 0	1 1
1	n rid e A	entrat M A	2 0	0 0 1 0	1 02	1 12 2
1	n rid e A	nion A	2 0	0 0 1	0 0	0
1	n rid e A	ipi on A	21 0 1	0 02	0 211	0 2
20	n rid e A	nion A	1	0 011	0 02	0 2
21	n rid e A	alstoc A	1 1	0 02 1	0 2	0 22
22	n rid e A	Tunis A	12 2	0 01 20	0	0
2	n rid e A	M T A	0 2	0 010	0 0	0
2	n rid e A	nion M A	1 0	0 01	0	0 1
2	n rid e A	nion A	2	0 00	0 12	0 1
2	n rid e A	nion A	2 1	0 001	0 0	0 0 20
2	n rid e A	n rid e A	1 0 0	0 00000	0 0	0 0
2	n rid e A	nion A	1	0 00	0 1 2	0 20
2	n rid e A	n rid e A	00	0 00	0 2	0 2
0	n rid e A	M T A	00	0 012	0 1	0
1	n rid e A	A	1 2 1	0 00	0 1	0 1 0
2	n rid e A	ort ay Junction	20	0 00	0 21	0 2 2
	n rid e A	n rid e A		0 00 0	0 1 0	0 20
	n rid e A	nion A		0 00 2	0 1 0	0 21
	n rid e A	pruce	2 0 2	0 0 1	1 021	1 12
	n rid e A	erson 1	2 1	0 0 0	0	1 0
	n rid e A	erson 2	2 1	0 0 0	0	1 0
	n rid e A	t lair	221	0 00 2	0 1 2	0 21 0
	n rid e A	a n port		0 00 0	0 1 0	0 20
0	n rid e A	ir all	2	0 00222	0 0	0 0
1	n rid e A	ia ara Falls	00	0 00 2	0 12	0 1 1
2	n rid e A	ippa a	2 1	0 00	0 12 2	0 1
	n rid e A	ro uois	011	0 00 2	0 2 1	0 2 0
	n rid e A	orn all		0 00	0 2	0 2 2
	n rid e A	apierville	2	0 012	0	0
	n rid e A	ilips ur	10 1	0 01 2	0	0 2
	n rid e A	ast ereford	12 1 2	0 01 2	0 0	0
	n rid e A	el yn	2	0 0 0	1 22	1 1
	n rid e A	press	10	0 0	1 22	1 2
0	n rid e A	Trans as A	10	0 0 2	1 1	1 2
1	n rid e A	entra A		0 0 1	1 2	1 0
2	n rid e A	entra M A	2 0	0 0	1 12 2	1 2
	n rid e A	entrat M A	11	0 0 1	1 2	1 01
	n rid e A	nion A	2 2 0	0 0 1	0 0	0 1
	n rid e A	ipi on A	21 0 10	0 02	0 20	0 2
	n rid e A	nion A	10 0 2	0 01 1	0 2	0
	n rid e A	alstoc A	1 10 2	0 021 2	0 12	0 0
	n rid e A	Tunis A	12 221	0 01 1	0 1 0	0
	n rid e A	M T A	1 1	0 012	0 2	0 1
0	n rid e A	nion M A	20 1	0 02 2	0 0	0
1	n rid e A	nion A	1	0 0121	0 211	0 2
2	n rid e A	nion A	21	0 010	0 2	0 1
	n rid e A	n rid e A	00	0 00	0 2	0 2
	n rid e A	nion A	0	0 00	0 12	0 1 2
	n rid e A	n rid e A	1 0 0	0 00000	0 0	0 0
	n rid e A	M T A	1	0 00 11	0 1 10	0 1 1
	n rid e A	A	012	0 00 0	0 1 1	0 1
	n rid e A	ort ay Junction	2 2	0 00	0 2	0 2 1
	n rid e A	n rid e A	11 2 1	0 01 0	0 20	[illegible]

TransCanada Fuel Ratios

May 2009

Pressure Point	Pressure (%)
	4
	0
	0
	0 69
	0 00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
		0.3010	1.49	0 80

June 2009

Pressure Point	Pressure (%)
	4
	0
	0
	0 69
	0 00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
		0.3010	1.03	0 34

July 2009

Pressure Point	Pressure (%)
	4
	0
	0
	0 69
	0 00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
		0.3010	1.59	0 90

August 2009

Pressure Point	Pressure (%)
	4
	0
	0
	0 69
	0 00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
		0.3010	1.40	0 7

September 2009

Pressure Point	Pressure (%)
	4
	0
	0
	0 69
	0 00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
		0.3010	0.69	0 00

October 2009

Pressure Point	Pressure (%)
	4
	0
	0
	0 69
	0 00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
		0.3010	0.94	0

Rates and Statistics

- Daily Digest
- Exchange rates
- Interest rates
- Price indexes
- Indicators
- Related information

RATES AND STATISTICS

Exchange Rates

Text + – R Print

Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 04 Mar 2010

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:	**0.97** CONVERT
Exchange rate:	0.9700

Summary:

On 04 Mar 2010, 1.00 Canadian dollar(s) = 0.97 U.S. dollar(s), at an exchange rate of 0.9700 (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** and **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.

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

Line		Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct Off Peak Strip Average
5									
6	For Month of:	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	
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 ln 192	$4.8179	$4.8919	$4.9759	$5.0367	$5.0728	$5.1709	$ 4.9944
11		June trigger							
12		July trigger							
13		August Trigger							
14		September Trigger							
15		October Trigger							
16									
17									
18									
19	**II. Development of Hedging Costs and Savings**								
20									May - Oct
21	**TGP (Direct) Volumes**								Total
22	Hedged Volumes (Dth)	ln 76	190,000	-	-	-	-	210,000	400,000
23	Market Priced Volumes (Dth)	ln 24 - ln 22	212,982	309,582	303,117	302,261	342,151	415,277	1,885,369
24	Total Volumes (Dth)	Sch 6, lns 74 + 90 / 10	402,982	309,582	303,117	302,261	342,151	625,277	2,285,369
25	Percentage of Volumes Hedged	ln 22 / ln 24	47.15%					33.59%	17.50%
26									
27	Hedge Price	ln 162	$ 7.1669	$ -	$ -	$ -	$ -	$ 6.0475	$ 6.5792
28	NYMEX Price	ln 10	$ 4.8179	$ -	$ -	$ -	$ -	$ 5.1709	$ 5.0033
29									
30	Hedged Volumes at Hedged Price	ln 22 * ln 27	$ 1,361,712	$ -	$ -	$ -	$ -	$ 1,269,985	$ 2,631,697
31	Less Hedged Volumes at NYMEX	ln 22 * ln 28	915,407	-	-	-	-	1,085,896	2,001,303
32	Hedge (Savings)/Loss	ln 30 - ln 31	$ 446,305	$ -	$ -	$ -	$ -	$ 184,089	$ 630,394
33									
34									

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

Line						Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct Off Peak Strip Average
5													
6	For Month of:												
35													
36													
37													May - Oct
38	Hedged Volumes (Dth)												Total
39	Hedge:	1	Trade Date	06-Jun-08	Swaps								
40	Hedge:	2	Trade Date	16-May-08	Swaps								
41	Hedge:	3	Trade Date	20-Jun-08	Swaps								
42	Hedge:	4	Trade Date	25-Jul-08	Swaps								
43	Hedge:	5	Trade Date	08-Aug-08	Swaps								
44	Hedge:	6	Trade Date	25-Aug-08	Swaps								
45	Hedge:	7	Trade Date	05-Sep-08	Swaps								
46	Hedge:	8	Trade Date	07-Nov-08	Swaps								
47	Hedge:	9	Trade Date	21-Nov-08	Swaps								
48	Hedge:	10	Trade Date	29-Jan-09	Swaps								
49	Hedge:	11	Trade Date	23-Mar-09	Swaps								
50	Hedge:	12	Trade Date	26-Mar-09	Swaps								
51	Hedge:	13	Trade Date	09-Apr-09	Swaps								
52	Hedge:	14	Trade Date	30-Apr-09	Swaps								
53	Hedge:	15	Trade Date	12-Jun-09	Swaps								
54	Hedge:	16	Trade Date	25-Jun-09	Swaps								
55	Hedge:	17	Trade Date	10-Jul-09	Swaps								
56	Hedge:	18	Trade Date	21-Aug-09	Swaps								
57	Hedge:	19	Trade Date	15-May-09	Swaps								
58	Hedge:	20	Trade Date	29-May-09	Swaps								
59	Hedge:	21	Trade Date	12-Jun-09	Swaps								
60	Hedge:	22	Trade Date	25-Jun-09	Swaps								
61	Hedge:	23	Trade Date	10-Jul-09	Swaps								
62	Hedge:	24	Trade Date	27-Jul-09	Swaps								
63	Hedge:	25	Trade Date	07-Aug-09	Swaps								
64	Hedge:	26	Trade Date	21-Aug-09	Swaps								
65	Hedge:	27	Trade Date	11-Sep-09	Swaps								
66	Hedge:	28	Trade Date	25-Sep-09	Swaps								
67	Hedge:	29	Trade Date	09-Oct-09	Swaps								
68	Hedge:	30	Trade Date	23-Nov-09	Swaps								
69	Hedge:	31	Trade Date	30-Nov-09	Swaps								
70	Hedge:	32	Trade Date	14-Dec-09	Swaps								
71	Hedge:	33	Trade Date	30-Dec-09	Swaps								
72	Hedge:	34	Trade Date	15-Jan-10	Swaps								
73	Hedge:	35	Trade Date	29-Jan-10	Swaps								
74	Hedge:	36	Trade Date	12-Feb-10	Swaps								
75	Hedge:	37	Trade Date	26-Feb-10	Swaps								
76							190,000	-	-	-	-	210,000	400,000
77													
78													

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Line	Description			Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct Off Peak Strip Average
1	**ENERGY NORTH NATURAL GAS, INC.**										
2	**d/b/a National Grid NH**										
3	**Off Peak 2010 Summer Cost of Gas Filing**										
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**										
5											
6	For Month of:										
79	Strike Price										
80											May - Oct
81	Hedge : 1	Trade Date	06-Jun-08	Swaps							
82	Hedge : 2	Trade Date	16-May-08	Swaps							
83	Hedge : 3	Trade Date	20-Jun-08	Swaps							
84	Hedge : 4	Trade Date	25-Jul-08	Swaps							
85	Hedge : 5	Trade Date	08-Aug-08	Swaps							
86	Hedge : 6	Trade Date	25-Aug-08	Swaps							
87	Hedge : 7	Trade Date	05-Sep-08	Swaps							
88	Hedge : 8	Trade Date	07-Nov-08	Swaps							
89	Hedge : 9	Trade Date	21-Nov-08	Swaps							
90	Hedge : 10	Trade Date	29-Jan-09	Swaps							
91	Hedge : 11	Trade Date	23-Mar-09	Swaps							
92	Hedge : 12	Trade Date	26-Mar-09	Swaps							
93	Hedge : 13	Trade Date	09-Apr-09	Swaps							
94	Hedge : 14	Trade Date	30-Apr-09	Swaps							
95	Hedge : 15	Trade Date	12-Jun-09	Swaps							
96	Hedge : 16	Trade Date	25-Jun-09	Swaps							
97	Hedge : 17	Trade Date	10-Jul-09	Swaps							
98	Hedge : 18	Trade Date	21-Aug-09	Swaps							
99	Hedge : 19	Trade Date	15-May-09	Swaps							
100	Hedge : 20	Trade Date	29-May-09	Swaps							
101	Hedge : 21	Trade Date	12-Jun-09	Swaps							
102	Hedge : 22	Trade Date	25-Jun-09	Swaps							
103	Hedge : 23	Trade Date	10-Jul-09	Swaps							
104	Hedge : 24	Trade Date	27-Jul-09	Swaps							
105	Hedge : 25	Trade Date	07-Aug-09	Swaps							
106	Hedge : 26	Trade Date	21-Aug-09	Swaps							
107	Hedge : 27	Trade Date	11-Sep-09	Swaps							
108	Hedge : 28	Trade Date	25-Sep-09	Swaps							
109	Hedge : 29	Trade Date	09-Oct-09	Swaps							
110	Hedge : 30	Trade Date	23-Nov-09	Swaps							
111	Hedge : 31	Trade Date	30-Nov-09	Swaps							
112	Hedge : 32	Trade Date	14-Dec-09	Swaps							
113	Hedge : 33	Trade Date	30-Dec-09	Swaps							
114	Hedge : 34	Trade Date	15-Jan-10	Swaps							
115	Hedge : 35	Trade Date	29-Jan-10	Swaps							
116	Hedge : 36	Trade Date	12-Feb-10	Swaps							
117	Hedge : 37	Trade Date	26-Feb-10	Swaps							
118											
119											

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

Line	For Month of:			Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct Off Peak Strip Average
120											May- Oct
121	Hedge Dollars										
122	Hedge : 1	Trade Date	06-Jun-08	Swaps							
123	Hedge : 2	Trade Date	16-May-08	Swaps							
124	Hedge : 3	Trade Date	20-Jun-08	Swaps							
125	Hedge : 4	Trade Date	25-Jul-08	Swaps							
126	Hedge : 5	Trade Date	08-Aug-08	Swaps							
127	Hedge : 6	Trade Date	25-Aug-08	Swaps							
128	Hedge : 7	Trade Date	05-Sep-08	Swaps							
129	Hedge : 8	Trade Date	07-Nov-08	Swaps							
130	Hedge : 9	Trade Date	21-Nov-08	Swaps							
131	Hedge : 10	Trade Date	29-Jan-09	Swaps							
132	Hedge : 11	Trade Date	23-Mar-09	Swaps							
133	Hedge : 12	Trade Date	26-Mar-09	Swaps							
134	Hedge : 13	Trade Date	09-Apr-09	Swaps							
135	Hedge : 14	Trade Date	30-Apr-09	Swaps							
136	Hedge : 15	Trade Date	12-Jun-09	Swaps							
137	Hedge : 16	Trade Date	25-Jun-09	Swaps							
138	Hedge : 17	Trade Date	10-Jul-09	Swaps							
139	Hedge : 18	Trade Date	21-Aug-09	Swaps							
140	Hedge : 19	Trade Date	15-May-09	Swaps							
141	Hedge : 20	Trade Date	29-May-09	Swaps							
142	Hedge : 21	Trade Date	12-Jun-09	Swaps							
143	Hedge : 22	Trade Date	25-Jun-09	Swaps							
144	Hedge : 23	Trade Date	10-Jul-09	Swaps							
145	Hedge : 24	Trade Date	27-Jul-09	Swaps							
146	Hedge : 25	Trade Date	07-Aug-09	Swaps							
147	Hedge : 26	Trade Date	21-Aug-09	Swaps							
148	Hedge : 27	Trade Date	11-Sep-09	Swaps							
149	Hedge : 28	Trade Date	25-Sep-09	Swaps							
150	Hedge : 29	Trade Date	09-Oct-09	Swaps							
151	Hedge : 30	Trade Date	23-Nov-09	Swaps							
152	Hedge : 31	Trade Date	30-Nov-09	Swaps							
153	Hedge : 32	Trade Date	14-Dec-09	Swaps							
154	Hedge : 33	Trade Date	30-Dec-09	Swaps							
155	Hedge : 34	Trade Date	15-Jan-10	Swaps							
156	Hedge : 35	Trade Date	29-Jan-10	Swaps							
157	Hedge : 36	Trade Date	12-Feb-10	Swaps							
158	Hedge : 37	Trade Date	26-Feb-10	Swaps							
159											
160	Subtotal Hedge Dollars				$1,361,712	$0	$0	$0	$0	$1,269,985	$2,631,697
161											
162	Weighted Average Hedged Cost per Unit				$7.1669	$0.0000	$0.0000	$0.0000	$0.0000	$6.0475	$6.5792
163											
164											
165											

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Line		Reference		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	May - Oct Off Peak Strip Average
1	**ENERGY NORTH NATURAL GAS, INC.**									
2	**d/b/a National Grid NH**									
3	**Off Peak 2010 Summer Cost of Gas Filing**									
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**									
5										
6	For Month of:									
166										
167	NYMEX Settlement - 15 Day Average									
168		Days	Date							
169										
170		15	18-Feb	5.2260	5.2980	5.3740	5.4290	5.4590	5.5500	
171		14	19-Feb	5.1210	5.1900	5.2620	5.3160	5.3460	5.4310	
172			20-Feb							
173			21-Feb							
174		13	22-Feb	4.9770	5.0520	5.1270	5.1830	5.2150	5.3050	
175		12	23-Feb	4.8750	4.9520	5.0320	5.0910	5.1230	5.2170	
176		11	24-Feb	4.9270	5.0050	5.0860	5.1460	5.1810	5.2760	
177		10	25-Feb	4.8310	4.9100	4.9920	5.0550	5.0930	5.1950	
178		9	26-Feb	4.8790	4.9590	5.0430	5.1070	5.1450	5.2500	
179			27-Feb							
180			28-Feb							
181		8	01-Mar	4.7460	4.8270	4.9120	4.9760	5.0160	5.1220	
182		7	02-Mar	4.7750	4.8500	4.9340	4.9970	5.0350	5.1400	
183		6	03-Mar	4.8210	4.8920	4.9770	5.0380	5.0750	5.1790	
184		5	04-Mar	4.6430	4.7170	4.8060	4.8670	4.9030	5.0040	
185		4	05-Mar	4.6590	4.7290	4.8200	4.8830	4.9230	5.0240	
186			06-Mar							
187			07-Mar							
188		3	08-Mar	4.5900	4.6590	4.7500	4.8140	4.8560	4.9570	
189		2	09-Mar	4.5750	4.6430	4.7350	4.7970	4.8360	4.9330	
190		1	10-Mar	4.6240	4.6960	4.7890	4.8510	4.8860	4.9810	
191										
192			15 Day Average	4.8179	4.8919	4.9759	5.0367	5.0728	5.1709	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Annual Bill Comparisons, May 09 - Oct 09 vs May 10 - Oct 10 - Residential Heating Rate R-3

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

Residential Heating (R3)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	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															
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								$14.03	$14.03	$14.03	$14.03	$14.03	$14.03	$84.18	$168.36
Headblock	$0.2467								$4.93	$4.93	$4.93	$4.93	$4.93	$4.93	$29.60	$177.62
Tailblock	$0.1859								$13.01	$6.51	$1.86	$1.86	$4.09	$9.48	$36.81	$98.53
HB Threshold	20															
Total Base Rate Amount		$40.37	$48.00	$54.87	$55.06	$50.97	$44.65	$293.92	$31.98	$25.47	$20.82	$20.82	$23.05	$28.44	$150.59	$444.51
CGA Rate - (Seasonal)		$0.9663	$0.9239	$0.8975	$0.9155	$1.0230	$1.0230	$0.9535	$0.7784	$0.7784	$0.7784	$0.7784	$0.7784	$0.7784	$0.7784	$0.9090
CGA amount		$105.33	$138.58	$167.83	$172.12	$169.82	$135.04	$888.70	$70.06	$42.81	$23.35	$23.35	$32.69	$55.27	$247.53	$1,136.23
LDAC		$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404
LDAC amount		$4.40	$6.06	$7.55	$7.59	$6.71	$5.33	$37.65	$3.64	$2.22	$1.21	$1.21	$1.70	$2.87	$12.85	$50.50
Total Bill		$150.10	$192.63	$230.25	$234.77	$227.49	$185.02	$1,220.27	$105.67	$70.50	$45.39	$45.39	$57.44	$86.58	$410.97	$1,631.24

