REDACTED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc.
d/b/a Liberty Utilities

Winter 2012-13 Cost of Gas

DG 12-______

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

August 31, 2012

TABLE OF CONTENTS

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

A. My name is Ann E. Leary. I am the Manager of Gas Pricing for National Grid Corporate Service LLC. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. As an employee of National Grid, please explain why you are testifying today on behalf of EnergyNorth Natural Gas, Inc?

A. In accordance with Amended and Restated Transition Services Agreement between National Grid USA and EnergyNorth Natural Gas, Inc. (the "Company"), employees of National Grid or its affiliated companies are providing certain services to the Company, including assistance with matters relating to Cost of Gas proceedings.

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

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

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

A. As the Manager Pricing, I am responsible for preparing and submitting various regulatory filings with the Massachusetts Department of Public Utilities on behalf of National Grid local gas distribution companies. Prior to the sale of EnergyNorth, I prepared and submitted regulatory filings to the New Hampshire Public Utilities Commission (the "Commission") on behalf of EnergyNorth. These filings include Cost of Gas ("COG") filings, Local Distribution Adjustment Charge ("LDAC") filings and reconciliations, energy conservation, performance-based revenue calculations, lost-base revenues, and exogenous cost filings.

Q. Please summarize your educational background.

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

Q. Have you previously testified in regulatory proceedings?

A. I have testified in a number of regulatory proceedings before the Commission and the Massachusetts Department of 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 2012/13 Winter (Peak) Period and the Company's proposed 2012/13 Local Distribution Adjustment Factor both effective beginning November 1, 2012.

COST OF GAS FACTOR

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

A. The Company proposes a firm sales cost of gas rate of $0.6719 per therm for residential customers, $0.6736 per therm for commercial/industrial high winter use customers and $0.6671 per therm for commercial/industrial low winter use customers as shown on Proposed Third Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0002 per therm as shown on Proposed First Revised Page 89.

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

A. Proposed First Revised Page 86 and Proposed Third Revised Page 87 contain the calculation of the 2012/13 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 87, the proposed 2012/13 Average Cost of Gas of $0.6719 per therm is derived by adding the Direct Cost of Gas Rate of $0.6279 per therm to the Indirect Cost of Gas Rate of $0.0440 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $48,820,141. The estimated Indirect Cost of Gas, also derived on

Page 86 and repeated on Page 87, is $3,420,439. The Direct Cost of Gas Rate of $0.6279 and the Indirect Cost of Gas Rate of $0.0440 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 77,755,617 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 86, total $295,808. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $48,524,333 to determine the Total Anticipated Direct Cost of Gas of $48,820,141.

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

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

1.	Purchased Gas Demand Costs	$9,446,057
2.	Purchased Gas Commodity Costs	$26,630,667
3.	Storage Demand and Capacity Costs	$1,092,898
4.	Storage Commodity Costs	$9,121,704
5.	Produced Gas Cost	$291,366
6.	Hedge Contract Loss/(Savings)	$1,941,641
	Total	$48,524,333

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

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

1.	Prior Period Under Collection	$1,606,569
2.	Interest	73,865
3.	Broker Revenues	(396,197)
4.	Fuel Financing	109,724
5.	Transportation COG Revenue	(8,224)
6.	Interruptible Sales Margin	0
7.	Capacity Release Margin	(1,130,619)
8.	Fixed Price Administrative Cost	40,691
	Total Adjustments	$295,808

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

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in DG 11-192 for the 2011/12 Winter Period?

A. The average cost of gas rate proposed in this filing is $0.1207 per therm lower than the initial rate of $0.7926 approved by the Commission in Order No. 25,286 dated October 31, 2011 in DG 11-192. This decrease in the rate reflects a decrease in the total cost of gas of approximately $13.3 million or 20% (a $13.1 million decrease in total direct gas costs and a $0.2 million decrease in indirect gas costs). The $13.1 million decrease in the total direct cost of gas is a result of a $8.8 million decrease in commodity costs, a $2.4 million decrease in demand costs and a $1.9 million decrease in adjustments.

