STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

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

Winter 2010-11 Cost of Gas

DG 10-______

Prefiled Testimony of Ann E. Leary

August 31, 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.

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

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

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

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

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

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

Q. Please summarize your educational background.

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

Q. Have you previously testified in regulatory proceedings?

A. I have testified in a number of regulatory proceedings before the Commission and the Massachusetts 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 2010/11 Winter (Peak) Period to be effective beginning November 1, 2010.

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 $0.8220 per therm for residential customers, $0.8234 per therm for commercial/industrial high winter use customers and $0.8186 per therm for commercial/industrial low winter use customers as shown on Proposed Sixteenth Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0009 per therm as shown on Proposed Second Revised Page 89.

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

A. Proposed Third Revised Page 86 and Proposed Sixteenth Revised Page 87 contain the calculation of the 2010/11 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 2010/11 Average Cost of Gas of $0.8220 per therm is derived by adding the Direct Cost of Gas Rate of $0.7869 per therm to the Indirect Cost of Gas Rate of $0.0351 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $65,369,088. The estimated Indirect Cost of Gas, also derived on Page 86 and repeated on Page 87, is $2,914,492. The Direct Cost of Gas Rate of $0.7869 and the Indirect Cost of Gas Rate of $0.0351 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 83,071,582 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 $1,741,780. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $63,627,308 to determine the Total Anticipated Direct Cost of Gas of $65,369,088. I should note that as part of the Company's pending general rate case, DG 10-017, the Company's indirect gas costs are currently being reviewed. Once the level of those costs is set, the final result will need to be reconciled through the cost of gas rates, consistent with the temporary and permanent rate orders in that case.

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

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

1.	Purchased Gas Demand Costs	$8,314,931
2.	Purchased Gas Commodity Costs	$39,083,750
3.	Storage Demand and Capacity Costs	$1,055,525
4.	Storage Commodity Costs	$7,649,468
5.	Produced Gas Cost	$1,255,498
6.	Hedge Contract Loss/(Savings)	$5,704,479
7.	Hedge Underground Storage Loss/(Savings)	$ 563,657
	Total	$63,627,308

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

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

1.	Prior Period Under Collection	$2,985,736
2.	Interest	101,158
3.	Broker Revenues	(754,779)
4.	Fuel Financing	130,835
5.	Transportation COG Revenue	(31,147)
6.	Interruptible Sales Margin	(0)
7.	Capacity Release Margin	(730,714)
8.	Fixed Price Administrative Cost	40,691
	Total Adjustments	$1,741,780

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 09-162 for the 2009/2010 Winter Period?

The average cost of gas rate proposed in this filing is $0.1443 per therm lower than the initial rate of $0.9663 approved by the Commission in Order No. 25,032 dated October 29, 2009 in DG 09-162. This decrease in the rate reflects a decrease in the total cost of gas of approximately $13.2 million, or 16% (a $12.5 million decrease in total direct gas costs and a $0.7 million decrease in indirect gas costs). The $12.5 million decrease in the total direct cost of gas is a result of a $15.8 million decrease in commodity costs, offset by a $1.3 million increase in demand costs and a $2.0 million increase in gas costs adjustments.

The $15.8 million decrease in commodity costs is due to a $16.5 million decrease in pipeline commodity costs offset by a $0.7 million increase in supplemental costs (underground storage, LNG, and propane). The $16.5 million decrease in pipeline costs is due to a decrease in commodity costs of $14.3 million and a decrease of $2.2 million resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are approximately $.19/therm lower than last year, resulting in a $14.3 million decrease while the throughput is down by 3.5 million therms resulting in a decrease in commodity costs of $2.2 million. The $2.0 million increase in adjustments reflects an increase in Prior Period Under Collection of $2.0 million.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2009/2010 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0009 per therm. The rate approved in DG 09-162 was ($0.0003). This increase is largely due to the increase in peaking costs as compared to the 2009/10 period.

Q. What was the actual weighted average firm sales cost of gas rate for the 2009/2010 winter period?

A. The weighted average cost of gas rate was approximately $0.9416 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2009 through April 2010 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 $2,484,517.

The prior period under collection is detailed in the 2009/2010 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $2,484,517 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2010 including Peak Period costs recovered in May 2010 based on billings for April consumption. The under collection is the result of lower gas revenue billings and sendout than forecasted for the months of March and April 2010. Specifically sales volumes were 6.4 million therms below the forecast, resulting in a reduction in COG revenues of $6.3 million. The reduction in sendout reduced gas costs by $3.8 million, reflecting the fact that the Company incurred the applicable demand costs but avoided the commodity costs associated with the decreased sendout.