Residential Heating (R3)

			Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	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
Winter:	08/24/2008	07/01/2009															
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	$13.95								$11.46	$11.46	$13.95	$14.03	$14.03	$14.03	$78.96	$147.72
Headblock	$0.3356	$0.2453								$6.71	$6.71	$4.91	$4.93	$4.93	$4.93	$33.13	$234.49
Tailblock	$0.1950	$0.1849								$13.65	$6.83	$1.85	$1.86	$4.09	$9.48	$37.75	$102.49
HB Threshold	20	20															
Total Base Rate Amount			$46.78	$54.77	$61.99	$62.18	$57.89	$51.26	$334.86	$31.82	$25.00	$20.71	$20.82	$23.05	$28.44	$149.85	$484.71
CGA Rate - (Seasonal)			$1.1837	$1.1380	$1.1201	$1.0988	$1.0482	$0.9470	$1.0888	$0.6722	$0.6324	$0.6200	$0.6077	$0.5866	$0.5272	$0.6106	$0.9672
CGA amount			$129.02	$170.70	$209.46	$206.57	$174.00	$125.00	$1,014.76	$60.50	$34.78	$18.60	$18.23	$24.64	$37.43	$194.18	$1,208.94
LDAC			$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260
LDAC amount			$2.83	$3.90	$4.86	$4.89	$4.32	$3.43	$24.23	$2.34	$1.43	$0.78	$0.78	$1.09	$1.85	$8.27	$32.50
Total Bill			$178.63	$229.37	$276.31	$273.64	$236.21	$179.70	$1,373.85	$94.66	$61.21	$40.09	$39.83	$48.78	$67.72	$352.29	$1,726.15

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	($28.53)	($36.74)	($46.05)	($38.87)	($8.71)	$5.32	($153.58)	$11.01	$9.30	$5.30	$5.55	$8.66	$18.86	$58.68	($94.91)
% Change	-15.97%	-16.02%	-16.67%	-14.21%	-3.69%	2.96%	-11.18%	11.63%	15.19%	13.23%	13.94%	17.75%	27.85%	16.66%	-5.50%
Base Rate	($6.40)	($6.78)	($7.11)	($7.12)	($6.92)	($6.61)	($40.94)	$0.15	$0.47	$0.12	$0.00	$0.00	$0.00	$0.75	($40.19)
% Change	-13.69%	-12.37%	-11.47%	-11.45%	-11.95%	-12.90%	-12.23%	0.49%	1.89%	0.57%	0.00%	0.00%	0.00%	0.50%	-8.29%
CGA & LDAC	($22.13)	($29.96)	($38.94)	($31.75)	($1.79)	$11.93	($112.64)	$10.85	$8.82	$5.18	$5.55	$8.66	$18.86	$57.93	($54.71)
% Change	-17.15%	-17.55%	-18.59%	-15.37%	-1.03%	9.55%	-11.10%	17.94%	25.36%	27.87%	30.46%	35.15%	50.38%	29.83%	-4.53%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Annual Bill Comparisons, May 09 - Oct 09 vs May 10 - Oct 10 - Commercial Rate G-41

November 1, 2009 - April 30, 2010 | May 1, 2010 - October 31, 2010
Commercial Rate (G-41)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	08/01/2009															
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								$35.08	$35.08	$35.08	$35.08	$35.08	$35.08	$210.48	$420.96
Headblock	$0.2974								$5.95	$5.95	$5.95	$5.95	$5.95	$5.95	$35.69	$214.13
Tailblock	$0.1934								$18.76	$11.80	$10.06	$10.06	$13.34	$23.59	$87.61	$247.55
HB Threshold	20															
Total Base Rate Amount		$82.81	$97.50	$103.11	$96.15	$90.74	$78.55	$548.86	$59.79	$52.83	$51.08	$51.08	$54.37	$64.62	$333.78	$882.64
CGA Rate - (Seasonal)		$0.9665	$0.9241	$0.8977	$0.9157	$1.0232	$1.0232	$0.9509	$0.7788	$0.7788	$0.7788	$0.7788	$0.7788	$0.7788	$0.7788	$0.9016
CGA amount		$186.53	$248.57	$267.50	$239.92	$239.43	$174.97	$1,356.92	$91.12	$63.08	$56.07	$56.07	$69.31	$110.59	$446.25	$1,803.17
LDAC		$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0194	$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	$2.27	$1.57	$1.40	$1.40	$1.73	$2.75	$11.12	$38.80
Total Bill		$273.08	$351.30	$376.40	$341.15	$334.70	$256.84	$1,933.47	$153.18	$117.48	$108.56	$108.56	$125.41	$177.97	$791.15	$2,724.61

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	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	08/24/2008	07/01/2009															
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	$34.88								$28.58	$28.58	$34.88	$35.08	$35.08	$35.08	$197.28	$368.76
Headblock	$0.3732	$0.2956								$7.46	$7.46	$5.91	$5.95	$5.95	$5.95	$38.68	$262.60
Tailblock	$0.2427	$0.1923								$23.54	$14.80	$10.00	$10.06	$13.34	$23.59	$95.34	$296.06
HB Threshold	20	20															
Total Base Rate Amount			$88.47	$106.92	$113.95	$105.22	$98.42	$83.13	$596.11	$59.59	$50.85	$50.79	$51.08	$54.37	$64.62	$331.31	$927.42
CGA Rate - (Seasonal)			$1.1839	$1.1382	$1.1203	$1.0990	$1.0484	$0.9471	$1.0958	$0.6727	$0.6329	$0.6205	$0.6082	$0.5871	$0.5277	$0.6032	$0.9547
CGA amount			$228.49	$306.18	$333.85	$287.94	$245.33	$161.95	$1,563.74	$78.71	$51.26	$44.68	$43.79	$52.25	$74.93	$345.62	$1,909.36
LDAC			$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	0.0278	$0.0278	$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	$3.25	$2.25	$2.00	$2.00	$2.47	$3.95	$15.93	$55.60
Total Bill			$322.33	$420.57	$456.09	$400.44	$350.25	$249.84	$2,199.52	$141.54	$104.37	$97.47	$96.88	$109.10	$143.50	$692.86	$2,892.38

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	($49.24)	($69.27)	($79.69)	($59.29)	($15.55)	$7.00	($266.05)	$11.63	$13.11	$11.09	$11.68	$16.31	$34.46	$98.29	($167.76)
% Change	-15.28%	-16.47%	-17.47%	-14.81%	-4.44%	2.80%	-12.10%	8.22%	12.57%	11.37%	12.05%	14.95%	24.02%	14.19%	-5.80%
Base Rate	($5.66)	($9.41)	($10.84)	($9.07)	($7.69)	($4.58)	($47.25)	$0.20	$1.98	$0.29	$0.00	$0.00	$0.00	$2.47	($44.78)
% Change	-6.40%	-8.80%	-9.51%	-8.62%	-7.81%	-5.51%	-7.93%	0.34%	3.89%	0.58%	0.00%	0.00%	0.00%	0.75%	-4.83%
CGA & LDAC	($43.58)	($59.86)	($68.85)	($50.22)	($7.86)	$11.58	($218.80)	$11.43	$11.14	$10.79	$11.68	$16.31	$34.46	$95.82	($122.99)
% Change	-19.07%	-19.55%	-20.62%	-17.44%	-3.21%	7.15%	-13.99%	14.52%	21.73%	24.16%	26.67%	31.22%	45.99%	27.72%	-6.44%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Annual Bill Comparisons, May 09 - Oct 09 vs May 10 - Oct 10 - Commercial Rate G-42

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

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	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																
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									$100.24	$100.24	$100.24	$100.24	$100.24	$100.24	$601.44	$1,202.88
Headblock	$0.2642									$105.68	$105.68	$105.68	$56.27	$96.17	$105.68	$575.16	$2,160.36
Tailblock	$0.1745									$149.72	$52.52	$2.44	$0.00	$0.00	$52.18	$256.86	$2,241.63
HB Threshold	400																
Total Base Rate Amount			$460.94	$639.80	$759.68	$905.91	$783.59	$621.48	$4,171.40	$355.64	$258.44	$208.36	$156.51	$196.41	$258.10	$1,433.47	$5,604.87
CGA Rate - (Seasonal)			$0.9665	$0.9241	$0.8977	$0.9157	$1.0232	$1.0232	$0.9544	$0.7788	$0.7788	$0.7788	$0.7788	$0.7788	$0.7788	$0.7788	$0.9240
CGA amount			$1,500.97	$2,382.23	$2,930.87	$3,757.15	$3,480.91	$2,530.36	$16,582.50	$979.73	$545.94	$322.42	$165.88	$283.48	$544.38	$2,841.84	$19,424.34
LDAC			$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194
LDAC amount			$30.13	$50.01	$63.34	$79.60	$66.00	$47.98	$337.06	$24.41	$13.60	$8.03	$4.13	$7.06	$13.56	$70.79	$407.85
Total Bill			$1,992.04	$3,072.05	$3,753.89	$4,742.66	$4,330.50	$3,199.82	$21,090.96	$1,359.78	$817.98	$538.82	$326.53	$486.95	$816.04	$4,346.10	$25,437.06

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-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
	08/24/2008	07/01/2009															
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	$99.66								$80.44	$80.44	$99.66	$100.24	$100.24	$100.24	$561.26	$1,043.90
Headblock	$0.3095	$0.2627								$123.80	$123.80	$105.08	$56.27	$96.17	$105.68	$610.80	$2,467.80
Tailblock	$0.2044	$0.1735								$175.38	$61.52	$2.43	$0.00	$0.00	$52.18	$291.50	$2,616.35
HB Threshold	400	400															
Total Base Rate Amount			$502.97	$712.48	$852.91	$1,024.19	$880.91	$691.02	$4,664.49	$379.62	$265.76	$207.17	$156.51	$196.41	$258.10	$1,463.57	$6,128.05
CGA Rate - (Seasonal)			$1.1839	$1.1382	$1.1203	$1.0990	$1.0484	$0.9471	$1.0849	$0.6727	$0.6329	$0.6205	$0.6082	$0.5871	$0.5277	$0.6191	$1.0040
CGA amount			$1,838.60	$2,934.28	$3,657.78	$4,509.20	$3,566.66	$2,342.18	$18,848.69	$846.26	$443.66	$256.89	$129.55	$213.70	$368.86	$2,258.92	$21,107.61
LDAC			$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278
LDAC amount			$43.17	$71.67	$90.77	$114.06	$94.58	$68.75	$483.00	$34.97	$19.49	$11.51	$5.92	$10.12	$19.43	$101.44	$584.44
Total Bill			$2,384.74	$3,718.43	$4,601.45	$5,647.45	$4,542.14	$3,101.95	$23,996.17	$1,260.84	$728.92	$475.57	$291.98	$420.23	$646.39	$3,823.93	$27,820.10

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	($392.70)	($646.38)	($847.56)	($904.79)	($211.64)	$97.87	($2,905.21)	$98.93	$89.07	$63.25	$34.55	$66.72	$169.65	$522.17	($2,383.04)
% Change	-16.47%	-17.38%	-18.42%	-16.02%	-4.66%	3.16%	-12.11%	7.85%	12.22%	13.30%	11.83%	15.88%	26.25%	13.66%	-8.57%
Base Rate	($42.03)	($72.68)	($93.22)	($118.28)	($97.32)	($69.54)	($493.08)	($23.97)	($7.32)	$1.19	$0.00	$0.00	$0.00	($30.10)	($523.18)
% Change	-8.36%	-10.20%	-10.93%	-11.55%	-11.05%	-10.06%	-10.57%	-6.32%	-2.75%	0.58%	0.00%	0.00%	0.00%	-2.06%	-8.54%
CGA & LDAC	($350.67)	($573.70)	($754.34)	($786.51)	($114.32)	$167.41	($2,412.13)	$122.91	$96.39	$62.06	$34.55	$66.72	$169.65	$552.27	($1,859.86)
% Change	-19.07%	-19.55%	-20.62%	-17.44%	-3.21%	7.15%	-12.80%	14.52%	21.73%	24.16%	26.67%	31.22%	45.99%	24.45%	-8.81%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Annual Bill Comparisons, May 09 - Oct 09 vs May 10 - Oct 10 - Commercial Rate G-52

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

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	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															
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								$100.24	$100.24	$100.24	$100.24	$100.24	$100.24	$601.44	$1,202.88
Headblock	$0.1106								$110.60	$110.60	$110.60	$110.60	$110.60	$110.60	$663.60	$1,566.60
Tailblock	$0.0637								$32.49	$23.82	$15.73	$12.10	$13.38	$20.64	$118.16	$795.49
HB Threshold	1,000															
Total Base Rate Amount		$324.46	$361.62	$386.53	$386.84	$382.55	$339.77	$2,181.77	$243.33	$234.66	$226.57	$222.94	$224.22	$231.48	$1,383.20	$3,564.97
CGA Rate - (Seasonal)		$0.9658	$0.9234	$0.8970	$0.9150	$1.0225	$1.0225	$0.9554	$0.7778	$0.7778	$0.7778	$0.7778	$0.7778	$0.7778	$0.7778	$0.8873
CGA amount		$1,663.11	$1,926.13	$2,089.92	$2,134.71	$2,342.54	$1,914.11	$12,070.53	$1,174.48	$1,068.70	$969.92	$925.58	$941.14	$1,029.81	$6,109.62	$18,180.15
LDAC		$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194
LDAC amount		$33.41	$40.47	$45.20	$45.26	$44.45	$36.32	$245.10	$29.29	$26.66	$24.19	$23.09	$23.47	$25.69	$152.39	$397.49
Total Bill		$2,020.97	$2,328.22	$2,521.66	$2,566.81	$2,769.53	$2,290.20	$14,497.40	$1,447.10	$1,330.02	$1,220.68	$1,171.61	$1,188.83	$1,286.97	$7,645.21	$22,142.61

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-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:	08/24/2008	07/01/2009															
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	$99.66								$80.36	$80.36	$99.66	$100.24	$100.24	$100.24	$561.10	$1,043.26
Headblock	$0.1453	$0.1100								$145.30	$145.30	$110.00	$110.60	$110.60	$110.60	$732.40	$1,918.00
Tailblock	$0.0836	$0.0633								$42.64	$31.27	$15.64	$12.10	$13.38	$20.64	$135.66	$1,025.28
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	$268.30	$256.93	$225.30	$222.94	$224.22	$231.48	$1,429.16	$3,986.54
CGA Rate - (Seasonal)			$1.1826	$1.1369	$1.1190	$1.0977	$1.0471	$0.9461	$1.0880	$0.6707	$0.6309	$0.6185	$0.6062	$0.5851	$0.5257	$0.6081	$0.9040
CGA amount			$2,036.44	$2,371.57	$2,607.27	$2,560.93	$2,398.91	$1,771.10	$13,746.22	$1,012.76	$866.86	$771.27	$721.38	$707.97	$696.03	$4,776.26	$18,522.48
LDAC			$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278
LDAC amount			$47.87	$57.99	$64.77	$64.86	$63.69	$52.04	$351.23	$41.98	$38.20	$34.67	$33.08	$33.64	$36.81	$218.37	$569.59
Total Bill			$2,459.09	$2,853.16	$3,128.36	$3,082.51	$2,913.68	$2,218.04	$16,654.82	$1,323.03	$1,161.98	$1,031.23	$977.40	$965.83	$964.31	$6,423.78	$23,078.61

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	($438.12)	($524.93)	($606.70)	($515.69)	($144.14)	$72.16	($2,157.43)	$124.07	$168.04	$189.45	$194.21	$223.00	$322.66	$1,221.43	($936.00)
% Change	-17.82%	-18.40%	-19.39%	-16.73%	-4.95%	3.25%	-12.95%	9.38%	14.46%	18.37%	19.87%	23.09%	33.46%	19.01%	-4.06%
Base Rate	($50.32)	($61.97)	($69.78)	($69.88)	($68.53)	($55.12)	($375.61)	($24.97)	($22.26)	$1.28	$0.00	$0.00	$0.00	($45.95)	($421.56)
% Change	-13.43%	-14.63%	-15.29%	-15.30%	-15.19%	-13.96%	-14.69%	-9.31%	-8.66%	0.57%	0.00%	0.00%	0.00%	-3.22%	-10.57%
CGA & LDAC	($387.79)	($462.96)	($536.92)	($445.82)	($75.61)	$127.29	($1,781.82)	$149.04	$190.30	$188.17	$194.21	$223.00	$322.66	$1,267.38	($514.44)
% Change	-19.04%	-19.52%	-20.59%	-17.41%	-3.15%	7.19%	-12.96%	14.72%	21.95%	24.40%	26.92%	31.50%	46.36%	26.53%	-2.78%

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

	Summer 2009	Summer 2010
Customer Charge	$11.46	$14.03
First 20 Therms	$0.3356	$0.2467
Excess 20 Therms	$0.1950	$0.1859
LDAC	$0.0260	$0.0404
CGA	$0.6106	$0.7784
Total Adjust	$0.6366	$0.8188

		Summer 2009 CGA @	Summer 2010 CGA @	Total $ Impact	Total % Impact	Base Rate $ Impact	Base Rate % Impact	CGA $ Impact	CGA % Impact	LDAC $ Impact	LDAC % Impact
		$0.6366	$0.8188	$0.18	29%						
Cooking alone	5	$16.32	$19.36	$3.04	19%	$2.13	13%	$0.84	4%	$0.07	0%
	10	$21.18	$24.68	$3.50	17%	$1.68	8%	$1.68	7%	$0.14	1%
	20	$30.90	$35.34	$4.44	14%	$0.79	3%	$3.36	9%	$0.29	1%
Water Heating alone	30	$39.22	$45.39	$6.17	16%	$0.70	2%	$5.03	11%	$0.43	1%
	45	$51.70	$60.46	$8.76	17%	$0.56	1%	$7.55	12%	$0.65	1%
	50	$55.85	$65.48	$9.63	17%	$0.52	1%	$8.39	13%	$0.72	1%
Heating Alone	80	$76.64	$90.60	$13.95	18%	$0.29	0%	$12.58	14%	$1.08	1%
	125	$124.88	$148.87	$23.99	19%	-$0.24	0%	$22.31	15%	$1.91	2%
	150	$139.02	$165.95	$26.93	19%	-$0.39	0%	$25.17	15%	$2.16	2%
	200	$180.60	$216.19	$35.59	20%	-$0.85	0%	$33.55	16%	$2.88	2%