The $8.8 million decrease in commodity costs is due to a $9.0 million decrease in pipeline commodity costs offset by a $0.2 million increase in supplemental costs (underground storage, LNG, and propane). The $9.0 million decrease in pipeline costs is due to a projected decrease in commodity price of $4.3 million and a projected decrease of $4.7 million resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are projected to be approximately $.0408/therm lower than last year, resulting in a $4.3 million decrease, while pipeline throughput is projected to be down by 8.4 million therms, resulting in a decrease in commodity costs of $4.7 million. The $1.9 million decrease in adjustments reflects a $2.1 million decrease in Prior Period Under Collection, $0.7 million decrease in interruptible sales margin and a $1.0 increase in Broker Revenues.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2011/12 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0002 per therm. The rate approved in DG 11-192 was $0.0000. This increase is largely due to the increase in the net amount to be collected from Transportation customers to the 2011-12 period.

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. No, the Company used for pressure support purposes 9.9% based on the marginal cost study used for the rate design approved in the Settlement Agreement in DG 10-017, that was applied to the Peak 2011/12 Cost of Gas filing.

Q. What was the actual weighted average firm sales cost of gas rate for the 2011/12 winter period?

A. The weighted average cost of gas rate was approximately $0.7309 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2011 through April 2012 to the monthly therm usage of a typical residential heating customer using 1,250 therms per year, or 932 therms for the six winter period months, for heat, hot water and cooking.

<u>PRIOR PERIOD UNDER COLLECTION</u>

Q. Please explain the Prior Period Under Collection of $1,719,376.

A. The Prior Period Under Collection is detailed in the 2011/12 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $1,719,376 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2012, including Peak Period costs recovered in May 2012 based on billings for April consumption. The under collection is primarily due to lower sales and sendout throughput during March and April 2012 due to warmer than normal weather. The Company's April trigger filing was based on normal weather.

<u>FIXED PRICE OPTION</u>

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

A. Yes, in Order No. 24,515 in docket DG 05-127, dated September 16, 2005, the Commission approved an amendment to the Fixed Price Option Program ("FPO"). In accordance with the approved changes to the FPO, the FPO rates are set at $0.02 per therm higher than the initial proposed COG. Proposed First Revised Page 88 contains the FPO rates for the 2012/13 Winter period, which are $0.6919 per therm for residential customers, $0.6871 per therm for commercial/industrial low winter use customers, and $0.6936 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2011/12 winter period of $0.8126 per therm for residential customers, $0.8111 per therm for commercial/industrial low winter use customers, and $0.8129 per therm for commercial/industrial high winter use customers. This represents a $0.1207 per therm, or 14.9%, decrease in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a decrease of approximately $153 or 13.2% compared to last winter. The bill impact reflects the implementation of the decrease approved in DG 12-128 effective July 1, 2012 relating to the cast iron/bare steel main replacement program. The estimated winter period bill for a typical residential heating customer opting for the FPO would be approximately $19 or 1.9% higher than the bill under the proposed cost of rates assuming that the COG is not revised prior to final approval by the Commission and also assuming no monthly adjustments to the COG rate during the course of the winter. Tab 23 contains the historical results of the FPO program as required by Order No. 24,515 issued on September 16, 2005 in DG 05-127.

HEDGED SUPPLIES

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

A. Yes, it has. As shown in Tab 7, Schedule 7, Page 2, the Company thus far has hedged 2,010,000 Dekatherms (20.1 million therms) at a weighted average fixed price of $4.3890 per Dekatherm. The hedged price reflects the higher cost of gas during the period that the hedged volumes were locked in. The Company shows in Tab 7, Schedule 7, Page 3, that the remaining 920,000 Dekatherms will be hedged at an estimated price of $3.4250 per Dekatherm based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 2,930,000 Dekatherms at a cost of $11,972,792 or approximately $4.0863 per Dth.