FIXED PRICE OPTION

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

A. Yes, in Order No. 24,515 in docket DG 05-127, dated September 16, 2005, the Commission approved an amendment to the Fixed Price Option Program. In accordance with the approved changes to the FPO program, the FPO rates are set at $0.02 per therm higher than the initial proposed COG. Proposed Second Revised Page 88 contains the FPO rates for the 2010/11 Winter period, which are $0.8420 per therm for residential customers, $0.8386 per therm for commercial/industrial low winter use customers, and $0.8434 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2009/2010 winter period of $0.9863 per therm for residential customers, $0.9858 per therm for commercial/industrial low winter use customers, and $0.9865 per therm for commercial/industrial high winter use customers. This represents a $0.1443 per therm, or 14.6%, decrease in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a decrease of approximately $76 or 6.1% compared to last winter. The bill impact reflects the implementation of the increase in base distribution rates associated with the temporary rates approved in DG 10-017 effective June 1, 2010 and in the increase approved in DG 10-139 effective July 1, 2010 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 program would be approximately $19 or 1.6% higher than the bill under the proposed cost of rates assuming that the COG is not revised prior to final approval by the Commission and also assuming no monthly adjustments to the COG rate during the course of the winter. Tab 23 contains the historical results of the FPO program as required by Order No. 24,515 issued on September 16, 2005 in DG05-127.

<u>HEDGED SUPPLIES</u>

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 3,490,000 Dekatherms (34.9 million therms) at a weighted average fixed price of $6.4191 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 480,000 Dekatherms will be hedged at an estimated price of $4.8156 per Dekatherm based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 3,970,000 Dekatherms at a cost of $24,714,066 or approximately $6.2252 per Dth.

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

A. The Company has fifty-four contracts that hedge the price of gas supplies for the 2010/2011 Winter Period with prices ranging from $4.7580 to $7.4970 per Dekatherms. The contracts date as far back as May 15, 2009 and as recently as July 26, 2010. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

Q. Has the Company revised it Natural Gas Price Risk Management Plan?

Yes, the Company has revised in Natural Gas Price Risk Management Plan as approved in DG 10-049. Under its updated Natural Gas Price Risk Management Plan, the Company plans on hedging 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 little to no planned storage withdrawals in these months. The Company is now determining the financial hedge volume based on the total firm sales forecast, including forecasted storage withdrawals and fixed price physical purchases. As shown in Schedule 7, the total hedged volume (which included storage withdrawals and financial hedges) is approximately 61% of the total sendout during the period of November 2010 through April 2011.

LOCAL DISTRIBUTION ADJUSTMENT CHARGE

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

A. The Company is submitting for approval a Local Distribution Adjustment Charge of $0.0641 for the residential non heating class and residential heating class, and $0.0422 for the commercial/industrial classes that will be billed from November 1, 2010 through October 31, 2011. The surcharges that are billed under the LDAC are the Conservation Charge, the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, and the Residential Low Income Assistance Program charge as approved per (1) the Commission's Order in Docket DG 00-063, the

Company's Revenue Neutral Rate Redesign Case, (2) Order No. 24,109 in DG 02-106, Energy Efficiency for Gas Utilities, (3) Order No. 24,636 in DG 06-032, Energy Efficiency for Gas Utilities, and (4) Order No. 24,508 in DG 05-076 .

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover expenses associated with the Company's energy efficiency programs that were approved by the Commission in Order No. 24,995 dated July 31, 2009, in DG 09-049 for the period November and December 2010 and the 2011 expenses that were submitted for approval on August 2, 2010 in Docket DE 10-188 for the period January 2011 through October 2011. The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs during the period May 2009 through December 2009 that were approved by the Commission in Order 24,109 dated December 31, 2002 in DG 02-106 and Order 24,636 dated June 8, 2006 in DG 06-032. The incentive calculations that are included in this LDAC filing are based on Exhibit C 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 $0.0116. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this charge. For the 2010/11 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 $1,831,683, of which $1,879,126 is for the revenue shortfall resulting from 7,213 customers receiving a 60% discount off their base rates, $8,600 is for estimated administrative costs, and ($56,043) 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 2010-2011 period. As shown, the short term limit for fuel inventory financing for the period November 1, 2009 through October 31, 2010 is calculated to be $20,485,074 and the limit for non-fuel purposes is calculated to be $52,528,520.

