NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2015-2016
COST OF GAS ADJUSTMENT FILING

PREFILED TESTIMONY OF
<u>**FRANCIS X. WELLS**</u>

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. What is your relationship with Northern Utilities, Inc.?

A. I am employed by Unitil Service Corp. (the "Service Company") as Manager of Energy Planning. The Service Company provides professional services to Northern Utilities, Inc.

Q. Please briefly describe your educational and business experience.

A. I earned my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined the Service Company in September 1996 and have worked primarily in the Energy Contracts department. My primary responsibilities involve gas supply planning and acquisition.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I have testified as Northern's gas supply witness before the Commission in Northern's Cost of Gas Factor ("COG") proceedings.

Q. Please summarize your prepared direct testimony in this proceeding.

A. The purpose of my testimony is to present and support Northern's gas supply cost forecast, which was used for the calculation of the proposed COG. The 2015-2016 fixed, annual demand cost estimates are 6% lower than the 2014-2015 fixed, annual demand cost estimates provided for the prior Winter Period COG. Estimated average delivered commodity rates for the 2014-2015 Winter Period are 32% lower than the average delivered commodity rates estimated for the 2014-2015 Winter Period COG. I discuss reasons for these cost decreases in the body of my testimony below.

Northern projects combined sales service and delivery service distribution deliveries for the New Hampshire Division for the 2015-2016 Winter Period to be 5,780,607 Dth, which 1.7% higher than the 2014-2015 Winter Period weather-normalized distribution deliveries and 4.4% higher than the 2013-2014 Winter Period weather-normalized distribution deliveries. Of the 5,780,607 Dth of projected distribution system deliveries, Northern projects that 3,329,413 Dth will be supplied by the Company through Sales Service. In order to supply 3,329,413 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 3,363,097 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 434,534 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 3,797,631 Dth for the upcoming Winter Period. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern has the ability to deliver up to 120,754 Dth of contract supply and on-system peaking capacity per day during the peak winter months, November through March. This is a decrease equal to 3,827 Dth from the prior winter's maximum deliverability, which was equal to 124,581 Dth. This decrease is attributable in part to a reduction in the daily production capability of its LNG Plant upon which Northern relies from 10,000 Dth to 4,181 Dth (a decrease equal to 5,819 Dth). This amount is partially offset by an increase in off-system peaking contracts from 39,887 Dth to 41,879 Dth (an increase equal to 1,992 Dth). Northern's contract supply sources include Chicago City-Gates Supply, PNGTS Receipts, Tennessee Niagara, Tennessee Production, Algonquin Receipts, Maritimes Delivered and PNGTS Delivered baseload supply, Tennessee Firm Storage, Washington 10 Storage and Peaking Supply Contracts. Northern has system peaking LNG capacity in Lewiston, Maine. The details behind Northern's portfolio are contained in Schedule 12. I discuss changes to Northern's portfolio in more detail in the body of my testimony.

I project Northern's total company (including the Maine Division Division) demand cost for the November 2015 through October 2016 gas year to be $31,158,821. (*See* Schedule 5A). Mr. Chris Kahl, who is employed by Unitil Service Corp. as a Senior Regulatory Analyst, presents the allocation of the total annual demand cost to Northern's New Hampshire Division and the portion of that allocation of annual demand costs to be recovered in the Winter COG rate. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $2,872,046. (*See* Schedule 5B). This demand revenue is partially offset by the allocation of the PNGTS Refund to retail marketers in the amount of $182,564. The PNGTS Refund is allocated to retail marketers, as proposed by Northern in to the Commission in Docket No. DG15-090 (2015 Summer COG Filing).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2015-2016 Winter Period will be $43,667,878 at an average rate equal to $5.233 per Dth. (*See* Schedule 6A). I also calculated hedging program costs to be $207,790. (*See* Schedule 7). Mr. Kahl calculates the portion of these costs, which are allocated to the New Hampshre Division.