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

	SUMMER SALES ACTUAL RESULTS (6 months actual)			SUMMER 2010 (6 months Proposed)		
Therm Sales	19,796,271			21,428,146		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 3,004,243	$ 0.1518		$ 3,253,976	$ 0.1519
Purchased Gas	19,707,760	7,806,853	0.3944	22,853,693	12,301,578	0.5741
Storage Gas	326,250	227,829	0.0115	0	0	0.0000
Produced Gas	128,080	95,190	0.0048	147,017	77,045	0.0036
Hedging (Gain)/Loss		2,715,164	0.1372		630,394	0.0294
Total Volumes and Cost	20,162,090	$ 13,849,279	$ 0.6996	23,000,711	$ 16,262,993	$ 0.7590
Prior Period Balance		$ (1,704,061)	$ (0.0861)		38,753	$ 0.0018
Interest		(11,716)	(0.0006)		9,800	0.0005
Prior Period Adjustment		-	-		-	-
Broker Revenues		-	-		-	-
Refunds from Suppliers		-	-		-	-
Fuel Financing		-	-		-	-
Transportation CGA Revenues		-	-		-	-
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		-	-		-	-
Hedging Costs		-	-		-	-
Misc Overhead		12,609	0.0006		5,260	0.0002
Occupant Disallowance/Credits		(31,121)				
Production & Storage		-	-			
FPO Admin Costs		-	-		-	-
Indirect Gas Costs		119,096	0.0060		362,447	0.0169
Total Adjusted Cost		$ 12,234,088	**$ 0.6180**		$ 16,679,253	**$ 0.7784**

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ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

2010 Summer Cost of Gas Filing

Capacity Assignment Calculations 2009-2010

Derivation of Class Assignments and Weightings

3

5

					Column A	Column B	Column C	Column D	Column E	Column F
					5	5	0 5			5 3
	3				3	3				3 0
3					3 5	5 3 0			0	500
	5					5	0		5	
5					33 5 3	35 553				33 5
	5					3	3 0		3	3 0
	3					05	3		3	5
	53				05	0	3		5	3
	5					30	0		0	5 0
0										
					35	3 0	00 0		0 0	33 55
3					5	00	**47.294%**		3	3
						5	**45.791%**		3	
5					50		**6.915%**			
					35	3 0	00 0		0 0	33 55
									3	
0										
									5	0
3										
									5 3	3 3
5									3 0	0 5
									100.0%	**100.0%**
					5 5	5	0 03			
30					3 0 00	5	0 0 0			
3										
3					5 33 3					
33					3 0					
3					3	0	55			
35					0 3	3 00	3			
3										
3										
3					0	0 0	0 03			
3					35		0 0			
0					3 0 00	5	0 0 0			
					3	0	55			
					0 3	3 00	3			
3										
5										
		3	3	**47.294%**	5	5	0 03			
		3	3	**47.294%**	5		0 0			
		0	3	**47.294%**	0	3	0 0 0			
			3	**47.294%**	3 0	3	55			
50				**47.294%**	0	00	3			

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

2010 Summer Cost of Gas Filing

Capacity Assignment Calculations 2009-2010

Derivation of Class Assignments and Weightings

5							
5							**Ratios for COG**
5							
54		4		5	5 5	0 0	
55		4		54 5	545	0 0	
5	40	4		540	4	00 0	
5	4	4		55 00		55	
5			**52.706%**	4 54	5	4	**1.0000**
5							
0							
	54	4				0	
	55	4		5	0	0 0	
4	5	4		0 50		00 0	
5	5	4		5	0	5	
			45.9103%	4	5 4	4	**1.0008**
			5				5
0	54			50 500	4	0	
	55				50	0	
	5	4		0	5	0 0	
	5	5		5	4 5	4	
4			**6.7955%**	0		4	**0.9944**
5							4 5
				0 0	0 0	0 0	
0				00 0	00 0	00 0	
				4	4	4	
4							
5					**LLF C&I**	**HLF C&I**	
				05	**36.41%**	**49.08%**	
				55	**20.07%**	**16.07%**	
				4 40	**43.52%**	**34.85%**	
0				00 00	**100.00%**	**100.00%**	
4							
5				4	4		00 00
				4	4 0	5	00 00
				4	4 0	5	00 00

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **2010 Summer Cost of Gas Filing**
4 **Correction Factor Calculation**
5
6
7
8 Data Source: Schedule 10B

Ln		May	June	July	August	September	October	Total Sales
10								
11	G-41	820,752	353,054	221,383	210,194	231,203	379,997	2,216,583
12	G-42	1,378,730	737,164	443,392	423,194	488,060	751,086	4,221,625
13	G-43	211,286	140,704	83,249	74,640	84,821	106,015	700,715
14	High Winter Use	2,410,767	1,230,922	748,024	708,028	804,084	1,237,098	7,138,923
15								
16	G-51	258,290	209,515	167,167	169,207	177,878	200,622	1,182,680
17	G-52	388,329	343,614	292,219	288,028	295,369	322,051	1,929,610
18	G-53	47,735	58,704	40,283	38,321	39,317	41,177	265,537
19	G-54	10,073	8,545	9,095	7,763	9,788	9,381	54,645
21	Low Winter Use	704,428	620,378	508,763	503,320	522,353	573,231	3,432,472
22								
23	Gross Total	3,115,195	1,851,300	1,256,786	1,211,348	1,326,436	1,810,330	10,571,396

24
25

Ln			
26	Total Sales	10,571,396	
27	Low Winter Use	3,432,472	
28	Summer Ratio for Low Winter Use	**0.99440**	Schedule 10A p 2, ln 74
29	High Winter Use	7,138,923	
30	Summer Ratio for High Winter Use	**1.00080**	Schedule 10A p 2, ln 66
31			
32	Correction Factor =	Total Sales / (Low Summer Ratio x Low Summer Sales)+(High Summer Ratio x High Summer Sale	
33	Correction Factor =	**100.1280%**	

34
35
36 **Allocation Calculation for Miscellaneous Overhead**
37

Ln				
38	Projected Summer Sales Volume	(5/1/10 - 10/31/10)	21,908,432	Sch.10B, ln 24
39	Projected Annual Sales Volume	(11/1/09 - 10/31/10)	105,710,244	Sch.10B, ln 24
40	Percentage of Summer Sales to Annual Sales		20.72%	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **2010 Summer Cost of Gas Filing**
5
6 **Dry Therms**

Line		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Subtotal PK 09-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Subtotal OP 10	Total
7	**Firm Sales**															
8																
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**

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Normal and Design Year Volumes

Schedule 11A
Page 1 of 1

Volumes (Therms) **Normal Year**

For the Months of November 09 -April 10

	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Off Peak May - Oct
Pipeline Gas:							
Dawn Supply	-	-	-	-	-	-	0
Niagara Supply	-	-	-	-	-	-	0
TGP Supply (Direct)	2,882,508	3,899,955	3,836,489	831,390	831,390	1,313,940	13,595,672
Dracut Supply 1 - Baseload	-	-	-	-	-	-	0
Dracut Supply 2 - Swing	1,940,115	-	-	2,995,755	3,390,725	5,722,244	14,048,838
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	79,674	23,970	24,769	24,769	23,970	24,769	201,922
Propane Truck	-	-	-	-	-	-	0
PNGTS	38,588	27,250	26,073	26,855	30,783	47,974	197,523
Granite Ridge	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	4,940,885	3,951,176	3,887,331	3,878,769	4,276,868	7,108,927	28,043,955
Storage Gas:							
TGP Storage	-	-	-	-	-	-	0
Produced Gas:							
LNG Vapor	24,769	23,970	24,769	24,769	23,970	24,769	147,017
Propane	-	-	-	-	-	-	0
Subtotal Produced Gas	24,769	23,970	24,769	24,769	23,970	24,769	147,017
Less - Gas Refills:							
LNG Truck	(79,674)	(23,970)	(24,769)	(24,769)	(23,970)	(24,769)	(201,922)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(4,988,340)
Subtotal Refills	(911,064)	(855,360)	(856,159)	(856,159)	(855,360)	(856,159)	(5,190,262)
Total Sendout Volumes	4,054,590	3,119,786	3,055,941	3,047,379	3,445,478	6,277,537	23,000,711

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
42 **Normal and Design Year Volumes**

43
44
45 **Volumes (Therms)** **Design Year**
46
47 **For the Months of November 09 -April 10**
48

		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Off Peak May - Oct
51	Pipeline Gas:							
52	Dawn Supply	-	-	-	-	-	-	-
53	Niagara Supply	-	-	-	-	-	-	-
54	TGP Supply (Direct)	1,713,502	3,926,768	3,836,489	831,390	831,390	1,652,567	12,792,106
55	Dracut Supply 1 - Baseload	-	-	-	-	-	-	-
56	Dracut Supply 2 - Swing	3,323,701	-	-	2,998,581	3,492,712	5,900,658	15,715,651
57	City Gate Delivered Supply	-	-	-	-	-	-	0
58	LNG Truck	79,674	23,970	24,769	24,769	23,970	24,769	201,922
59	Propane Truck	-	-	-	-	-	-	0
60	PNGTS	38,588	27,250	26,073	26,855	30,783	47,974	197,523
61	Granite Ridge	-	-	-	-	-	-	-
62	Other Purchased Resources	-	-	-	-	-	-	
63	Subtotal Pipeline Volumes	5,155,464	3,977,989	3,887,331	3,881,595	4,378,855	7,625,969	28,907,202
64								
65	Storage Gas:							
66	TGP Storage	-	-	-	-	-	-	0
67								
68	Produced Gas:							
69	LNG Vapor	24,769	23,970	24,769	24,769	23,970	24,769	147,017
70	Propane	-	-	-	-	-	-	-
71	Subtotal Produced Gas	24,769	23,970	24,769	24,769	23,970	24,769	147,017
72								
73	Less - Gas Refills:							
74	LNG Truck	(79,674)	(23,970)	(24,769)	(24,769)	(23,970)	(24,769)	(201,922)
75	Propane	-	-	-	-	-	-	-
76	TGP Storage Refill	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(831,390)	(4,988,340)
77	Subtotal Refills	(911,064)	(855,360)	(856,159)	(856,159)	(855,360)	(856,159)	(5,190,262)
78								
79	Total Sendout Volumes	4,269,170	3,146,599	3,055,941	3,050,205	3,547,465	6,794,579	23,863,958

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Capacity Utilization**
5 **Volumes (Therms)**
6

Line		Off-Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Off-Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
11	**Pipeline Gas:**								
12	Dawn Supply	-	4,000	7,240,000	0%	-	4,000	7,240,000	0%
13	Niagara Supply	-	3,122	5,650,820	0%	-	3,122	5,650,820	0%
14	TGP Supply (Direct)	13,595,672	21,596	39,088,760	35%	12,792,106	21,596	39,088,760	33%
15	Dracut Supply 1 & 2	14,048,838	50,000	90,500,000	16%	15,715,651	50,000	90,500,000	17%
18	LNG Truck	201,922	-	-	-	201,922	-	-	-
19	Propane Truck	-	-	-	-	-	-	-	-
20	PNGTS	197,523	1,000	1,810,000	11%	197,523	1,000	1,810,000	11%
21	Granite Ridge	-	-	-	-	-	-	-	0%
22	Other Purchased Resources	-	-	-	-	-	-	-	0%
23									
24	Subtotal Pipeline Volumes	28,043,955				28,907,202			
25									
26	**Storage Gas:**								
27	TGP Storage	0		25,801,310	0%	-		25,801,310	0%
28									
29	**Produced Gas:**								
30	LNG Vapor	147,017				147,017			
31	Propane	-				-			
32									
33	Subtotal Produced Gas	147,017				147,017			
34									
35	**Less - Gas Refills:**								
36	LNG Truck	(201,922)				(201,922)			
37	Propane	-				-			
38	TGP Storage Refill	(4,988,340)				(4,988,340)			
39									
40	Subtotal Refills	(5,190,262)				(5,190,262)			
41									
42	Total Sendout Volumes	23,000,711				23,863,958			

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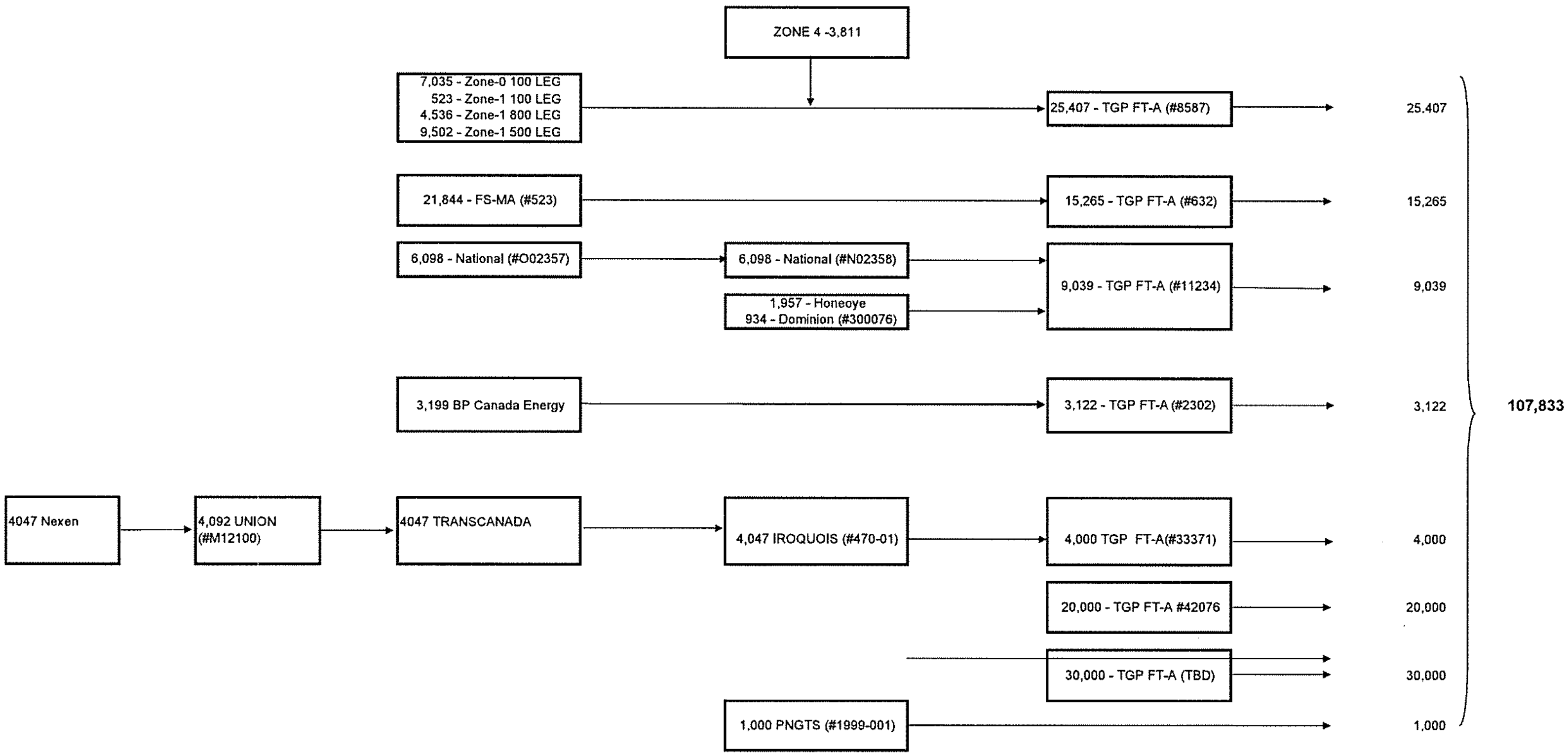
ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer 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	09/30/10	N/a	Mutually agreed upon.
BP Gas & Power Canada, Ltd	-	-	Supply	3,199	1,167,635	03/31/2012	N/a	Terminates
TBD No Supply for April through October 2010	-	-	Supply	4,047	611,097	Peak Only	N/a	Terminates
Distrigas of Massachusetts Corp.	FLS	FLS160	Liquid Refill	Up to 15 trucks	1,000,000 KeySpan Total	10/31/2010	-	Terminates
Repsol Energy North America Corporation	-	-	Supply	May 2010 = 21,000 Oct 2010 = 16,000	7,607,500	10/31/2010	-	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	03/31/2016	03/31/2009	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	04/01/2011	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	03/31/2011	03/31/2010	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	03/31/2011	03/31/2010	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/01/2017	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	10/31/2015	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2015	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2015	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2015	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2015	10/31/2009	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	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	10/31/2015	10/31/2009	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2017	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.