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

A. Yes.

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

A. Yes, it has. As a result, of the Company's success in its third party cost recovery efforts, which included receiving significant insurance recoveries in prior years, the balance from recoveries from insurance carriers and other responsible parties continues to exceed the remediation costs. As a result, the Company proposes that the Environmental Surcharge remain at zero for the period beginning November 1, 2010 and ending October 31, 2011. The surcharge for the 2007/2008, 2008/2009, and 2009/2010 Winter Period was also $0.0000 per therm. 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 prefiled testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Tab 20. The Summary included in Tab 20, pages 1 – 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 a general settlement agreement between National Grid, NH and an insurance company covering more than one site, there is usually no distinction made as to how much of the settlement amount is associated with a particular site. The reason the recoveries are presented on the summary in this way is to reflect how the Company is recording them in its accounting records. In compliance with Commission Order No. 23,303, dated September 20, 1999 in docket DG 99-060, the

Company is crediting the third-party recoveries, net of expenses associated with those recoveries, to the end of the recovery period with the exception of those recoveries from prior plant operators that are contributions to the on-going expense of site investigation and remediation. Those amounts are netted out against the Company's expenses before any remaining balance is included for recovery through the MGP surcharge. Page 13 provides the total remediation and recovery costs and collections by year and in total.

Although the Company is not proposing an Environmental Surcharge for the 2010-2011 period, the Company's filing does summarize its total investigation and remediation costs, recoveries from third parties and surcharge collections to date so that the Commission is aware of the current ending balance. In total, the Company has incurred environmental remediation costs of $28,257,322, litigation costs of $7,178,376, and obtained third party cash recoveries of $22,792,408, for a net expense of $12,643,290. To date, the Company has collected $13,054,749 from its Environmental Surcharge factor. The total recoveries from insurance carriers and other responsible parties currently exceed the total expenses by $411,459. The Company proposes to apply this credit of $411,459 to future remediation and recovery costs. The $411,459 reflects an interest credit of $257,920. This interest has been included as a credit to the General Expense account.

The 2009-2010 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #10)	$136,936
Concord (Pool #6)	$46,190

Laconia (Pool #8)	$262,678
Manchester (Pool #9)	$328,678
Nashua (Pool #9)	$98,975
Keene (Pool #6)	$0
General (Pool #7)	$4,199
Total Remediation	$877,655
Litigation Recovery	0
Litigation Costs	0
Total 2009-2010	$877,655

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2009-10 costs that the Company is submitting. (Copies of the relevant invoices are being provided under separate cover to the Commission audit staff concurrently with this filing.) Consistent with past practice, the Company met with the Commission staff and Consumer Advocate's office 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 Order No. 24,849 in docket DG 07-129, the Commission ordered the Company to apply 80 percent of the interest earned from the over recovery of environmental

response costs to future remediation costs. Has the Company reflected these interest credits in this filing?

A. Yes, the Company has calculated the customers' portion of the interest credit associated with the recovery of environmental costs from third parties to the extent it exceeds the costs incurred by the Company that have not already been recovered from customers and has included these credits in the "General Expense" category. For 2009-2010 time period, the Company has included $9,395 credits in this account

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

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

Q. In the 2009-2010 LDAF, the Company included a credit associated with rate case expense and the true up of temporary rates in DG 08-009 and an emergency response incentive allowed per the EnergyNorth/National Grid Merger in DG 06-107. Did the Company over or under collect these costs during the 2009-2010 period?

A. The Company will not know until October 2010 the amount of the over or undercollection associated with these two factors. The Company proposes to incorporate the reconciliation balance (if any) for these two factors in the true-up of its Temporary Rates and Rate case expense in DG 10-017.

<u>CUSTOMER BILL IMPACTS</u>

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. 25,127 in Docket DG 10-139 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 $53, or 4.4% of which $89, or 7.4%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 20009/2010 winter season, offset by an increase of $37 or 3.0 % resulting from the implementation of temporary rates in DG 10-017 and the base rate adjustment in DG 10-139. The total bill impact for a typical commercial/industrial G-41 customer is an decrease of approximately $67, or 3.5%, of which $135, or 7.0%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2009/2010 winter season offset by an increase of $68, or 3.5%, resulting from the implementation of temporary rates in DG 10-017 and the baserate adjustment in DG 10-139. 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 Second Revised Page 155 relating to Supplier Balancing Charges and Proposed Second Revised Page 156 relating to Capacity Allocation.

Q. Please describe the changes to Page 155.

A. In Proposed Second Revised Page 155, the Company is updating the Peaking Demand Charge from $16.43 per MMBtu of Peak MDQ to $18.48 per MMBtu of Peak MDQ, a $2.05 increase.

The increase in the Peaking Demand Charge is a result of the reduction in the forecast of the Peak Day (ie- denominator used to derive the per unit peaking demand rate). This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions First Revised Page 155, Attachment B – Peaking Demand Charge.

Q. Please describe the changes to Page 156.

A. Proposed Second 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.