Finally, I provide updates to the various pipeline rate cases affecting Northern. These include TransCanada, PNGTS, Tennessee and Granite pipeline rate cases, which affect the demand cost estimates I have prepared.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm deliveries?

A. To forecast billed distribution deliveries for the Company's residential, small commercial and larger industrial/commercial classes, the Company has utilized time-series techniques to develop two forecast models for each customer class: use-per-meter and the number of meters. The forecast monthly billed deliveries for each customer class was calculated by multiplying forecast customers times forecast use-per-customer.

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. I have prepared Table 1, below, which provides a summary of the company's forecast of total billed distribution deliveries for the upcoming 2015-2016 Winter Period.

Table 1. 2015-2016 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years

Month	2015-2016 Forecast[1]	2014-2015 Actual[2]	2015-2016 minus 2014-2015	Percent Change	2013-2014 Actual[2]	2015-2016 minus 2013-2014	Percent Change
Nov	663,212	617,458	45,754	7.4%	647,370	15,842	2.4%
Dec	926,979	917,213	9,766	1.1%	873,633	53,346	6.1%
Jan	1,172,219	1,173,929	-1,710	-0.1%	1,142,123	30,096	2.6%
Feb	1,188,007	1,170,393	17,614	1.5%	1,129,162	58,846	5.2%
Mar	1,041,781	1,031,483	10,298	1.0%	1,009,416	32,365	3.2%
Apr	788,408	771,819	16,590	2.1%	732,697	55,711	7.6%
Winter	5,780,607	5,682,295	98,312	1.7%	5,534,401	246,207	4.4%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2015-2016 Winter Period in Attachment 1 to Schedule 10B. Page 1 of Attachment 1 to Schedule 10B provides total data for the Maine Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2015-2016 Winter Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2014-2015 and 2013-2014 Winter Periods. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment 1 to Schedule 10B provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. How does the Company forecast Sales Service deliveries?

A. To forecast Sales Service deliveries, Northern identified those customers utilizing Delivery Service as of June 1, 2015. Then, Northern weather normalized the billed usage of these specific customers. The weather normalized billed usage of current Delivery Service customers was subtracted from the billed distribution deliveries of the entire system, provided in Attachment 1 to Schedule 10B in order to estimate Sales Service deliveries.

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. I have prepared Table 2, below, which provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries, Company Managed Deliveries and City-Gate Receipts to meet the Sales Service Deliveries[1] for the upcoming Winter Period.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary

Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)	Company Managed Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-15	788,533	427,480	431,580	17,490	449,070
Dec-15	1,052,790	629,737	635,777	99,493	735,270
Jan-16	1,279,452	795,004	802,629	152,721	955,350
Feb-16	1,101,629	664,610	670,985	117,486	788,471
Mar-16	925,268	512,355	517,269	47,344	564,613
Apr-16	632,936	301,961	304,857	0	304,857
Winter	5,780,607	3,331,147	3,363,097	434,534	3,797,631

The detailed calculations can be found in Attachment 2 to Schedule 10B. On Pages 1 and 2 of Attachment 2 to Schedule 10B, I present calendar month and billed sales service deliveries by rate class. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the Maine Division.

On Page 3 of Attachment 2 to Schedule 10B, I present my calculations of the city-gate receipts. First, I estimated Company Use by multiplying the forecast Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, I added Company Use to the total Calendar Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use"). Then, I added an estimate for Lost and Unaccounted for Gas. Each of the estimates used in these calculations was based on the recent history of actual data, which are presented in Attachment 3 to Schedule 10B. Finally, I added Northern's projection of Company Managed Sales pursuant to the New Hampshire Division's capacity assignment program.

[1] When I use the term "City-Gate Receipts to meet the Sales Service Requirements", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

Q. Has Northern made changes to the calculation of the percentage of Lost and Unaccounted For Gas used for this estimate?