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Storage Inventory**

6 **Underground Storage Gas**

Line	Description	Reference	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		826,873	2,305,808	2,175,636	1,920,272	1,798,641	1,798,641	1,798,641	1,881,780	1,964,919	2,048,058	2,131,197	2,214,336	2,297,475
11	Injections (MMBtu)	Sch 11A ln 37 /10	1,478,966	(5,972)	3,509	32,903	-	-	83,139	83,139	83,139	83,139	83,139	83,139	2,008,240
13	Subtotal		2,305,839	2,299,836	2,179,145	1,953,175	1,798,641	1,798,641	1,881,780	1,964,919	2,048,058	2,131,197	2,214,336	2,297,475	
15	Sempra Sale														
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(31)	(124,200)	(258,873)	(154,534)	-	-	-	-	-	-	-	-	(537,638)
19	Ending Balance (MMBTu)		2,305,808	2,175,636	1,920,272	1,798,641	1,798,641	1,798,641	1,881,780	1,964,919	2,048,058	2,131,197	2,214,336	2,297,475	3,768,077
22	Beginning Balance		$ 5,174,356	$ 14,683,989	$ 13,855,020	$ 12,230,397	$ 11,438,722	$ 11,438,722	$ 11,438,722	$ 11,879,915	$ 12,327,685	$ 12,782,923	$ 13,243,559	$ 13,707,406	5,174,356
24	Injections	ln 11 * ln 36	9,509,831	(38,031)	24,164	191,107	-	-	441,193	447,771	455,237	460,636	463,848	472,570	12,428,325
26	Subtotal		$ 14,684,186	$ 14,645,958	$ 13,879,184	$ 12,421,503	$ 11,438,722	$ 11,438,722	$ 11,879,915	$ 12,327,685	$ 12,782,923	$ 13,243,559	$ 13,707,406	$ 14,179,977	
28	Sempra Sale														
30	Withdrawals	ln 17 * ln 34	$ (197)	$ (790,938)	$ (1,648,787)	$ (982,782)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(3,422,704)
32	Ending Balance		$ 14,683,989	$ 13,855,020	$ 12,230,397	$ 11,438,722	$ 11,438,722	$ 11,438,722	$ 11,879,915	$ 12,327,685	$ 12,782,923	$ 13,243,559	$ 13,707,406	$ 14,179,977	14,179,977
34	Average Rate For Withdrawals	ln 18 /ln 9	$6.3683	$6.3683	$6.3691	$6.3596	$6.3596	$6.3596	$6.3131	$6.2739	$6.2415	$6.2141	$6.2141	$6.1903	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$5.1407	$5.0865	$5.7968	$6.2964	$5.9307	$5.8465	$5.3067	$5.3858	$5.4756	$5.5405	$5.5792	$5.6841	
38	For Informational Purposes		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
39	Summer Hedge Contracts - Vols Dth								71,700	71,700	71,700	71,700	71,700	71,700	430,200
40	Average Hedge Price								$5.7298	$5.7298	$5.7298	$5.7298	$5.7298	$5.7298	
41	NYMEX								$4.8179	$4.8919	$4.9759	$5.0367	$5.0728	$5.1709	
43	Hedged Volumes at Hedged Price								$ 410,830	$ 410,830	$ 410,830	$ 410,830	$ 410,830	$ 410,830	$ 2,464,977
44	Less Hedged Volumes at NYMEX								345,446	350,752	356,774	361,129	363,720	370,756	2,148,577
45	Hedge (Savings)/Loss								$ 65,384	$ 60,078	$ 54,055	$ 49,701	$ 47,110	$ 40,074	$ 316,400

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Storage Inventory**
5
57
58 **Liquid Propane Gas (LPG)**

Line			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
59															
60			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
61	Beginning Balance		137,688	137,317	137,028	135,024	133,964	133,964	133,964	133,964	133,964	133,964	133,964	133,964	137,688
62															
63	Injections	Sch 11A ln 36 /10	-	-	-	-	-	-	-	-	-	-	-	-	-
64															
65	Subtotal		137,688	137,317	137,028	135,024	133,964	133,964	133,964	133,964	133,964	133,964	133,964	133,964	
66															
67	Withdrawals	Sch 11A ln 31 /10	-	(199)	(1,994)	(1,003)	-	-	-	-	-	-	-	-	(3,196)
68															
69	Adjustment for change in temperature		(371)	(90)	(10)	(57)	-	-	-	-	-	-	-	-	(528)
70															
71	Ending Balance		137,317	137,028	135,024	133,964	133,964	133,964	133,964	133,964	133,964	133,964	133,964	133,964	133,964
72															
73															
74	Beginning Balance		2,013,191	2,007,764	2,003,538	1,974,229	1,958,726	1,958,726	1,958,726	1,958,726	1,958,726	1,958,726	1,958,726	1,958,726	2,013,191
75															
76	Injections	ln 63 * ln 86	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	Subtotal		$ 2,013,191	$ 2,007,764	$ 2,003,538	$ 1,974,229	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	
79															
80	Withdrawals	ln 69 * ln 84	(5,428)	(4,226)	(29,309)	(15,503)	-	-	-	-	-	-	-	-	(54,466)
81															
82	Ending Balance		$ 2,007,764	$ 2,003,538	$ 1,974,229	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	$ 1,958,726	1,958,726
83															
84	Average Rate For Withdrawals		$14.6214	$14.6214	$14.6214	$14.6213	$14.6213	$14.6213	$14.6213	$14.6213	$14.6213	$14.6213	$14.6213	$14.6213	
85															
86	Propane Rate for Injections	Actual or Sch. 6, ln 151 * 10	$12.7500	$12.8600	$12.9700	$13.0500	$13.1300	$13.2200	$7.4000	$7.4900	$7.5600	$7.6600	$7.7700	$7.8800	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Off Peak 2010 Summer Cost of Gas Filing**
4 **Storage Inventory**
5

Line			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
98															
99	**Liquid Natural Gas (LNG)**		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
100			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
101	Beginning Balance		11,057	9,440	10,479	11,587	10,495	12,961	10,495	15,985	15,985	15,985	15,985	15,985	11,057
103	Injections	Sch 11A ln 35 /10	554	7,229	6,478	902	4,932	-	7,967	2,397	2,477	2,477	2,397	2,477	40,287
105	Subtotal		11,611	16,669	16,957	12,489	15,427	12,961	18,462	18,382	18,462	18,462	18,382	18,462	
107	Withdrawals	Sch 11A ln 30 /10	(2,171)	(6,190)	(5,370)	(1,994)	(2,466)	(2,466)	(2,477)	(2,397)	(2,477)	(2,477)	(2,397)		(32,881)
109	Ending Balance		9,440	10,479	11,587	10,495	12,961	10,495	15,985	15,985	15,985	15,985	15,985	18,462	18,462
112	Beginning Balance		$ 59,418	49,040	53,504	58,517	62,028	74,246	60,121	85,291	84,367	83,719	83,289	83,003	59,418
114	Injections	ln 103 * ln 124	900	36,069	32,132	15,296	26,344	-	38,386	11,726	12,325	12,475	12,160	12,808	210,621
116	Subtotal		$ 60,318	$ 85,109	$ 85,637	$ 73,813	$ 88,372	$ 74,246	$ 98,507	$ 97,017	$ 96,692	$ 96,195	$ 95,449	$ 95,811	
118	Withdrawals	ln 107 * ln 122	(11,278)	(31,605)	(27,120)	(11,785)	(14,125)	(14,125)	(13,216)	(12,651)	(12,972)	(12,906)	(12,446)	-	(174,229)
120	Ending Balance		$ 49,040	$ 53,504	$ 58,517	$ 62,028	$ 74,246	$ 60,121	$ 85,291	$ 84,367	$ 83,719	$ 83,289	$ 83,003	$ 95,811	95,811
122	Average Rate For Withdrawals		$5.1949	$5.1058	$5.0502	$5.9102	$5.7285	$5.7285	$5.3356	$5.2777	$5.2372	$5.2103	$5.1924	$5.1895	
124	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$4.6111	$4.5609	$5.2180	$5.6801	$5.3419	$5.3229	$4.8179	$4.8919	$4.9759	$5.0367	$5.0728	$5.1709	

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nationalgrid

Thomas P. O'Neill

Via Overnight Delivery and E-filing

January 28, 2010

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 09-050
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
2009 Summer Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Attached is the redacted version of the 2009 summer 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 No24,963, dated April 30, 2009 in Docket DG 09-050. 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.

This reconciliation compares the actual deferred gas costs to the projections submitted in the Company's 2009 summer period cost of gas filing to the Commission on March 16, 2009. The filing shows an under recovery for the 2009 summer period of $38,753. The 2009 summer period under recovery is summarized as follows:

Summer Period Beginning Balance	($1,969,485)
Prior Period Adjustment and Interest	$265,425
Less: Cost of Gas Revenue Billed	($12,078,138)
Add: Cost of Gas Allowable	$13,820,952
Summer Period Ending Balance	$38,753

The filing consists of a four-page summary and eleven 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, prior period adjustment, interest, gas costs and gas cost revenue. The result is a net under recovery of $38,753. Page 2 of the summary compares the actual demand charges of $3,004,243 to the $3,059,785 in demand charges estimated in the filing, resulting in a decrease in demand costs of $55,542. Page 3 shows a similar comparison for commodity costs. The actual commodity costs were $10,845,036 compared to the $13,960,288 in the filing. The $3,115,252 decrease in commodity costs was caused mainly by lower sendout volumes and lower commodity prices than originally forecasted. The results show that the total actual gas costs, demand and commodity, were $3,170,794 lower than forecasted in the filing. Page 4 of the summary provides a variance analysis that explains how much of the difference between actual costs and forecasted costs is due to weather ($307,047), changes in demand resulting from lower sendout ($1,638,990) and changes in gas prices ($886,298). Page 4 also provides the net total of ($338,459) for the capacity managed credit, supplier cashouts and other costs.

Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost revenue billed, and interest applied. The third and fourth pages of Schedule 1 provide 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 summer gas cost revenue billed by rate class. Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the summer cost of gas account. Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital and shows the monthly beginning account balances, working capital allowable, the working capital revenue billed 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 commodity costs and the related volumes. Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

The Company has included in this filing the calculation of the occupant account disallowance/(credit) in accordance with the settlement agreement approved in Order 24-963 in docket DG 07-129/09-050. As shown on Schedules 10 and 11, the Company calculated a $147,275 disallowance in gas cost recovery associated with the occupant accounts and reduced its OffPeak gas costs by $31,121 and its Peak gas costs by $116,154.

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
SUMMER 2009 COST OF GAS RESULTS
DG 09-050
May 01, 2009 through October 31, 2009

		Filing 1/	Actual	Difference
Account 175.40				
Balance 10/31/08 - (Over) / Under		$ (1,969,485)	$ (1,969,485)	$ (0)
Prior Period Adjustment	2/	162,600	288,653	126,053
Interest 11/1/08 - 4/30/09		(24,071)	(23,228)	843
Beginning Balance 5/1/09		$ (1,830,956)	$ (1,704,061)	$ 126,895
Interest 5/1/09 - 10/31/09		(169)	(9,816)	(9,647)
Prior Period Adjustments		-	-	-
Interruptible Margin		-	-	-
280-Day Margin		-	-	-
Emergency Sales Margin		-	-	-
Non-Firm Transportation Margin		-	-	-
Other Transportation Related Margins		-	-	-
Capacity Release and Fixed Price Credits		-	-	-
Price Risk Management and FPO Admin Costs		-	-	-
Overhead		27,510	12,609	(14,901)
Occupant Disallowance/Credits		-	(31,121)	(31,121)
Total Adjustment to Costs		-	-	-
Gas Costs		$ 17,020,073	$ 13,849,279	$ (3,170,794)
Total Costs		$ 17,047,414	$ 13,820,952	$ (3,226,462)
Gas Cost Billed		$ (15,216,458)	$ (12,078,138)	$ 3,138,320
Total (Over) / Under 10/31/09		$ -	$ 38,753	$ 38,753
Bad Debts Account 175.54				
Balance 10/31/08 - (Over) / Under		$ (125,817)	$ (125,817)	$ (0)
Prior Period Adjustment		-	0	0
Interest 11/1/08 - 4/30/09		(2,023)	(2,023)	0
Beginning Balance 5/1/09		$ (127,840)	$ (127,840)	$ (0)
Bad Debt Costs		264,115	302,104	37,989
Bad Debt Billed		(135,300)	(122,194)	13,106
Interest		(975)	(623)	352
Total (Over) / Under 10/31/09		$ -	$ 51,447	$ 51,447
Working Capital Account 142.40				
Balance 10/31/08 - (Over) / Under		$ (68,107)	$ (68,107)	$ (0)
Prior Period Adjustment		-	0	0
Interest 11/1/08 - 4/30/09		(1,119)	(1,118)	1
Beginning Balance 5/1/09		$ (69,226)	$ (69,225)	$ 1
Working Capital Costs		109,779	14,058	(95,721)
Working Capital Billed		(40,009)	(36,658)	3,351
Interest		(544)	(1,277)	(733)
Total (Over) / Under 10/31/09		$ -	$ (93,103)	$ (93,103)
Total 175.40, 175.54, 142.40		$ -	$ (2,903)	$ (2,903)

1/ As filed March 16, 2009 in the Summer 2009 Cost of Gas DG 09-050.
On April 30, 2009 the NHPUC approved the March 16, 2009 filing in DG 09-050 in its Order No. 24,963.
2/ Prior Period Adjustment for Non-Daily Metered Delivery Service Imbalance for Summer 2008.

ENERGY NORTH NATURAL GAS, INC
SUMMER 2009 COST OF GAS RESULTS
DG 09-050
SUMMARY OF DEMAND CHARGES FOR PERIOD
May 01, 2009 through October 31, 2009

	Reference Actuals	Filing 1/	Actual	Difference
Supplies:				
ANE	Sch 2B line 3			
BP/Northeast Gas Market	Sch 2B line 4			
Subtotal Supply Demand Charges		$ 169,970	$ 218,226	$ 48,256
Pipelines:				
IGTS Iroquois	Sch 2B line 12	$ 160,191	$ 141,769	$ (18,422)
TGP Short Haul 2302 Z5-Z6	Sch 2B line 16	92,349	81,508	(10,841)
TGP Contract 8587 Zone 0-6	Sch 2B lines 17 + 50	2,158,540	1,868,615	(289,925)
TGP 33371 NET284	Sch 2B line 19	254,640	226,046	(28,594)
TGP 42076 Dracut	Sch 2B lines 20 + 47	379,200	334,122	(45,078)
Portland Natual Gas Pipeline	Sch 2B line 14 + 51	164,410	130,941	(33,469)
Subtotal Pipeline Demand Charges		$ 3,209,330	$ 2,783,001	$ (426,329)
LNG:				
Domac		$0	$0	$0
Propane				
EN Propane	Sch 2B line 37	$0	$16	$16
Storage:				
Demand & Capacity Charges		$0	$0	$0
Other				
Fees	Sch 2B line 39	$0	$ 3,000	$ 3,000
Transporation Capacity Credit		$ (319,515)	$ -	$ 319,515
		$ (319,515)	$ 3,000	$ 322,515
Total Demand Chrages (Forward to Page 3)		$ 3,059,785	$ 3,004,243	($55,542)

1/ Demand costs per Schedule 5A as filed in the Summer 2009 Cost of Gas DG 09-050 on March 16, 2009.

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ENERGY NORTH NATURAL GAS, INC
SUMMER 2009 COST OF GAS RESULTS
DG 09-050
SUMMARY OF COMMODITY COSTS FOR PERIOD
May 01, 2009 through October 31, 2009

	Reference Actuals	Filing 1/	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 2):		$3,059,785		$3,004,243		($55,542)	
TGP							
Therms	Sch 8, lines 5 + 32						
Cost	Sch 8, lines 5 + 32						(0.0555)
PNGTS							
Therms	Sch 8, line 11						
Cost	Sch 8, line 11						(0.4963)
BP/NEXEN							
Therms	Sch 8, line 21						
Cost	Sch 8, line 21						(0.0725)
Spot Gas							
Therms							
Cost							-
City Gate Delivered Supply							
Therms	Sch 8, line 8 + 9						
Cost	Sch 8, line 8 + 9						(0.0815)
Storage gas - commodity withdrawn							
Therms	Sch 8, line 30						
Cost	Sch 8, line 31						0.6983
Propane							
Therms	Sch 8, line 28						
Cost	Sch 8, line 28						2.0829
LNG							
Therms	Sch 8, line 25						
Cost	Sch 8, line 25						0.1931
Hedging (Gains) Losses							
	Sch 8, line 14						
Other- Cashout, Broker Penalty, Canadian Managed, Non-Firm costs							
Cost	Sch 8, line 43						
Subtotal:							
Volumes (net of fuel retention)		24,063,722		20,162,090		(3,901,632)	
Cost		$ 13,960,288	0.5801	$ 10,845,036	0.5379	$ (3,115,252)	(0.0422)
Total Demand and Commodity Costs		$ 17,020,073		$ 13,849,279		$ (3,170,794)	
Check - Sched 1				$ 13,849,279			
Demand (therms):							
Firm Gas Sales		23,350,050		19,796,271		(3,553,779)	
Lost Gas (Unaccounted For)		929,789		776,190		(153,599)	
Unbilled Therms		(329,250)		(510,899)		(181,649)	
Fuel Retention		-		-		-	
Company Use		113,133		100,528		(12,605)	
Total Demand		24,063,722		20,162,090		(3,901,632)	

1/ Commodity costs and forecasted volumes per Schedule 6 as filed in the Summer 2009 Cost of Gas DG 09-050 on March 16, 2009.

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ENERGY NORTH NATURAL GAS, INC
SUMMER 2009 COST OF GAS RESULTS
DG 09-050
May 01, 2009 through October 31, 2009

Weather Variance - Volume Impact	(A) Actual Volume	(B) Normal Volume	(C) Forecast Rate (a)		(A-B)*C Difference
TGP					
Spot Purchases					
PNGTS					
BP/Nexen					
Domac					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Volume Weather Varaince	20,162,090	20,779,859		$	(307,047)

Demand Variance - Commodity Costs	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate (a)		Difference
TGP					
Spot Purchases					
PNGTS					
BP/NEXEN					
City Gate Delivered Supply					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Demand Variance (Less: Fuel Retention)	24,063,722	20,162,090		$	(1,946,038)
Demand Variance Net of Weather Variance	-			$	(1,638,990)

Rate Variance - Commodity Costs	(A) Actual Volume	(B) Forecast Rate (a)	(C) Actual Rate		(C-B)*A Difference
TGP					
Spot Purchases					
PNGTS					
BP/NEXEN					
City Gate Delivered Supply					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Commodity Cost Rate Variance	20,162,090			$	(1,347,021)
Other Rate Variance (from page 2)					(55,542)
Hedge (Gains)/Loss (from page 3)					516,265
Total Rate Variance					($886,298)
Due to Weather Variance					(307,047)
Due to Demand Variance (from above)					(1,638,990)
Other- Cashout, Broker Penalty, Canadian Managed					(338,459)
Total Gas Cost Variance					($3,170,794)

(a) used actual rate if there was no forecasted rate

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ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

	FOR THE MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total
	DAYS IN MONTH	31	30	31	31	30	31	30	
1	BEGINNING BALANCE	$ 779,942	$ 1,316,030	$ 1,338,729	$ 1,813,808	$ 2,351,440	$ 2,935,448	$ 3,343,466	$ 779,942
2									
3	Add: ACTUAL COSTS	591,610	549,745	532,750	591,794	622,532	565,845	-	3,454,276
4									
5	Add: FUEL FINANCING COSTS	9,770	9,945	9,018	5,942	5,666	5,190		45,531
6									
7	Add: MISCELLANEOUS OVERHEADS								-
8									
9	Less: CUSTOMER BILLINGS	(3,541,223)	-	-	-	-	-	-	(3,541,223)
10	Estimated Unbilled	-	-	-	-	-	-		-
11	Reverse Prior Month Unbilled	3,541,223	-	-	-	-	-	-	3,541,223
12	Sub-Total Accrued Customer Billings	-	-	-	-	-	-	-	-
13									
14	Less: BROKER'S REVENUES	(23,679)	(486,550)	(24,288)	(11,377)	(10,422)	(16,023)	-	(572,339)
15									
16	Less: OCCUPANT (DISALLOW/CREDIT)	-	-	-	-	-	(116,154)		(116,154)
17									
18	NON FIRM MARGIN AND CREDITS	(44,502)	(53,982)	(46,745)	(54,470)	(40,820)	(39,494)	-	(280,012)
19									
20	ENDING BALANCE PRE INTEREST	1,313,141	1,335,188	1,809,463	2,345,699	2,928,396	3,334,812	3,343,466	3,311,244
21									
22	MONTH'S AVERAGE BALANCE	1,046,541	1,325,609	1,574,096	2,079,753	2,639,918	3,135,130	3,343,466	
23									
24	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	-	
25									
26	INTEREST APPLIED	2,889	3,541	4,345	5,741	7,052	8,654	-	32,222
27									
28	ENDING BALANCE	$ 1,316,030	$ 1,338,729	$ 1,813,808	$ 2,351,440	$ 2,935,448	$ 3,343,466	$ 3,343,466	$ 3,343,466