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

A. The Company has eighteen contracts that hedge the price of gas supplies for the 2012/13 Winter Period with prices ranging from $2.78 to $5.5300 per Dekatherms. The contracts date as far back as June 10, 2011 and as recently as July 20, 2012. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

LOCAL DISTRIBUTION ADJUSTMENT CHARGE

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

A. The Company is submitting for approval an LDAC of $0.0258 for the residential non heating class and residential heating class, and $0.0187 for the commercial/industrial bundled sales classes. The surcharges that are billed under the LDAC are the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Low Income Assistance Program charge, and the Temporary Rate Reconciliation Amount per DG 10-017 as approved per (1) Order No. 24,109 in DG 02-106, Energy Efficiency for Gas Utilities, (2) Order No. 24,636 in DG 06-032, Energy Efficiency for Gas Utilities, (3) Order No. 24,508 in DG 05-076, and (4) Order No. 25,202 in DG 10-017.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2013 that will be filed with the Commission on September 17, 2012. In the calculation of the Energy Efficiency Factor, the Company has also included the projected prior period over recovery of the Company's Residential and Commercial energy efficiency programs as of October 2012. The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs during the period January–December 2011 that were filed with the Commission in DE 10-188 on June 21, 2012.

The incentive calculations that are included in this LDAC filing are based on Exhibit C which is provided in Tab 19, Energy Efficiency, page 5.

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

A. The proposed RLIAP charge is $0.0073. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this program. For the 2012/13 Winter Period the Company is providing a 60% base rate discount, consistent with the settlement agreement approved by the Commission in Order No. 24,669 issued on September 22, 2006 in DG 06-120. The current RLIAP factor is designed to recover $1,156,572, of which $1,495,954 is for the revenue shortfall resulting from 5,485 customers receiving a 60% discount off their base rates, $ 8,600 is for estimated administrative costs, and ($347,982) is for the prior year reconciling adjustment.

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

A. Yes, the Company included in Tab 24 the short term debt limit for fuel and non fuel purposes for the 2012-13 period. As shown, the short term limit for fuel inventory financing for the period November 1, 2011 through October 31, 2012 is calculated to be $15,672,174 and the limit for non-fuel purposes is calculated to be $45,937,039.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 91)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism as well as the third party recoveries are presented in the Environmental Cost Summary included in Tab 20 of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Leone in her pre-filed testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Tab 20. The Summary included in Tab 20, pages 1 – 8, shows the remediation cost pools for the Concord, Manchester, Nashua, Dover, Laconia and Keene sites and a General Pool for costs that cannot be directly assigned to a specific site. The filing also includes amounts recovered from insurance companies shown in the section labeled "Cash Recoveries" on the Environmental Cost Summary, pages 9 - 12. These cash recoveries from insurance companies are listed under the headings for the Concord, Laconia, Manchester, Nashua, Dover, and Keene sites. While the recoveries are displayed on the summary by site, they are not exclusive to a particular site. Because the recoveries are often the result of general settlement agreements covering more than one site, there is no basis to determine how much of the settlement amount is associated with a particular site. Page 13 provides the total remediation and recovery costs and collections by year and in total.

In total, the Company has incurred environmental remediation costs of $33,437,414, litigation costs of $9,466,750, and obtained third party cash recoveries of $27,913,628, for a net expense of $14,990,536. To date, the Company has collected $13,237,827 from its Environmental Surcharge factor and base rates.

The 2011-2012 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #12)	$81,238
Concord (Pool #9)	$257,528
Laconia (Pool #11)	$269,281
Manchester (Pool #12)	$442,298
Nashua (Pool #11)	$396,411
Keene (Pool#9)	$488
General (Pool #10)	$78,967
Total Remediation	$1,526,211
Litigation Recovery	0
Litigation Costs	0
Total 2011-2012	$1,526,211

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2011-2012 costs that the Company is submitting. Consistent with past practice, the Company met with the Commission staff earlier this year to update them on the status of environmental matters. Ms. Leone's testimony describes the Company's activities with regard to all six sites. The Company is prepared to provide additional testimony and exhibits, if necessary, to further support recovery of these amounts after the Commission Staff has completed its review of these costs.