A. Yes. Please refer to the calculations in Attachment 3 to Schedule 10B. In my previous calculations of the percentage Lost and Unaccounted For Gas, I included net Unbilled Sales in Total Throughput Out. Inclusion of net Unbilled Sales in the calculation of Lost and Unaccounted For Gas was intended to adjust bill cycle sales to calendar month sales, thus putting Thoughput In (based on calendar month meter reads of gas entering Northern's Maine Division system) and Throughput Out (based on billed sales, gathered throughout the month) each on a calendar month basis. I believe that the inclusion of net Unbilled Sales in the percentage of Lost and Unaccounted For Gas calculation has led to exaggerated annual changes in this factor as the net Unbilled Sales can increase and decrease over time in a manner that is unrelated to actual gas flows. The fact that Northern uses a 48-month average to derive its projected percentage of gas Lost and Unaccounted For should mitigate timing differences between calendar month and bill cycle data, so the inclusion of net Unbilled Sales is unnecessary. For these reasons, my Lost and Unaccounted For Gas calculation no longer includes net Unbilled Sales. Attachment 3 to Schedule 10B provides my calculations of the Lost and Unaccounted For Gas percentage, as well as Company Use and the Company Gas Allowance factor assessed to retail marketers.

Q. What are Company Managed Sales?

A. Company Managed Sales are a form of Capacity Assignment. Capacity Assignment is a means of transferring the demand cost responsibility for capacity contracts from Northern to the retail marketers on its system. Whenever a retail marketer enrolls a customer, who is "capacity assigned," the retail marketer assumes cost responsibility for a pro-rated portion of the capacity contracts entered into by Northern, subject to the capacity assignment provisions of each division. These capacity contracts can include interstate pipeline contracts, underground storage contracts, peaking supply contracts and on-site peaking facilities. Such transfer may be achieved by releasing a portion of capacity directly to the retail marketer ("Capacity Release"), who may then purchase their own supplies and utilize the released contracts to deliver supplies to their customers. However, a portion of the capacity assignment for the New Hampshire Division is effectuated through Company Managed Supply, rather than capacity release. The resource assigned via Company Managed Supply include resources that require either the Bay State Exchange or non-U.S. transportation capacity for delivery to Northern, as well as all peaking resources. Under the Company Managed Supply form of capacity assignment, Northern bills the retail marketer for a pro-rated portion of the associated demand costs and offers a city-gate delivered supply service. Such city-gate supplies are priced in accordance with the capacity assignment provisions of each division. Such arrangements are known as "Company Managed Sales."

Q. Please explain the process used to project Company Managed Sales for the New Hampshire Division.

A. Company Managed resources for the New Hampshire Division include pipeline (specifically Chicago City-Gates and Algonquin Receipts capacity paths), storage (Washington 10) and peaking resources. The maximum daily volume of each Company managed resource was estimated, based on current capacity assigned transportation customer data. Northern allows marketers to nominate their storage and peaking Company managed resources on a daily basis. In addition, marketers are required to purchase pipeline baseload supplies that are associated with the Company Managed pipeline resources. The Company Managed Sales forecast assumes that marketers will utilize all pipeline, storage and peaking Company managed supply available to them under the capacity assignment program.

Q. Please explain why Northern provides Company Managed sales in its city-gate sendout projections and its gas supply dispatch analysis.

A. Company Managed sales are a significant portion of Northern's gas supply obligation, particularly due to the nature of Northern's capacity assignment program for the Maine Division. Since Northern maintains resources to fulfill these Company Managed supply obligations for both the Maine and New Hampshire Divisions, it is appropriate to include them in the gas supply dispatch analysis in order to demonstrate the expected utilization of resources.

III. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its Sales Service customers and meet Company Managed Supply obligations.