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

	FOR THE MONTH OF: DAYS IN MONTH	May-09 31	Jun-09 30	Jul-09 31	Aug-09 31	Sep-09 30	Oct-09 31	Nov-09 30	Total
1	BEGINNING BALANCE	$ (1,704,061)	$ (676,442)	$ (728,076)	$ (605,782)	$ (359,353)	$ (638,535)	$ 520,566	$ **(1,704,061)**
2									
3	Add: ACTUAL COSTS	3,309,561	1,719,348	1,556,738	1,437,488	1,362,571	4,463,573	-	**13,849,279**
4									
5	Add: MISCELLANEOUS OVERHEADS	4,585	4,585	860	860	860	860	-	**12,609**
6									
7									
8	Less: CUSTOMER BILLINGS	(1,288,570)	(2,228,199)	(1,663,169)	(1,344,088)	(1,289,031)	(2,110,955)	(2,154,126)	**(12,078,138)**
9	Estimated Unbilled	(994,676)	(540,171)	(310,468)	(156,969)	(509,220)	(1,672,313)		**(4,183,817)**
10	Reverse Prior Month Unbilled		994,676	540,171	310,468	156,969	509,220	1,672,313	**4,183,817**
11	Sub-Total Accrued Customer Billings	(2,283,247)	(1,773,694)	(1,433,466)	(1,190,589)	(1,641,282)	(3,274,049)	(481,813)	**(12,078,138)**
12									
13	Less: OCCUPANT (DISALLOW/CREDIT)	-	-	-	-	-	(31,121)	-	**(31,121)**
14									
15	ENDING BALANCE PRE INTEREST	$ **(673,161)**	$ **(726,203)**	$ **(603,944)**	$ **(358,023)**	$ **(637,204)**	$ **520,729**	$ **38,753**	$ 48,569
16									
17	MONTH'S AVERAGE BALANCE	(1,188,611)	(701,322)	(666,010)	(481,903)	(498,279)	(58,903)	279,659	
18									
19	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	-	
20									
21	INTEREST APPLIED	(3,281)	(1,873)	(1,838)	(1,330)	(1,331)	(163)		**(9,816)**
22									
23	ENDING BALANCE	$ **(676,442)**	$ **(728,076)**	$ **(605,782)**	$ **(359,353)**	$ **(638,535)**	$ **520,566**	$ **38,753**	$ **38,753**

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ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
PEAK PERIOD BAD DEBT
SHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total
	DAYS IN MONTH	31	30	31	31	30	31	30	
1	BEGINNING BALANCE	$ (220,838)	$ (207,515)	$ (195,445)	$ (183,611)	$ (170,438)	$ (156,085)	$ (143,116)	$ (220,838)
2									
3	Add: COST ALLOW	13,913	12,608	12,356	13,660	14,789	13,381	-	80,707
4									
5	Less: CUSTOMER BILLINGS	(17,899)	-	-	-	-	-	-	(17,899)
6	Estimated Unbilled	-	-	-	-	-	-		-
7	Reverse Prior Month Unbilled	17,899	-	-	-	-	-	-	17,899
8	Subtotal- Accrued Customer Billings	-	-	-	-	-	-	-	-
9									
10	ENDING BALANCE PRE INTEREST	$ (206,925)	$ (194,908)	$ (183,089)	$ (169,950)	$ (155,649)	$ (142,704)	$ (143,116)	$ (140,131)
11									
12	MONTH'S AVERAGE BALANCE	(213,882)	(201,211)	(189,267)	(176,781)	(163,044)	(149,395)	(143,116)	
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	-	
15									
16	INTEREST APPLIED	(590)	(537)	(522)	(488)	(436)	(412)		$ (2,985)
17									
18	ENDING BALANCE	$ (207,515)	$ (195,445)	$ (183,611)	$ (170,438)	$ (156,085)	$ (143,116)	$ (143,116)	$ (143,116)

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ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
OFF PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: DAYS IN MONTH	May-09 31	Jun-09 30	Jul-09 31	Aug-09 31	Sep-09 30	Oct-09 31	Nov-09	Total
1	BEGINNING BALANCE	$ (127,840)	$ (72,188)	$ (53,660)	$ (36,502)	$ (20,115)	$ (10,746)	$ 57,023	$ (127,840)
2									
3	Add: COST ALLOW	75,827	35,387	31,239	28,208	26,303	105,140	-	302,104
4									
5	Less: CUSTOMER BILLINGS	(10,916)	(20,484)	(16,104)	(13,216)	(13,184)	(23,396)	(24,895)	(122,194)
6	Estimated Unbilled	(8,983)	(5,189)	(3,043)	(1,570)	(5,279)	(19,318)		(43,381)
7	Reverse Prior Month Unbilled		8,983	5,189	3,043	1,570	5,279	19,318	43,381
8	Subtotal- Accrued Customer Billings	(19,898)	(16,691)	(13,958)	(11,743)	(16,892.58)	(37,435)	(5,576)	(122,194)
9									
10	ENDING BALANCE PRE INTEREST	$ (71,912)	$ (53,492)	$ (36,378)	$ (20,037)	$ (10,705)	$ 56,959	$ 51,447	$ 52,070
11									
12	MONTH'S AVERAGE BALANCE	(99,876)	(62,840)	(45,019)	(28,270)	(15,410)	23,107	54,235	
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	-	
15									
16	INTEREST APPLIED	(276)	(168)	(124)	(78)	(41)	64		$ (623)
17									
18	ENDING BALANCE	$ (72,188)	$ (53,660)	$ (36,502)	$ (20,115)	$ (10,745.55)	$ 57,023	$ 51,447	$ 51,447

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
GAS COSTS BY SOURCE
SCHEDULE 2 A

	FOR THE MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
1	**DEMAND**							
2								
3	ALBERTA NORTHEAST							
4	BP/NORTHEAST GAS MARKETS							
5	CANADIAN CAPACITY MANAGED							
6	TOTAL CANADIAN	$ 53,199	$ 25,612	$ 26,245	$ 27,443	$ 23,891	$ 30,690	**$ 187,080**
7								
8	PEAKING SUPPLY							
9								
10	TRANSPORT CAPACITY	$ 440,198	$ 610,056	$ 604,471	$ 549,070	$ 574,393	$ 578,821	**$ 3,357,010**
11	CAPACITY RELEASE ADJ	34,487	53,982	46,731	52,291	40,434	39,018	**266,941**
12	TOTAL TRANSPORT	$ 474,685	$ 664,038	$ 651,202	$ 601,360	$ 614,827	$ 617,839	**$ 3,623,952**
13								
14	STORAGE FIXED COSTS	$ 98,585	$ 99,178	$ 81,229	$ 93,521	$ 102,236	$ 99,585	**$ 574,333**
15								
16	LNG	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
17								
18	PROPANE	$ 12	$ (12)	$ -	$ -	$ -	$ 16	**$ 16**
19								
20	OTHER	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	**$ 3,000**
21								
22	**TOTAL DEMAND**	**$ 643,979**	**$ 809,317**	**$ 779,176**	**$ 742,824**	**$ 761,454**	**$ 768,630**	**$ 4,505,380**
23								
24	**COMMODITY**							
25								
26	BP/NORTHEAST GAS MARKETS							
27	DTE ENERGY							
28	SEMPRA							
29	TOTAL CANADIAN COMMODITY	$ 902,736	$ 883,925	$ 1,038,262	$ 866,540	$ 750,048	$ 1,049,754	**$ 5,491,266**
30								
31	PIPELINE TRANSPORT	$ 114,890	$ 47,157	$ 14,778	$ 11,027	$ 21,400	$ 40,584	**$ 249,836**
32								
33	GAS SUPPLY	$ 2,945,818	$ 512,965	$ 336,462	$ 507,113	$ 870,830	$ 2,871,424	**$ 8,044,612**
34								
35	STORAGE	$ (181,873)	$ (30,836)	$ (64,346)	$ (77,946)	$ (277,653)	$ (139,794)	**$ (772,447)**
36								
37	LNG	$ 11,665	$ 12,440	$ 19,057	$ 11,058	$ 11,727	$ 11,581	**$ 77,528**
38								
39	PROPANE	$ 11,177	$ (2,401)	$ 99	$ 8,132	$ (1,083)	$ 1,739	**$ 17,663**
40								
41	TAXES	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
42								
43	SUPPLIER CASHOUT	$ 28,965	$ 37,500	$ 10,690	$ 13,402	$ 2,303	$ 10,706	**$ 103,567**
44								
45	CANADIAN CAPACITY MANAGED	$ (105,360)	$ (62,239)	$ (139,030)	$ 76,791	$ (162,949)	$ (44,093)	**$ (436,880)**
46								
47	BROKER INVENTORY	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
48								
49	BROKER IMBALANCE	$ (3,941)	$ (777)	$ (135)	$ (1)	$ (9)	$ (282)	**$ (5,145)**
50								
51	**SUBTOTAL COMMODITY COST**	$ 3,724,079	$ 1,397,734	$ 1,215,838	$ 1,416,115	$ 1,214,614	$ 3,801,618	**$ 12,769,999**
52								
53	OFF SYSTEM SALES	$ (471,717)	$ -	$ (1,931)	$ (154,121)	$ (23,777)	$ (59,074)	**$ (710,620)**
54								
55	NON-FIRM COST	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
56								
57	TOTAL COMMODITY COST	**$ 3,252,362**	**$ 1,397,734**	**$ 1,213,907**	**$ 1,261,994**	**$ 1,190,837**	**$ 3,742,544**	**$ 12,059,379**

GAS COSTS SUMMARY
SCHEDULE 2 A

	FOR THE MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
59								
60	**Total Peak Demand**	$ 257,918	$ 228,849	$ 241,572	$ 260,023	$ 254,097	$ 258,679	$ 1,501,137
61	**Off-Peak Demand**	386,062	580,468	537,604	482,802	507,357	509,950	3,004,243
62	**Total Demand**	$ 643,979	$ 809,317	$ 779,176	$ 742,824	$ 761,454	$ 768,630	$ 4,505,380
63								
64	**Total Peak Commodity**	$ 333,692	$ 320,896	$ 291,179	$ 331,772	$ 368,434	$ 307,166	$ 1,953,139
65	**Off-Peak Commodity**	2,923,500	1,138,879	1,019,134	954,686	855,214	3,953,623	10,845,036
66	**Total Commodity**	$ 3,257,192	$ 1,459,776	$ 1,310,312	$ 1,286,458	$ 1,223,648	$ 4,260,789	$ 12,798,175
67								
68	**Firm Sendout Costs**	$ 3,901,171	$ 2,269,093	$ 2,089,488	$ 2,029,282	$ 1,985,103	$ 5,029,418	$ 17,303,555

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Tab 14

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2 B

	FOR THE MONTH OF:		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total Off Peak	Total Peak	Total
1	**DEMAND**										
2	**Fixed Charges/Supply**										
3	ANE	OP									
4	BP/Northeast Gas Market	OP									
5	Total Canadian Purchases		$ 58,211.15	$ 30,617.95	$ 31,749.94	$ 28,573.92	$ 33,514.03	$ 35,559.30	$ 218,226	$ -	$ 218,226
6											
7	**PEAKING SUPPLY**										
8	Granite Ridge	PK	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ -	$ 120,000	$ 120,000
9	Chevron	PK	$ (3,001.37)	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,001)	$ (3,001)
10											
11	**Transport Capacity**										
12	IROQUOIS 470-01 RTS	OP	$ 23,939.77	$ 26,619.47	$ 23,706.05	$ 20,473.66	$ 23,584.63	$ 23,445.48	$ 141,769	$ -	$ 141,769
13	NFGS NO2358 FST	PK	(10,683.54)	18,241.2	20,496.6	20,496.6	15,864.9	18,143.8	0	82,560	82,560
14	PNGTS FT-1999-001	OP	21,332.92	(34,746.30)	73,892.07	21,922.94	18,201.36	12,657.36	113,260	0	113,260
15	TGP 632 FTA Zone 4-6	PK	80,634.10	40,850.84	60,424.41	60,424.41	60,424.41	60,023.89	0	362,782	362,782
16	TGP 2302 FTA Zone 5-6	OP	13,621.59	13,646.24	13,577.22	13,577.22	13,577.22	13,508.20	81,508	0	81,508
17	TGP 8587 FTA Zone 0-6	OP	236,298.51	365,785.73	284,924.16	283,687.68	316,672.03	321,530.58	1,808,899	0	1,808,899
18	TGP 11234 FTA Zone 4-6	PK	47,342.00	23,579.92	34,129.38	35,166.02	33,670.58	35,742.62	0	209,631	209,631
19	TGP 33371 NET-NE	OP	13,983.98	62,227.65	37,506.35	37,506.35	36,583.08	38,238.64	226,046	0	226,046
20	TGP 42076 FTA	OP	13,729.12	93,851.48	55,815.08	55,815.08	55,815.08	55,530.68	330,557	0	330,557
21									0	0	0
22	SubTotal Transport Capacity		$ 440,198.45	$ 610,056.27	$ 604,471.32	$ 549,069.96	$ 574,393.27	$ 578,821.21	$ 2,702,038	$ 654,972	$ 3,357,010
23											
24											
25	**Storage Fixed**										
26	Dominion - Storage Demand	PK							$ -	$ 15,952	$ 15,952
27	TGP FSMA - Storage Demand	PK							0	287,866	287,866
28	Nat'l Fuel - Storage Demand	PK							0	215,304	215,304
29	Honeoye - Storage Demand	PK							0	61,211	61,211
30	Sempra - Storage Demand	PK							0	(6,000)	(6,000)
31	Total Storage		$ 98,584.66	$ 99,178.33	$ 81,228.93	$ 93,520.86	$ 102,235.74	$ 99,584.86	$ -	$ 574,333	$ 574,333
32											
33	**LNG**										
34	LNG - Res Charge (Distrigas)	PK	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
35											
36	**PROPANE**										
37	Energy North Propane	OP	$ 11.82	$ (11.91)	$ -	$ -	$ -	$ 15.88	$ 16	$ -	$ 16
38											
39	**ICE Fees**	OP	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 3,000	$ -	$ 3,000
40											
41	**Canadian**										
42	Capacity Managed - Canadian	PK	$ (5,012.05)	$ (5,005.57)	$ (5,505.39)	$ (1,130.88)	$ (9,622.75)	$ (4,869.51)	$ -	$ (31,146)	$ (31,146)
43											
44	**Demand Subtotal**		$ 609,492.66	$ 755,335.07	$ 732,444.80	$ 690,533.86	$ 721,020.29	$ 729,611.74	$ 2,923,280	$ 1,315,158	$ 4,238,438
45											
46	Capacity Release Adjustment										
47	TGP 42076 FTA	OP							$ 3,565	$ -	$ 3,565
48	TGP 632 FSMA	PK									
49	TGP 11234 FTA	PK									
50	TGP 8587FTA	OP									
51	PNGTS FT-1999-001	OP									
52			$ 34,486.80	$ 53,981.80	$ 46,730.75	$ 52,290.52	$ 40,433.80	$ 39,017.80	$ 80,962	$ 185,979	$ 266,941
53											
54	**TOTAL DEMAND**		$ 643,979.46	$ 809,316.87	$ 779,175.55	$ 742,824.38	$ 761,454.09	$ 768,629.54	3,004,243	$ 1,501,137	$ 4,505,380

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Tab 14

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2 B

	FOR THE MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total Off Peak	Total Peak	Total
55	**COMMODITY**									
56										
57	**Canadian Supply**									
58	BP/Northeast Gas Market									
59	Nexen									
60	Sempra									
61	Total Canadian Commodity	$ 902,736.01	$ 883,925.41	$ 1,038,262.32	$ 866,540.08	$ 750,048.24	$ 1,049,753.84	$ 5,491,266	$ -	$ 5,491,266
62										
63	**Pipeline Transport**									
64	ANE Union/Transgas	$ 2,043.95	$ 2,246.23	$ 2,220.85	$ 2,303.68	$ 2,375.65	$ 2,312.62	$ 13,503		$ 13,503
65										
66	Dominion	$ (163.69)	$ -	$ -	$ -	$ -	$ -	$ (164)	$ -	$ (164)
67	Iroquois	547.74	588.24	572.18	589.44	588.33	568.95	3,455	-	3,455
68	El Paso	107,052.76	49,707.74	11,985.06	8,133.87	18,435.72	37,624.17	232,939	-	232,939
69	Honeye	-	-	-	-	-	78.71	79		79
70	National Fuel	5,409.69	(5,390.39)	-	-	-	-	19	-	19
71	PNGTS	-	4.81	-	-	-	-	5	-	5
72	Total TGP Transportation	$ 112,846.50	$ 44,910.40	$ 12,557.24	$ 8,723.31	$ 19,024.05	$ 38,271.83	$ 236,333	$ -	$ 236,333
73										
74	Total Pipeline Transport	$ 114,890.45	$ 47,156.63	$ 14,778.09	$ 11,026.99	$ 21,399.70	$ 40,584.45	$ 249,836	$ -	$ 249,836
75										
76	**City Gate Supply**									
77	Distrigas FCS 064	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	VPEM	$ 4,829.61	$ 62,041.79	$ 96,405.00	$ 24,463.89	$ 32,811.43	$ 518,244.72	$ 738,796	$ -	$ 738,796
79										
80	**PNGTS Gas Supply Purchases**									
81	Emera	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Total PNGTS Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83										
84	**TGP Gas Supply Purchases**									
85	Andarko									
86	ANP									
87	Cargill									
88	Cheniere									
89	Chevron									
90	Colonial Energy									
91	Cokinos									
92	Coral									
93	Conectiv									
94	Constellation Energy									
95	Devon Gas									
96	DTE Energy									
97	Emera									
98	ETC									
99	FEMT									
100	Hess									
101	L. Dreyfus									
102	Macquarie									
103	Repsol									
104	NJ Energy									
105	Shell									
106	Tenaska									
107	Total Gas & Power									
108	UBS									
109	VPEM									
110	Sub Total	$ 1,032,345.23	$ 192,068.82	$ 45,283.26	$ 175,341.42	$ 502,395.43	$ 1,428,874.59	$ 3,376,309	$ -	$ 3,376,309
111	Hedging Gain/Loss Peak PK	333,692.00	320,896.30	291,178.50	331,771.90	368,434.30	307,166.00		$ 1,953,139	$ 1,953,139
112	Hedging Gain/Loss Off Peak OP	1,579,781.00	-	-	-	-	1,135,383.00	2,715,164	-	2,715,164
113	Total	$ 2,945,818.23	$ 512,965.12	$ 336,461.76	$ 507,113.32	$ 870,829.73	$ 2,871,423.59	$ 6,091,473	$ 1,953,139	$ 8,044,612
114										
115										
116	**Storage**									
117	WITHDRAWALS Off Peak	$ 25,580.89	$ 73,845.84	$ 55.38	$ -	$ 67,379.11	$ 60,967.60	227,829	-	227,829
118	INJECTIONS	(207,453.52)	(104,681.63)	(64,401.30)	(77,946.21)	(345,032.16)	(200,761.37)	(1,000,276)	-	(1,000,276)
119	Total Storage	$ (181,872.63)	$ (30,835.79)	$ (64,345.92)	$ (77,946.21)	$ (277,653.05)	$ (139,793.77)	$ (772,447)	$ -	$ (772,447)
120										
121	**LNG**									
122	LNG VAPOR	$ 11,665.29	$ 12,439.67	$ 19,057.07	$ 11,058.41	$ 11,726.65	$ 11,580.74	$ 77,528	$ -	$ 77,528
123	Total LNG	$ 11,665.29	$ 12,439.67	$ 19,057.07	$ 11,058.41	$ 11,726.65	$ 11,580.74	$ 77,528	$ -	$ 77,528
124					**THIS PAGE HAS BEEN REDACTED**					