Q. In DG 11-192, the Company indicated that approximately $78,000 of environmental costs had been embedded in the approved base rate tariffs. How did the Company reflect those revenues in its calculation of its RAC?

A. The Company has modified its Environmental Cost Summary Schedules in Tab 20 to include the base rate recoveries for the period June 2010 through October 2012. The Company determined these recoveries by multiplying the base rate component associated with the environmental costs by the monthly volumetric throughput during the period June 2010 through October 2012. The Company calculated the environmental rate that was embedded in the base rates by simply dividing the total embedded cost of $78,892 by the 2008-2009 test year normalized throughput level of 148,771,890 therms to derive a factor of $0.0005/therm. Finally, the Company allocated these environmental base rate revenues to those specific pools with outstanding balances.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2012 and ending October 31, 2013 is $0.0011 per therm. This factor will recover a total of $256,547 in amortized remediation costs less the $78,892 in base rate collections for a net of $177,655. The costs submitted for recovery are presented in the Environmental Cost Summary included in Tab 20 of this filing.

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

A. No, the Company has not provided any service under the classification over the past year and therefore has not earned any margins to credit back to sales customers.

Q. Is the Company proposing to include any Temporary Rate Reconciliation Adjustment approved in Order 25,217 in DG 11-046 relating to the reconciliation for temporary rates from the Company's last base rate case, DG 10-017?

A. In DG 11-192, the Commission approved recovery on the Temporary Rate Case reconciliation (including rate case expense) adjustment factor of $0.0116 per therm to be assessed to customers during the period November 2011 through October 2012. This factor was developed by dividing the total Temporary Rate Reconciliation Adjustment of $1,899,706 by the projected annual normal throughput of 163,588,592. However, due to weather that was approximately 20% warmer than normal, the Company did not realize the throughput it had projected and as a result did not collect the entire $1,899,706 associated with the Temporary Rate Reconciliation Adjustment. Based on actual collections through July 2012 and projected collections from August 2012 through October 2012, the Company projects that it will collect only $1,468,933. As a result, the

Company is proposing to recover the residual amount of $430,773 ($1,899,706-$1,468,933) from all customers during the period November 2012 through October 2013.

Q. Has the Company also updated its Company Allowance percentage for the period November 2012-October 2013 in accordance with Section 8.1 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 the Company has recalculated its Company Allowance for the period November 2011 – October 2012. The Company calculated the Company Allowance of 1.6% based on sendout and throughput data for the twelve month period ending June 2012. This recalculated Company Allowance is proposed to be applied to all supplier deliveries beginning in November 2012.

CUSTOMER BILL IMPACTS

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

A. The bill impact analysis is presented in Tab 8, Schedule 8 of this filing. Please note that these bill impacts include the base distribution rates approved in Order No. 25,378 in Docket DG 12-128 relating to the cast iron/bare steel main replacement program. The total bill impact for a typical residential heating customer is an decrease of approximately $96, or -8.8%, of which $95, or -14.0%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2011/12 winter season, and a decrease of

$0.3, or -0.1%, resulting from the base rate adjustment in DG 12-128. The total bill impact for a typical commercial/industrial G-41 customer is a decrease of approximately $129, or -7.4%, of which $128, or -12.3 %, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2011/12 winter season and a decrease of $0.5, or -0.1%, resulting from the base rate adjustment in DG 12-128. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

OTHER TARIFF CHANGES

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

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

Q. Please describe the changes to Page 155.

A. In Proposed First Revised Page 155, the Company is updating the Peaking Demand Charge from $18.96 per MMBtu of Peak MDQ to $18.62 per MMBtu of Peak MDQ, a $0.34 decrease and its Supplier Balancing Charges from $0.22 per MMBtu to $0.19 per MMBtu.

This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions Proposed First Revised Page 155, Attachment B – Peaking Demand Charge.

Q. Please describe the changes to Page 156.

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

Q. Does this conclude your testimony?

A. Yes, it does.