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Tab 14

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2 B

	FOR THE MONTH OF:		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total Off Peak	Total Peak	Total
125	**PROPANE**										
126	Propane Sendout		$ 7,550.76	$ 2,294.27	$ 99.05	$ 1,591.54	$ 2,187.19	$ (1,335.87)	$ 12,387	$ -	$ 12,387
127	Energy North Propane		3,626.64	(4,695.48)	-	6,540.06	(3,270.03)	3,074.51	5,276	-	$ 5,276
128	**TOTAL PROPANE**		$ 11,177.40	$ (2,401.21)	$ 99.05	$ 8,131.60	$ (1,082.84)	$ 1,738.64	$ 17,663	$ -	$ 17,663
129											
130	Taxes - West Virginia	OP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131											
132	Broker Cashout	OP	$ 28,965.09	$ 37,500.32	$ 10,690.36	$ 13,401.89	$ 2,303.24	$ 10,705.84	$ 103,567	$ -	$ 103,567
133											
134	Capacity Managed - Canadian	OP	$ (105,359.78)	$ (62,239.44)	$ (139,029.95)	$ 76,790.51	$ (162,948.58)	$ (44,092.74)	$ (436,880)	$ -	$ (436,880)
135											
136	Broker Inventory	PK	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
137											
138	Broker's Imbalance Revenues	OP	$ (3,940.65)	$ (776.84)	$ (134.91)	$ (1.44)	$ (9.08)	$ (282.38)	$ (5,145)	$ -	$ (5,145)
139											
140	**TOTAL COMMODITY**		$ 3,728,909.02	$ 1,459,775.66	$ 1,312,242.87	$ 1,440,579.04	$ 1,247,425.44	$ 4,319,862.93	$ 11,555,656	$ 1,953,139.00	$ 13,508,795
141											
142	OFF SYSTEM SALES COST	OP	$ (471,717.41)	$ -	$ (1,930.55)	$ (154,120.95)	$ (23,776.99)	$ (59,074.00)	$ (710,620)	-	$ (710,620)
143											
144	NON-FIRM COST	OP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -
145											
146	**NET COMMODITY COST**		$ 3,257,191.61	$ 1,459,775.66	$ 1,310,312.32	$ 1,286,458.09	$ 1,223,648.45	$ 4,260,788.93	$ 10,845,036	$ 1,953,139.00	$ 12,798,175

	FOR THE MONTH OF:		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
147	Total Peak Demand	PK	$ 257,917.60	$ 228,848.56	$ 241,571.73	$ 260,022.53	$ 254,097.30	$ 258,679.42	$ 1,501,137
148	Total Peak Commodity	PK	333,692.00	320,896.30	291,178.50	331,771.90	368,434.30	307,166.00	1,953,139.00
149	Total Peak Gas Costs		$ 591,609.60	$ 549,744.86	$ 532,750.23	$ 591,794.43	$ 622,531.60	$ 565,845.42	$ 3,454,276
150									
151	Off-Peak Demand	OP	$ 386,061.86	$ 580,468.31	$ 537,603.82	$ 482,801.85	$ 507,356.79	$ 509,950.12	$ 3,004,243
152	Off-Peak Commodity	OP	2,923,499.61	1,138,879.36	1,019,133.82	954,686.19	855,214.15	3,953,622.93	10,845,036
153	Total Off Peak Gas Costs		$ 3,309,561.47	$ 1,719,347.67	$ 1,556,737.64	$ 1,437,488.04	$ 1,362,570.94	$ 4,463,573.05	$ 13,849,279
154									
155	Firm Sendout Costs		$ 3,901,171.07	$ 2,269,092.53	$ 2,089,487.87	$ 2,029,282.47	$ 1,985,102.54	$ 5,029,418.47	$ 17,303,555

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 3
SUMMER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	May-09 Winter	May-09 Summer	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total Off-Peak	Total Peak
1	**VOLUMES**										
2	**RESIDENTIAL**										
3	R-1	46,522	23,644	63,843	61,177	48,942	43,829	60,891	43,546	345,872	46,522
4	R-1 FPO	4,420	2,009	33	-	-	-	-	3,683	5,725	4,420
5	R-3	1,284,234	760,749	1,608,910	1,354,406	1,087,688	1,109,301	2,084,898	1,926,915	9,932,867	1,284,234
6	R-3 FPO	309,314	176,503	(5,954)	596	526	-	309	308,576	480,556	309,314
7	R-4	250,556	67,714	260,122	122,384	96,311	88,218	157,311	75,205	867,265	250,556
8	R-4 FPO	52,974	17,413	6,293	(401)	-	-	-	22,832	46,137	52,974
9	Total Residential	1,948,020	1,048,032	1,933,247	1,538,162	1,233,467	1,241,348	2,303,409	2,380,757	11,678,422	1,948,020
10											
11	**COMMERCIAL/INDUSTRIAL**										
12	G41 - G43	1,109,583	503,306	951,261	657,780	536,547	514,261	1,075,245	1,316,110	5,554,510	1,109,583
13	G41 - G43 FPO	138,403	55,546	2,246	(30)	-	(1)	-	77,495	135,256	138,403
14	G51 - G63	342,149	193,211	527,309	488,105	432,605	441,694	520,640	356,098	2,959,662	342,149
15	G51 - G63 FPO	41,563	19,163	-	-	-	-	-	18,631	37,794	41,563
16	Total Comm/Industrial	1,631,698	771,226	1,480,816	1,145,855	969,152	955,954	1,595,885	1,768,334	8,687,222	1,631,698
17	**Total Sales**	3,579,718	1,819,258	3,414,063	2,684,017	2,202,619	2,197,302	3,899,294	4,149,091	20,365,644	3,579,718
18											
19	**TRANSPORTATION**										
20	G41 - G43	1,032,781	312,064	726,147	531,869	464,970	481,631	842,475	1,085,587	4,444,743	1,032,781
21	G51 - G63	2,015,268	61,998	2,121,270	2,188,134	2,093,190	2,061,054	2,223,543	2,404,030	13,153,219	2,015,268
22	**Total Transportation**	3,048,049	374,062	2,847,417	2,720,003	2,558,160	2,542,685	3,066,018	3,489,617	17,597,962	3,048,049
23											
24	**Total Volumes**	**6,627,767**	**2,193,320**	**6,261,480**	**5,404,020**	**4,760,779**	**4,739,987**	**6,965,312**	**7,638,708**	37,963,606	6,627,767
25											
26	**RATES**										
27	R-1	$ 0.9380	$ 0.6644	$ 0.6481	$ 0.6186	$ 0.6061	$ 0.5897	$ 0.5473	$ 0.5194		
28	R-1 FPO	1.2745	0.6644	0.6481	0.6186	0.6061	0.5897	0.5473	0.5194		
29	R-3	0.9380	0.6644	0.6481	0.6186	0.6061	0.5897	0.5473	0.5194		
30	R-3 FPO	1.2745	0.6644	0.6481	0.6186	0.6061	0.5897	0.5473	0.5194		
31	R-4	0.9380	0.6644	0.6481	0.6186	0.6061	0.5897	0.5473	0.5194		
32	R-4 FPO	1.2745	0.6644	0.6481	0.6186	0.6061	0.5897	0.5473	0.5194		
33	C/I Sales G41 to G43	0.9381	0.6649	0.6500	0.6196	0.6072	0.5908	0.5486	0.5199		
34	C/I Sales G41 to G43 FPO	1.2746	0.6649	0.6500	0.6196	0.6072	0.5908	0.5486	0.5199		
35	C/I Transport G41 to G43	(0.0001)	-	-	-	-	-	-	(0.0003)		
36	C/I Sales G51 to G63	0.9371	0.6629	0.6471	0.6174	0.6048	0.5891	0.5509	0.5179		
37	C/I Sales G51 to G63 FPO	1.2740	0.6629	0.6471	0.6174	0.6048	0.5891	0.5509	0.5179		
38	C/I Transport G51 to G63	(0.0001)	-	-	-	-	-	-	(0.0003)		
39											
40											
41	**REVENUES**										
42	R-1	$ 43,638	$ 15,709	$ 41,377	$ 37,844	$ 29,664	$ 25,846	$ 33,326	$ 22,618	**$ 206,383**	**$ 43,638**
43	R-1 FPO	5,633	1,335	21	-	-	-	-	1,913	**3,269**	**5,633**
44	R-3	1,204,611	505,442	1,042,735	837,836	659,248	654,155	1,141,065	1,000,840	**5,841,319**	**1,204,611**
45	R-3 FPO	394,221	117,269	(3,859)	369	319	-	169	160,274	**274,541**	**394,221**
46	R-4	235,022	44,989	168,585	75,707	58,374	52,022	86,096	39,061	**524,835**	**235,022**
47	R-4 FPO	67,515	11,569	4,078	(248)	-	-	-	11,859	**27,259**	**67,515**
48	C/I Sales G41 to G43	1,040,900	334,648	618,320	407,560	325,791	303,825	589,879	684,246	**3,264,270**	**1,040,900**
49	C/I Sales G41 to G43 FPO	176,408	36,933	1,460	(19)	-	(1)	-	40,290	**78,663**	**176,408**
50	C/I Transport G41 to G43	(103)	-	-	-	-	-	-	(326)	**(326)**	**(103)**
51	C/I Sales G51 to G63	320,628	128,080	341,222	301,356	261,640	260,202	286,821	184,423	**1,763,742**	**320,628**
52	C/I Sales G51 to G63 FPO	52,951	12,703	-	-	-	-	-	9,649	**22,352**	**52,951**
53	C/I Transport G51 to G63	(202)	-	-	-	-	-	-	(721)	**(721)**	**(202)**
54	**Gas Cost Revenue**	**$ 3,541,223**	**$ 1,208,676**	**$ 2,213,939**	**$ 1,660,405**	**$ 1,335,035**	**$ 1,296,050**	**$ 2,137,356**	**$ 2,154,126**	$ 12,005,586	$ 3,541,223
55											
56	Less Occupant Billing		4,403	4,736	4,159	1,816	6,756	10,411	-	32,280	-
57											
58	Less Summer Proration		(84,297)	(18,996)	(6,923)	(10,869)	263	15,990	-	(104,832)	-
59	Summer Gas Cost Revenue Billed		**$ 1,288,570**	**$ 2,228,199**	**$ 1,663,169**	**$ 1,344,088**	**$ 1,289,031**	**$ 2,110,955**	**$ 2,154,126**	$ 12,078,138	
60											
61	Winter Gas Costs Revenue Billed	**$ 3,541,223**								-	**$ 3,541,223**
62											
63	**Total Gas Costs Billed**	**$ 3,541,223**	**$ 1,288,570**	**$ 2,228,199**	**$ 1,663,169**	**$ 1,344,088**	**$ 1,289,031**	**$ 2,110,955**	**$ 2,154,126**	$ 12,078,138	$ -
64											
65	Bad Debt Revenue Billed	$ 17,899	$ 10,916	$ 20,484	$ 16,104	$ 13,216	$ 13,184	$ 23,396	$ 24,895	**$ 122,194**	**$ 17,899**
66	Working Capital Gas Cost Billed	$ 14,319	$ 3,275	$ 6,145	$ 4,831	$ 3,965	$ 3,955	$ 7,019	$ 7,468	**$ 36,658**	**$ 14,319**
67	Broker Revenue		$ 23,679	$ 486,550	$ 24,288	$ 11,377	$ 10,422	$ 16,023	$ -	$ -	**$ 572,339**
68											
69	**Total Billings**	**$ 3,573,440**	**$ 1,326,439**	**$ 2,741,378**	**$ 1,708,393**	**$ 1,372,645**	**$ 1,316,591**	**$ 2,157,393**	**$ 2,186,489**	$ 12,236,990	$ 604,556

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)

	FOR MONTH OF:	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
1	Firm Gas Purchases		3,440,210	2,885,670	2,413,200	2,030,230	2,920,570	6,472,210	20,162,090
2	Firm Sales		1,819,258	3,414,063	2,684,017	2,202,619	2,197,302	3,899,294	16,216,553
3	Company Use		0	0	0	0	0	0	-
4	Unaccounted For %		3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	
5	Unaccounted For Gas		123,848	103,884	86,875	73,088	105,141	233,000	725,835
6	COG Factor- Gas Cost Only		$0.6644	$0.6246	$0.6122	$0.5999	$0.5788	$0.5194	
7	COG Factor- Bad Debt Factor		$0.0060	$0.0060	$0.0060	$0.0060	$0.0060	$0.0060	
8	COG Factor- Working Capital Factor		$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
9									
10	Unbilled Volume								
11	Beginning Bal		-	1,497,104	864,827	507,135	261,658	879,785	
12	Incremental Unbilled		1,497,104	(632,277)	(357,692)	(245,477)	618,127	2,339,916	
13	Ending Balance		1,497,104	864,827	507,135	261,658	879,785	3,219,702	
14									
15	COG Factor- Gas Cost Only		$0.6644	$0.6246	$0.6122	$0.5999	$0.5788	$0.5194	
16	Gross Unbilled Gas Cost		$994,676	$540,171	$310,468	$156,969	$509,220	$1,672,313	
17									
18	Monthly Incremental Gas Cost		$994,676	($454,505)	($229,703)	($153,500)	$352,251	$1,163,093	
19									
20	COG Factor- Bad Debt Only		$0.0060	$0.0060	$0.0060	$0.0060	$0.0060	$0.0060	
21	Gross Unbilled Bad Debt Cost		$8,983	$5,189	$3,043	$1,570	$5,279	$19,318	
22									
23	Monthly Incremental Bad Debt Cost		$8,983	($3,794)	($2,146)	($1,473)	$3,709	$14,039	
24									
25	COG Factor- Working Capital Only		$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
26	Gross Unbilled Working Capital Cost		$2,695	$1,557	$913	$471	$1,584	$5,795	
27									
28	Monthly Incremental Working Capital Cost		$2,695	($1,138)	($644)	($442)	$1,113	$4,212	

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
1								
2	INTERRUPTIBLE							
3								
4	280 DAY							
5								
6	TRANSPORTATION							
7								
8								
9	OFF SYSTEM SALES							
10								
11	CAPACITY RELEASE							
12								
13	TOTAL NON FIRM MARGIN AND CREDITS	$ (44,502)	$ (53,982)	$ (46,745)	$ (54,470)	$ (40,820)	$ (39,494)	$ (280,012)

This page is filed under protective Order No. 24,963 dated April 30, 2009 in DG 09-050.

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ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
PEAK WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	May-09 31	Jun-09 30	Jul-09 31	Aug-09 31	Sep-09 30	Oct-09 31	Nov-09	Total
1	BEGINNING BALANCE	$ (518,179)	$ (520,841)	$ (521,634)	$ (522,632)	$ (523,587)	$ (524,458)	$ (525,428)	$ **(518,179)**
2									
3	Add: COST ALLOW	660	598	441	487	527	477		**3,189**
4									
5	Less: CUSTOMER BILLINGS	(14,319)	-	-	-	-	-	-	**(14,319)**
6	Estimated Unbilled	-	-	-	-	-	-		**-**
7	Reverse Prior Month Unbilled	12,428	-	-	-	-	-	-	**12,428**
8	Subtotal: Accrued Customer Billings	(1,890)	-	-	-	-	-	-	**(1,890)**
9									
10	ENDING BALANCE PRE INTEREST	**$ (519,409)**	**$ (520,244)**	**$ (521,193)**	**$ (522,145)**	**$ (523,060)**	**$ (523,981)**	**$ (525,428)**	**$ (516,880)**
11									
12	MONTH'S AVERAGE BALANCE	(518,794)	(520,542)	(521,413)	(522,389)	(523,323)	(524,219)		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15	INTEREST APPLIED	(1,432)	(1,390)	(1,439)	(1,442)	(1,398)	(1,447)		**(8,548)**
16	ENDING BALANCE	**$ (520,841)**	**$ (521,634)**	**$ (522,632)**	**$ (523,587)**	**$ (524,458)**	**$ (525,428)**	**$ (525,428)**	**$ (525,428)**

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
OFF-PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH	May-09 31	Jun-09 30	Jul-09 31	Aug-09 31	Sep-09 30	Oct-09 31	Nov-09	Total
1	BEGINNING BALANCE	$ (69,225)	$ (71,399)	$ (74,528)	$ (77,514)	$ (79,951)	$ (84,003)	$ (91,430)	**(69,225)**
2									
3	Add:ACTUAL COST	3,990	2,073	1,411	1,303	1,235	4,046	-	**$ 14,058**
4									
5	Less: CUSTOMER BILLINGS	(3,275)	(6,145)	(4,831)	(3,965)	(3,955)	(7,019)	(7,468)	**(36,658)**
6	Estimated Unbilled	(2,695)	(1,557)	(913)	(471)	(1,584)	(5,795)		**(13,014)**
7	Reverse Prior Month Unbilled		2,695	1,557	913	471	1,584	5,795	**13,014**
8	Subtotal: Accrued Customer Billings	(5,969)	(5,007)	(4,187)	(3,523)	(5,068)	(11,231)	(1,673)	**(36,658)**
9									
10	ENDING BALANCE PRE INTEREST	**$ (71,205)**	**$ (74,333)**	**$ (77,304)**	**$ (79,734)**	**$ (83,784)**	**$ (91,188)**	**$ (93,103)**	**$ (91,826)**
11									
12	MONTH'S AVERAGE BALANCE	(70,215)	(72,866)	(75,916)	(78,624)	(81,868)	(87,595)		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15	INTEREST APPLIED	(194)	(195)	(210)	(217)	(219)	(242)		**(1,277)**
16	ENDING BALANCE	**$ (71,399)**	**$ (74,528)**	**$ (77,514)**	**$ (79,951)**	**$ (84,003.00)**	**$ (91,430)**	**$ (93,103)**	**$ (93,103)**

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 6
OFF PEAK BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
1	Demand	$ 386,062	$ 580,468	$ 537,604	$ 482,802	$ 507,357	$ 509,950	$ 3,004,243
2	Commodity	2,923,500	1,138,879	1,019,134	954,686	855,214	3,953,623	10,845,036
3	Total Gas Costs	$ 3,309,561	$ 1,719,348	$ 1,556,738	$ 1,437,488	$ 1,362,571	$ 4,463,573	$ 13,849,279
4								
5	Lead Lag Days	13.54	13.54	10.18	10.18	10.18	10.18	
6	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7								
8	Working Capital Rate	0.00121	0.00121	0.00091	0.00091	0.00091	0.00091	
9								
10	Total Working Capital Costs	$ 3,990	$ 2,073	$ 1,411	$ 1,303	$ 1,235	$ 4,046	$ 14,058
11								
12	Prior Period (Over)Undercollection	$ (328,248)	$ (328,248)	$ (328,248)	$ (328,248)	$ (328,248)	$ (328,248)	$ (1,969,485)
13								
14	Subtotal Gas Costs, Working Capital & Under Collection	$ 2,985,304	$ 1,393,173	$ 1,229,901	$ 1,110,544	$ 1,035,559	$ 4,139,372	
15								
16	Bad Debt Rate	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	
17								
18	Total Bad Debt Cost	$ 75,827	$ 35,387	$ 31,239	$ 28,208	$ 26,303	$ 105,140	$ 302,104

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 6
PEAK BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
1	Demand	$ 257,918	$ 228,849	$ 241,572	$ 260,023	$ 254,097	$ 258,679	$ 1,501,137
2	Commodity	333,692	320,896	291,179	331,772	368,434	307,166	1,953,139
3	Margins and Capacity Release	(44,502)	(53,982)	(46,745)	(54,470)	(40,820)	(39,494)	(280,012)
4	Total Gas Costs	$ 547,108	$ 495,763	$ 486,005	$ 537,325	$ 581,712	$ 526,352	$ 3,174,264
5								
6	Working Capital Rate	0.00121	0.00121	0.00091	0.00091	0.00091	0.00091	
7								
8	Total Working Capital Costs	$ 660	$ 598	$ 441	$ 487	$ 527	$ 477	$ 3,189
9								
10	Prior Period (Over)Undercollection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11								
12	Subtotal Gas Costs, Working Capital & Under Collection	$ 547,767	$ 496,361	$ 486,446	$ 537,812	$ 582,239	$ 526,829	$ 3,177,454
13								
14	Bad Debt Rate	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	
15								
16	Total Bad Debt Cost	$ 13,913	$ 12,608	$ 12,356	$ 13,660	$ 14,789	$ 13,381	$ 80,707

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 7
WORKING CAPITAL & BAD DEBT REVENUE BILLED

	FOR MONTH OF:	May-09 Winter	May-09 Summer	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total OffPeak	Total Peak
1	**VOLUMES**										
2	**RESIDENTIAL**										
3	R-1, R-3 and R-4	1,581,312	852,107	1,932,875	1,537,967	1,232,941	1,241,348	2,303,100	2,045,666	**11,146,004**	**1,581,312**
4	R-1, R-3 and R-4 FPO	366,708	195,925	372	195	526	-	309	335,091	**532,418**	**366,708**
5											
6	**COMMERCIAL/INDUSTRIAL**										
7	G41 - G43	1,109,583	503,306	951,261	657,780	536,547	514,261	1,075,245	1,316,110	**5,554,510**	**1,109,583**
8	G41 - G43 FPO	138,403	55,546	2,246	(30)	-	(1)	-	77,495	**135,256**	**138,403**
9	G51 - G63	342,149	193,211	527,309	488,105	432,605	441,694	520,640	356,098	**2,959,662**	**342,149**
10	G51 - G63 FPO	41,563	19,163	-	-	-	-	-	18,631	**37,794**	**41,563**
11											
12	**TRANSPORTATION**										
13	G41 - G43	1,032,781	312,064	726,147	531,869	464,970	481,631	842,475	1,085,587	**4,444,743**	**1,032,781**
14	G51 - G63	2,015,268	61,998	2,121,270	2,188,134	2,093,190	2,061,054	2,223,543	2,404,030	**13,153,219**	**2,015,268**
15											
16	**TOTAL VOLUME**	**6,627,767**	**2,193,320**	**6,261,480**	**5,404,020**	**4,760,779**	**4,739,987**	**6,965,312**	**7,638,708**	**37,963,606**	**6,627,767**
17											
18	**WORKING CAPITAL RATES**										
19	Residential R1 & R3	$ 0.00400	$ 0.00180	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		
20	Residential R1 & R3 FPO	0.0040	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018		
21	C/I Sales G41 to G43	0.0040	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018		
22	C/I Sales G41 to G43 FPO	0.0040	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018		
23	C/I Sales G51 to G63	0.0040	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018		
24	C/I Sales G51 to G63 FPO	0.0040	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018		
25											
26	**WORKING CAPITAL REVENUE BILLED**										
27	Residential R1 & R3	$ 6,325	$ 1,534	$ 3,479	$ 2,768	$ 2,219	$ 2,234	$ 4,146	$ 3,682	**$ 20,063**	**$ 6,325**
28	Residential R1 & R3 FPO	1,467	353	1	0	1	-	1	603	**958**	**1,467**
29	C/I Sales G41 to G43	4,438	906	1,712	1,184	966	926	1,935	2,369	**9,998**	**4,438**
30	C/I Sales G41 to G43 FPO	554	100	4	(0)	-	(0)	-	139	**243**	**554**
31	C/I Sales G51 to G63	1,369	348	949	879	779	795	937	641	**5,327**	**1,369**
32	C/I Sales G51 to G63 FPO	166	34	-	-	-	-	-	34	**68**	**166**
33	**WORKING CAPITAL REVENUE BILLED**	**$ 14,319**	**$ 3,275**	**$ 6,145**	**$ 4,831**	**$ 3,965**	**$ 3,955**	**$ 7,019**	**$ 7,468**	**$ 36,658**	**$ 14,319**
34											
35	**BAD DEBT RATES**										
36	Residential R1 & R3	$ 0.00500	$ 0.00600	$ 0.0060	$ 0.0060	$ 0.0060	$ 0.0060	$ 0.0060	$ 0.0060		
37	Residential R1 & R3 FPO	0.0050	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060		
38	C/I Sales G41 to G43	0.0050	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060		
39	C/I Sales G41 to G43 FPO	0.0050	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060		
40	C/I Sales G51 to G63	0.0050	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060		
41	C/I Sales G51 to G63 FPO	0.0050	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060		
42											
43	**BAD DEBTS REVENUE BILLED**										
44	Residential R1 & R3	$ 7,907	$ 5,113	$ 11,597	$ 9,228	$ 7,398	$ 7,448	$ 13,819	$ 12,274	**$ 66,876**	$ 7,907
45	Residential R1 & R3 FPO	1,834	1,176	2	1	3	-	2	2,011	**3,195**	1,834
46	C/I Sales G41 to G43	5,548	3,020	5,708	3,947	3,219	3,086	6,451	7,897	**33,327**	5,548
47	C/I Sales G41 to G43 FPO	692	333	13	(0)	-	(0)	-	465	**812**	692
48	C/I Sales G51 to G63	1,711	1,159	3,164	2,929	2,596	2,650	3,124	2,137	**17,758**	1,711
49	C/I Sales G51 to G63 FPO	208	115	-	-	-	-	-	112	**227**	208
50	**BAD DEBTS REVENUE BILLED**	**$ 17,899**	**$ 10,916**	**$ 20,484**	**$ 16,104**	**$ 13,216**	**$ 13,184**	**$ 23,396**	**$ 24,895**	**$ 122,194**	**$ 17,899**

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
OFF PEAK COMMODITY COSTS AND THERMS
SCHEDULE 8

	FOR THE MONTH OF:		May-09		Jun-09		Jul-09		Aug-09		Sep-09		Oct-09		Total	
		Reference	Dollar	Volume Dth	Dollar	Volume Dth	Dollar	Volume Dth	Dollar	Volume Dth	Dollar	Volume Dth	Dollar	Volume Dth	Dollar	Volume Dth
1	TENNESSEE COMMODITY															
2	Total Supply	Sch 2B line 110														
3	Off System Sales	Sch 2B line 142														
4	Transportation	Sch 2B line 72														
5	Total Tennessee Commodity															
6																
7																
8	CITY GATE Distrigas FCS 064	Sch 2B line 77														
9	CITY GATE VPEM	Sch 2B line 78														
10	PNGTS															
11	Transportation PNGTS	Sch 2B line 82														
12																
13																
14	Hedge Gain/Loss	Sch 2B line 112														
15																
16																
17	BP/Northeast Gas Market	Sch 2B line 58														
18	Nexen	Sch 2B line 59														
19	Sempra	Sch 2B line 60														
20	ANE Union/Transgas Transporation	Sch 2B line 64														
21	SUBTOTAL CANADIAN COMM															
22																
23																
24	LNG VAPOR	Sch 2B line 122														
25	SUBTOTAL LNG															
26																
27																
28	PROPANE	Sch 2B line 128														
29																
30																
31	STORAGE WITHDRAWALS	Sch 2B line 117														
32	STORAGE INJECTIONS	Sch 2B line 118														
33																
34																
35	TAXES	Sch 2B line 130	$ -		$ -		$ -		$ -		$ -		$ -		$ -	-
36																
37	SUPPLIER CASHOUT	Sch 2B lines 132+138	$ 25,024		$ 36,723		$ 10,555		$ 13,400		$ 2,294		$ 10,423	0	$ 98,421	-
38																
39	CAPACITY MANAGED - CANADIAN	Sch 2B line 134	$ (105,360)		$ (62,239)		$ (139,030)		$ 76,791		$ (162,949)		$ (44,093)	0	$ (436,880)	-
40																
41	NON FIRM COSTS	Sch 2B line 144	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
42																
43	SUBTOTAL OTHER		$ (80,335)	0	$ (25,516)	0	$ (128,475)	0	$ 90,191	0	$ (160,654)	0	$ (33,669)	0	$ (338,459)	0
44																
45																
46	TOTAL COMMODITY COST		$ 2,923,500	344,021	$ 1,138,879	288,567	$ 1,019,134	241,320	$ 954,686	203,023	$ 855,214	292,057	$ 3,953,623	647,221	$ 10,845,036	2,016,209

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ENERGY NORTH NATURAL GAS, INC.

D/B/A NATIONAL GRID NH

MAY THROUGH OCTOBER 2009

MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
May 2009	05/01 - 05/31	3.25%	31	3.2500%
June 2009	06/01 - 06/30	3.25%	30	3.2500%
July 2009	07/01 - 07/31	3.25%	31	3.2500%
August 2009	08/01 - 08/31	3.25%	31	3.2500%
September 2009	09/01 - 09/30	3.25%	30	3.2500%
October 2009	10/01 - 10/31	3.25%	31	3.2500%

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
November 2008-October 2009

OCCUPANT DISALLOWANCE/CREDIT CALCULATION
SCHEDULE 10

1		T a
	Calculation of Threshold	
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1		< ᐊ
11	**Actual Annual Occupant Accounts closed from IT Report**	
1	a a T T	4 4
1	b	
14	a	4 1
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1	a a a	1
1		
1	**COG Data**	
	a	
1	a	1
	a	
4	**Calculation of Disallowance/Credit**	
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	b a a	
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ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
November 2008-October 2009
OCCUPANT DISALLOWANCE/CREDIT BACKUP
SCHEDULE 11

Occupant bills Calculation

1	T 1	1 4 41 4 4 1 T a	a	
	Nov-08			
4		1 1 4 11	1	1
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	a	1 4 14 4 1	1	1
4	Feb-09			
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	a	4	1	
		1 14 4 4 1 1	1 1	1
		1 1	1 41	
	a	4 1 1	1	
1	Mar-09			
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4				
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4		4 44	4	4
44	a	14 1		1
4	May-09			
4		1 1 11 1 1	4	1
4				
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	Jun-09			
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	Jul-09			
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4		1 4 4 4 1	4 4	
	a	1 1 1	1 4	
	Aug-09			
		11 1 1 1	1	14
	a	1 1 44 4	41 4	1
		1 4 41 4 1 4 1		1
1		1 4 1 1 14 41 4	4	4
	a	1 4 1 11 1	1	1
	Sep-09			
4		1 1 4		1
	a	1 4 4		
		1 4 1 1 4	1	4 4
		1 1 1 4 1	1 1	44
	a	4 4		4
	Oct-09			
1		11 4	41	14
	a	1 4 1 1 1	1	1
4		141 4		1
		1 1 4 4		1 4
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	Annual Nov 08-Oct 09			
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	a	4 4 4 4 4 1 4 4	44	4
1		1 4 4 1 1 1	1	
		4 4 4 4 41 4 1 4 1	4 1	4 4
	a	1 1 1 1 1 1	1	4

ENERGY NORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
November 2008-October 2009

OCCUPANT DISALLOWANCE/CREDIT BACKUP
SCHEDULE 11

Occupant bills Calculation

DETERMINATION OF COMMODITY PORTION OF GAS COSTS

4		a b a a T a
		Total Gas Cost From Annual Reconciliatoin
	a	1 1 4 444 1 4 4 4 1 1 4 4 1 4 4 1 1
1		144 1 1 41 1 411 1 4 1 4 1 14 4 1 1 1 4 1
1 1		1 4 1 4 4 4 1 4 1 1 4 1 1 1 1 1 4 1
1	a	4 41 41 41 41 41 4 4 1
1	b a	1 1 1 1 1 4 1 4 1 4 44 1 4 1 1 1 1 4 1 1 1 4 4 11
1 4		
1		1 1 1 1 1 4 1 4 1 4 44 1 4 1 1 1 1 4 1 1 1 4 4 11
1	a a	
1		
1	a	1 1 1 1
1		1
11		4 1
111	T a	11
11		
11		T a a T a a

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Off Peak 2010 Summer Cost of Gas Filing
Summary of Supply and Demand Forecast

NH Occupant Accounts
NH Advanced Consumption

Aging Frequency	Number of Accounts											
	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09
Less than 3 months	198	233	306	244	235	214	143	128	112	98	144	135
3 - 6 months	480	558	497	501	447	384	461	426	441	462	373	268
Greater than 6 months	337	365	371	403	426	424	384	327	258	213	152	81
Total	1,015	1,156	1,174	1,148	1,108	1,022	988	881	811	773	669	484
Monthly Differential		141	18	-26	-40	-86	-34	-107	-70	-38	-104	-185
Total Net Close		-220	-179	-160	-244	-240	-216	-246	-264	-228	-345	-432
Total Net Open		361	197	134	204	154	182	139	194	190	241	247

New Hampshire "Advanced Consumption" Summary
For the Month: November 2008

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	487	48.0%	13,117	10.6%
51 to 100 ccf	222	21.9%	16,137	13.1%
101 to 500 ccf	244	24.0%	49,134	39.7%
501 to 1,000 ccf	42	4.1%	29,765	24.1%
1,001 to 10,000 ccf	11	1.1%	15,464	12.5%
10,001 to 49,999 ccf	9	0.9%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**1,015**		**123,617**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	2	0.2%	$1	0.0%
$1 - $100	393	38.7%	$23,895	9.3%
$101 - $500	500	49.3%	$108,311	42.4%
$501 - $2,000	112	11.0%	$103,181	40.4%
$2,001 -	8	0.8%	$20,202	7.9%
$10,001 +				
Credit Balances				
Grand Total*	**1,015**		**$255,590**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	198	19.5%	$13,677	5.4%	$69
3 to 6 Months	480	47.3%	$65,988	25.8%	$137
* Greater than 6 Months	337	33.2%	$175,924	68.8%	$522
Total	**1,015**		**$255,590**		
**Greater than 6 Months and CCF > 500*	*53*		*$78,028*		$1,472

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	399	66			21	1	**22**	**40.0%**
51 to 100 ccf	190	20			12		**12**	**21.8%**
101 to 500 ccf	209	18			17		**17**	**30.9%**
501 to 1,000 ccf	36	5			1		**1**	**1.8%**
1,001 to 10,000 ccf	10					1	**1**	**1.8%**
10,001 to 49,999 ccf	7				2		**2**	**3.6%**
> 50,000 ccf								
CCF Unavailable*								
Total	**851**	**109**	**960**	**100.0%**	**53**	**2**	**55**	**100.0%**
% of Market Total	88.6%	11.4%			96.4%	3.6%		
% of Grand Total*	83.8%	10.7%			5.2%	0.2%		

12/15/2008
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2008Reports\BLMAdvConNov08.xls

00000094

New Hampshire "Advanced Consumption" Summary

For the Month: December 2008

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	421	36.4%	12,145	7.0%
51 to 100 ccf	257	22.2%	18,545	10.7%
101 to 500 ccf	402	34.8%	87,152	50.1%
501 to 1,000 ccf	52	4.5%	36,283	20.8%
1,001 to 10,000 ccf	15	1.3%	19,974	11.5%
10,001 to 49,999 ccf	9	0.8%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**1,156**		**174,099**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	1	0.1%		
$1 - $100	340	29.4%	$21,480	6.3%
$101 - $500	638	55.2%	$149,047	43.6%
$501 - $2,000	168	14.5%	$148,357	43.4%
$2,001 -	9	0.8%	$22,688	6.6%
$10,001 +				
Credit Balances				
Grand Total*	**1,156**		**$341,572**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	233	20.2%	$21,140	6.2%	$91
3 to 6 Months	558	48.3%	$116,685	34.2%	$209
* Greater than 6 Months	365	31.6%	$203,748	59.6%	$558
Total	**1,156**		**$341,572**		
**Greater than 6 Months and CCF > 500*	*59*		*$88,397*		$1,498

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	332	69			18	2	**20**	**28.2%**
51 to 100 ccf	217	23			17		**17**	**23.9%**
101 to 500 ccf	356	22			23	1	**24**	**33.8%**
501 to 1,000 ccf	41	5			6		**6**	**8.5%**
1,001 to 10,000 ccf	12	1			1	1	**2**	**2.8%**
10,001 to 49,999 ccf	6	1			2		**2**	**2.8%**
> 50,000 ccf								
CCF Unavailable*								
Total	**964**	**121**	**1,085**	**100.0%**	**67**	**4**	**71**	**100.0%**
% of Market Total	88.8%	11.2%			94.4%	5.6%		
% of Grand Total*	**83.4%**	**10.5%**			**5.8%**	**0.3%**		

00000095

1/8/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2008Reports\BLMAdvConDec08.xls

New Hampshire "Advanced Consumption" Summary
For the Month: January 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	322	27.4%	9,527	3.9%
51 to 100 ccf	221	18.8%	16,579	6.7%
101 to 500 ccf	497	42.3%	117,568	47.7%
501 to 1,000 ccf	89	7.6%	59,981	24.3%
1,001 to 10,000 ccf	33	2.8%	42,706	17.3%
10,001 to 49,999 ccf	12	1.0%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**1,174**		**246,361**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	5	0.4%	$0	0.0%
$1 - $100	255	21.7%	$16,082	3.6%
$101 - $500	633	53.9%	$158,688	35.1%
$501 - $2,000	266	22.7%	$238,647	52.8%
$2,001 -	15	1.3%	$38,400	8.5%
$10,001 +				
Credit Balances				
Grand Total*	**1,174**		**$451,818**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	306	26.1%	$45,044	10.0%	$147
3 to 6 Months	497	42.3%	$166,492	36.8%	$335
* Greater than 6 Months	371	31.6%	$240,282	53.2%	$648
Total	**1,174**		**$451,818**		
**Greater than 6 Months and CCF > 500*	*87*		*$128,303*		$1,475

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	237	71			10	4	**14**	**18.9%**
51 to 100 ccf	186	26			8	1	**9**	**12.2%**
101 to 500 ccf	438	28			27	4	**31**	**41.9%**
501 to 1,000 ccf	72	5			12		**12**	**16.2%**
1,001 to 10,000 ccf	24	2			7		**7**	**9.5%**
10,001 to 49,999 ccf	11				1		**1**	**1.4%**
> 50,000 ccf								
CCF Unavailable*								
Total	**968**	**132**	**1,100**	**100.0%**	**65**	**9**	**74**	**100.0%**
% of Market Total	88.0%	12.0%			87.8%	12.2%		
% of Grand Total*	**82.5%**	**11.2%**			**5.5%**	**0.8%**		

2/9/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConJan09.xls

New Hampshire "Advanced Consumption" Summary
For the Month: February 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	280	24.4%	8,232	2.8%
51 to 100 ccf	194	16.9%	14,167	4.8%
101 to 500 ccf	493	42.9%	123,049	41.8%
501 to 1,000 ccf	118	10.3%	80,462	27.3%
1,001 to 10,000 ccf	49	4.3%	68,792	23.3%
10,001 to 49,999 ccf	14	1.2%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**1,148**		**294,702**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	3	0.3%	$0	0.0%
$1 - $100	231	20.1%	$14,223	2.7%
$101 - $500	570	49.7%	$146,035	27.9%
$501 - $2,000	319	27.8%	$296,021	56.5%
$2,001 -	25	2.2%	$67,237	12.8%
$10,001 +				
Credit Balances				
Grand Total*	**1,148**		**$523,518**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	244	21.3%	$36,538	7.0%	$150
3 to 6 Months	501	43.6%	$192,223	36.7%	$384
* Greater than 6 Months	403	35.1%	$294,756	56.3%	$731
Total	**1,148**		**$523,518**		
**Greater than 6 Months and CCF > 500*	*119*		*$176,764*		$1,485

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	215	52			8	5	**13**	**16.9%**
51 to 100 ccf	155	26			13		**13**	**16.9%**
101 to 500 ccf	437	28			28		**28**	**36.4%**
501 to 1,000 ccf	102	6			10		**10**	**13.0%**
1,001 to 10,000 ccf	36	2			11		**11**	**14.3%**
10,001 to 49,999 ccf	12				1	1	**2**	**2.6%**
> 50,000 ccf								
CCF Unavailable*								
Total	**957**	**114**	**1,071**	**100.0%**	**71**	**6**	**77**	**100.0%**
% of Market Total	89.4%	10.6%			92.2%	7.8%		
% of Grand Total*	83.4%	9.9%			6.2%	0.5%		

3/11/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConFeb09.xls

00000097

New Hampshire "Advanced Consumption" Summary
For the Month: March 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	274	24.7%	7,933	2.5%
51 to 100 ccf	183	16.5%	13,507	4.2%
101 to 500 ccf	428	38.6%	109,441	34.4%
501 to 1,000 ccf	143	12.9%	96,448	30.3%
1,001 to 10,000 ccf	64	5.8%	90,487	28.5%
10,001 to 49,999 ccf	16	1.4%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	1,108		317,816	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	1	0.1%	$1	0.0%
$1 - $100	238	21.5%	$13,809	2.5%
$101 - $500	484	43.7%	$120,489	21.7%
$501 - $2,000	349	31.5%	$328,625	59.2%
$2,001 -	36	3.2%	$92,462	16.6%
$10,001 +				
Credit Balances				
Grand Total*	1,108		$555,386	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	235	21.2%	$23,526	4.2%	$100
3 to 6 Months	447	40.3%	$187,099	33.7%	$419
* Greater than 6 Months	426	38.4%	$344,761	62.1%	$809
Total	1,108		$555,386		
Greater than 6 Months and CCF > 500	*152*		*$232,497*		$1,530

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	208	50			12	4	16	21.3%
51 to 100 ccf	141	28			13	1	14	18.7%
101 to 500 ccf	374	28			26		26	34.7%
501 to 1,000 ccf	130	6			7		7	9.3%
1,001 to 10,000 ccf	51	3			10		10	13.3%
10,001 to 49,999 ccf	14				1	1	2	2.7%
> 50,000 ccf								
CCF Unavailable*								
Total	918	115	1,033	100.0%	69	6	75	100.0%
% of Market Total	88.9%	11.1%			92.0%	8.0%		
% of Grand Total*	82.9%	10.4%			6.2%	0.5%		

4/6/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConMar09.xls

New Hampshire "Advanced Consumption" Summary
For the Month: April 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	289	28.3%	7,995	2.9%
51 to 100 ccf	148	14.5%	10,849	4.0%
101 to 500 ccf	371	36.3%	93,393	34.1%
501 to 1,000 ccf	119	11.6%	80,726	29.5%
1,001 to 10,000 ccf	55	5.4%	80,636	29.5%
10,001 to 49,999 ccf	40	3.9%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**1,022**		**273,599**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	7	0.7%	$2	0.0%
$1 - $100	261	25.5%	$13,527	2.8%
$101 - $500	433	42.4%	$106,270	22.1%
$501 - $2,000	284	27.8%	$265,941	55.3%
$2,001 -	37	3.6%	$95,273	19.8%
$10,001 +				
Credit Balances				
Grand Total*	**1,022**		**$481,013**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	214	20.9%	$15,173	3.2%	$71
3 to 6 Months	384	37.6%	$132,984	27.6%	$346
* Greater than 6 Months	424	41.5%	$332,857	69.2%	$785
Total	**1,022**		**$481,013**		
**Greater than 6 Months and CCF > 500*	*141*		*$219,526*		$1,557

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	233	42			11	3	**14**	**19.2%**
51 to 100 ccf	113	21			12	2	**14**	**19.2%**
101 to 500 ccf	318	31			22		**22**	**30.1%**
501 to 1,000 ccf	110	3			6		**6**	**8.2%**
1,001 to 10,000 ccf	45	2			8		**8**	**11.0%**
10,001 to 49,999 ccf	30	1			7	2	**9**	**12.3%**
> 50,000 ccf								
CCF Unavailable*								
Total	**849**	**100**	**949**	**100.0%**	**66**	**7**	**73**	**100.0%**
% of Market Total	89.5%	10.5%			90.4%	9.6%		
% of Grand Total*	**83.1%**	**9.8%**			**6.5%**	**0.7%**		

5/11/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConApr09.xls

6600000099

New Hampshire "Advanced Consumption" Summary
For the Month: May 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	339	34.3%	8,894	4.1%
51 to 100 ccf	157	15.9%	11,310	5.2%
101 to 500 ccf	321	32.5%	77,508	35.7%
501 to 1,000 ccf	102	10.3%	67,856	31.2%
1,001 to 10,000 ccf	35	3.5%	51,650	23.8%
10,001 to 49,999 ccf	34	3.4%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**988**		**217,218**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	5	0.5%	$2	0.0%
$1 - $100	311	31.5%	$16,095	4.1%
$101 - $500	423	42.8%	$101,829	26.1%
$501 - $2,000	226	22.9%	$211,296	54.1%
$2,001 -	23	2.3%	$61,542	15.7%
$10,001 +				
Credit Balances				
Grand Total*	**988**		**$390,764**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	143	14.5%	$5,992	1.5%	$42
3 to 6 Months	461	46.7%	$105,299	26.9%	$228
* Greater than 6 Months	384	38.9%	$279,473	71.5%	$728
Total	**988**		**$390,764**		
**Greater than 6 Months and CCF > 500*	*113*		*$171,463*		$1,517

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	276	46			15	2	**17**	**27.9%**
51 to 100 ccf	124	21			12		**12**	**19.7%**
101 to 500 ccf	277	25			17	2	**19**	**31.1%**
501 to 1,000 ccf	94	4			4		**4**	**6.6%**
1,001 to 10,000 ccf	31	2			2		**2**	**3.3%**
10,001 to 49,999 ccf	26	1			7		**7**	**11.5%**
> 50,000 ccf								
CCF Unavailable*								
Total	**828**	**99**	**927**	**100.0%**	**57**	**4**	**61**	**100.0%**
% of Market Total	89.3%	10.7%			93.4%	6.6%		
% of Grand Total*	83.8%	10.0%			5.8%	0.4%		

6/5/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConMay09.xls

00000100

New Hampshire "Advanced Consumption" Summary
For the Month: June 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	391	44.4%	10,310	6.6%
51 to 100 ccf	131	14.9%	9,490	6.0%
101 to 500 ccf	247	28.0%	57,979	37.0%
501 to 1,000 ccf	64	7.3%	43,978	28.0%
1,001 to 10,000 ccf	23	2.6%	35,114	22.4%
10,001 to 49,999 ccf	25	2.8%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**881**		**156,871**	

** "Old" occupant accounts data record doesn't contain consumption

$

Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	2	0.2%		
$1 - $100	362	41.1%	$19,534	6.7%
$101 - $500	351	39.8%	$85,711	29.4%
$501 - $2,000	148	16.8%	$137,928	47.4%
$2,001 -	18	2.0%	$48,017	16.5%
$10,001 +				
Credit Balances				
Grand Total*	**881**		**$291,191**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	128	14.5%	$4,390	1.5%	$34
3 to 6 Months	426	48.4%	$68,564	23.5%	$161
* Greater than 6 Months	327	37.1%	$218,237	74.9%	$667
Total	**881**		**$291,191**		
**Greater than 6 Months and CCF > 500*	*82*		*$125,246*		$1,527

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	327	44			18	2	**20**	**38.5%**
51 to 100 ccf	99	21			11		**11**	**21.2%**
101 to 500 ccf	215	21			10	1	**11**	**21.2%**
501 to 1,000 ccf	60	4						
1,001 to 10,000 ccf	21	1			1		**1**	**1.9%**
10,001 to 49,999 ccf	16				9		**9**	**17.3%**
> 50,000 ccf								
CCF Unavailable*								
Total	**738**	**91**	**829**	**100.0%**	**49**	**3**	**52**	**100.0%**
% of Market Total	89.0%	11.0%			94.2%	5.8%		
% of Grand Total*	**83.8%**	**10.3%**			**5.6%**	**0.3%**		

7/9/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConJune09.xls

00000101

New Hampshire "Advanced Consumption" Summary
For the Month: July 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	437	53.9%	11,364	10.8%
51 to 100 ccf	147	18.1%	10,399	9.9%
101 to 500 ccf	155	19.1%	34,530	32.8%
501 to 1,000 ccf	30	3.7%	21,237	20.2%
1,001 to 10,000 ccf	18	2.2%	27,777	26.4%
10,001 to 49,999 ccf	24	3.0%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**811**		**105,307**	

** "Old" occupant accounts data record doesn't contain consumption

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Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	9	1.1%		
$1 - $100	395	48.7%	$22,422	10.8%
$101 - $500	312	38.5%	$69,098	33.3%
$501 - $2,000	81	10.0%	$77,341	37.3%
$2,001 -	14	1.7%	$38,338	18.5%
$10,001 +				
Credit Balances				
Grand Total*	**811**		**$207,199**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	112	13.8%	$4,558	2.2%	$41
3 to 6 Months	441	54.4%	$45,813	22.1%	$104
* Greater than 6 Months	258	31.8%	$156,829	75.7%	$608
Total	**811**		**$207,199**		
**Greater than 6 Months and CCF > 500*	*47*		*$79,627*		$1,694

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	361	45			29	2	**31**	**50.0%**
51 to 100 ccf	118	17			12		**12**	**19.4%**
101 to 500 ccf	135	15			5		**5**	**8.1%**
501 to 1,000 ccf	27	2				1	**1**	**1.6%**
1,001 to 10,000 ccf	16	1			1		**1**	**1.6%**
10,001 to 49,999 ccf	11	1			12		**12**	**19.4%**
> 50,000 ccf								
CCF Unavailable*								
Total	**668**	**81**	**749**	**100.0%**	**59**	**3**	**62**	**100.0%**
% of Market Total	89.2%	10.8%			95.2%	4.8%		
% of Grand Total*	**82.4%**	**10.0%**			**7.3%**	**0.4%**		

00000102

08/10/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
H:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConJul09.xls

New Hampshire "Advanced Consumption" Summary

For the Month: August 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	476	61.6%	12,351	18.6%
51 to 100 ccf	149	19.3%	10,649	16.0%
101 to 500 ccf	85	11.0%	17,110	25.8%
501 to 1,000 ccf	15	1.9%	10,068	15.2%
1,001 to 10,000 ccf	11	1.4%	16,223	24.4%
10,001 to 49,999 ccf	37	4.8%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	773		66,401	

** "Old" occupant accounts data record doesn't contain consumption

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Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	9	1.2%	$1	0.0%
$1 - $100	431	55.8%	$24,601	17.6%
$101 - $500	284	36.7%	$56,746	40.6%
$501 - $2,000	42	5.4%	$40,330	28.9%
$2,001 -	7	0.9%	$17,934	12.8%
$10,001 +				
Credit Balances				
Grand Total*	773		$139,612	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	98	12.7%	$2,590	1.9%	$26
3 to 6 Months	462	59.8%	$41,391	29.6%	$90
* Greater than 6 Months	213	27.6%	$95,630	68.5%	$449
Total	773		$139,612		
Greater than 6 Months and CCF > 500	*25*		*$40,530*		$1,621

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	401	48			25	2	27	62.8%
51 to 100 ccf	127	16			6		6	14.0%
101 to 500 ccf	72	12			1		1	2.3%
501 to 1,000 ccf	14	1						
1,001 to 10,000 ccf	9				1	1	2	4.7%
10,001 to 49,999 ccf	28	2			7		7	16.3%
> 50,000 ccf								
CCF Unavailable*								
Total	651	79	730	100.0%	40	3	43	100.0%
% of Market Total	89.2%	10.8%			93.0%	7.0%		
% of Grand Total*	84.2%	10.2%			5.2%	0.4%		

03/10/2010
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
G:\RATES\EnergyNorth\Occupant Disallowance Credit\Occupant Reports 2008-2009\BLMAdvConAug09.xls

New Hampshire "Advanced Consumption" Summary
For the Month: September 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	369	55.2%	8,902	20.8%
51 to 100 ccf	116	17.3%	7,918	18.5%
101 to 500 ccf	56	8.4%	10,876	25.5%
501 to 1,000 ccf	8	1.2%	5,387	12.6%
1,001 to 10,000 ccf	7	1.0%	9,616	22.5%
10,001 to 49,999 ccf	113	16.9%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**669**		**42,699**	

** "Old" occupant accounts data record doesn't contain consumption

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Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	18	2.7%	$2	0.0%
$1 - $100	429	64.1%	$20,959	22.3%
$101 - $500	192	28.7%	$37,289	39.6%
$501 - $2,000	25	3.7%	$23,593	25.1%
$2,001 -	5	0.7%	$12,330	13.1%
$10,001 +				
Credit Balances				
Grand Total*	**669**		**$94,173**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	144	21.5%	$2,400	2.5%	$17
3 to 6 Months	373	55.8%	$28,653	30.4%	$77
* Greater than 6 Months	152	22.7%	$63,120	67.0%	$415
Total	**669**		**$94,173**		
**Greater than 6 Months and CCF > 500*	*15*		*$25,581*		$1,705

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	330	29			9	1	10	33.3%
51 to 100 ccf	97	16			3		3	10.0%
101 to 500 ccf	49	6			1		1	3.3%
501 to 1,000 ccf	8							
1,001 to 10,000 ccf	7							
10,001 to 49,999 ccf	92	5			13	3	16	53.3%
> 50,000 ccf								
CCF Unavailable*								
Total	**583**	**56**	**639**	**100.0%**	**26**	**4**	**30**	**100.0%**
% of Market Total	91.2%	8.8%			86.7%	13.3%		
% of Grand Total*	**87.1%**	**8.4%**			**3.9%**	**0.6%**		

00000104

10/05/2009
Data Source:NE Occupant "System Generated" Query named: OCCUPANT_WS_ENT_Q (J. Clifford)
F:\SS_DATA\AdvancedConsumption\2009Reports\BLMAdvConSep09.xls

New Hampshire "Advanced Consumption" Summary
For the Month: October 2009

II. Overall Statistics by Frequency

CCF

Adv Consumption Frequency	Number of Accts	% of Grand Total	Total CCF (Unconfirmed)	% of Total
13 to 50 ccf	335	69.2%	8,188	36.5%
51 to 100 ccf	79	16.3%	5,522	24.6%
101 to 500 ccf	30	6.2%	5,414	24.1%
501 to 1,000 ccf	2	0.4%	1,411	6.3%
1,001 to 10,000 ccf	1	0.2%	1,918	8.5%
10,001 to 49,999 ccf	37	7.6%	-	
> 50,000 ccf				
CCF Unavailable*				
Grand Total*	**484**		**22,453**	

** "Old" occupant accounts data record doesn't contain consumption

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Adv. Consumption Acct Balance	Number of Accts	Number of Accts	Total $ (Unconfirmed)	% of Total
$0	2	0.4%	$1	0.0%
$1 - $100	358	74.0%	$17,986	36.0%
$101 - $500	113	23.3%	$19,943	40.0%
$501 - $2,000	10	2.1%	$8,702	17.4%
$2,001 -	1	0.2%	$3,277	6.6%
$10,001 +				
Credit Balances				
Grand Total*	**484**		**$49,909**	

Aging Frequency	Number of Accts	% of Total	Total $ (Unconfirmed)	% of Total	Average Acct Balance
Less than 3 Months	135	27.9%	$4,467	9.0%	$33
3 to 6 Months	268	55.4%	$19,440	39.0%	$73
* Greater than 6 Months	81	16.7%	$26,002	52.1%	$321
Total	**484**		**$49,909**		
**Greater than 6 Months and CCF > 500*	3		*$6,102*		$2,034

II. Statistics by Market & Usage

	Number of Accounts							
	Residential				Non-Residential			
Adv Consumption Frequency	Heating	Non-Heating	Residential-Total	% of Market Total	Heating	Non-Heating	Non-Residential Total	% of Market Total
13 to 50 ccf	293	27			13	2	**15**	**57.7%**
51 to 100 ccf	69	8			2		**2**	**7.7%**
101 to 500 ccf	24	5				1	**1**	**3.8%**
501 to 1,000 ccf	2							
1,001 to 10,000 ccf	1							
10,001 to 49,999 ccf	29				7	1	**8**	**30.8%**
> 50,000 ccf								
CCF Unavailable*								
Total	**418**	**40**	**458**	**100.0%**	**22**	**4**	**26**	**100.0%**
% of Market Total	91.3%	8.7%			84.6%	15.4%		
% of Grand Total*	**86.4%**	**8.3%**			**4.5%**	**0.8%**		

00000105