A. I have prepared Table 3, below, which provides an overview of the sources of supply available to Northern through its portfolio of contracts, including transportation contracts, storage contracts, baseload and peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table 3. Northern Capacity by Supply Source (Dth per Day)		
Supply Source	Nov 2015 through Mar 2016	Apr 2016 through Oct 2016
Chicago City-Gates & Iroquois Receipts	6,434	6,434
PNGTS Receipts	1,096	1,096
Tennessee Niagara	2,327	2,327
Tennessee Production	13,109	13,109
Algonquin Receipt Points Supply	1,251	1,251
Maritimes Delivered Baseload Supply	7,474	0
PNGTS Delivered Baseload Supply - (Nov - Mar)	4,983	0
PNGTS Delivered Baseload Supply - (Dec - Feb)	2,491	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Contract 1	9,965	0
Peaking Contract 2	14,948	0
Peaking Contract 3	5,000	0
Peaking Contract 4	11,966	0
Lewiston On-System LNG Production	4,181	4,181
Total Deliverable Resources	**120,754**	**31,042**

I have also prepared a capacity path diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Deliverable Capacity listed for each source of supply. This information is found in Schedule 12.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Tennessee Gas Pipeline Company ("TGP" or

"Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited ("TransCanada"), Vector Pipeline L.P. ("Vector"), Union Pipelines Ltd. ("Union"), Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Washington 10 Storage Corporation ("Washington 10" or "W10"), Tennessee and Texas Eastern. Northern's gas supply portfolio includes two separate peaking supply agreements. These peaking supply arrangements were procured through a Request-For-Proposals ("RFP") and have a delivery period beginning November 2015 and ending March 2016. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 4,181 Dth per day and storing approximately 12,000 Dth of LNG. Northern has entered into an LNG Contract beginning November 2015 and ending October 2016 in order to supply this facility. Finally, as I mentioned previously, the gas supply portfolio consists of an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement").

The capacity path diagrams and capacity path details in Schedule 12 show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, in order to move natural gas supplies from the sources of supply listed in Table 3 to Northern's distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path diagrams show how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Q. Has the Company entered into any long-term releases of capacity?

A. Yes. Effective May 1, 2009, Northern released Texas Eastern Contract 800384 for the remaining term of the agreement, which is through October 31, 2017. This release is at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contract.

Q. Please describe the Company's process for procuring its gas supply commodity supplies.

A. Northern's practice is to secure most of its gas supply and asset management services through an annual RFP for terms beginning April 1 and running through March 31 each year. Northern has recently completed its annual RFP for the delivery period of April 1, 2015 through March 31, 2016. Northern has entered into asset management agreements for its Chicago capacity path, Algonquin Receipts capacity path, Niagara capacity path, a portion of its Tennessee Production capacity path and its Washington 10 capacity path. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for peaking supplies in early July, including an LNG Contract for the upcoming winter.

Q. Please describe any changes in Northern's portfolio for the upcoming 2015-2016 Winter compared to the portfolio relied upon for the 2014-2015 Winter.

A. The major changes in the portfolio include the following items.

1. Northern's contract with Granite State Gas Transmission will be modified to reflect 115,000 Dth of capacity for the months of November through April and

85,000 Dth of capacity for the months of May through October. For the 2014-2015 gas year, Northern has a contract for 100,000 Dth of capacity for the entire November through October period. Consistent with the Maine Public Utilities Commission's directive in Docket No. 2015-00087, Northern has executed an agreement with Granite, reflecting these seasonal volumes.

2. The Capacity rating for the LNG Plant has been reduced by Northern from 10,000 Dth to 4,181 Dth, as described in Northern's 2015 IRP (See Page VI-109.), to reflect the limitations of on-site storage and challenges associated with refilling the facility during peak winter weather.
3. Northern has increased its off-system Peaking Contracts by approximately 2,000 Dth over the 2014-2015 Winter portfolio. This increase in Peaking Contract capacity is due to higher anticipated design day demand for Northern's short-term planning load requirements, specifically design day Sales Service requirements for Maine and New Hampshire plus Company Managed supply obligations for Maine and New Hampshire.
4. For the 2014-2015 Winter Portfolio, Northern had purchased 7,500 Dth per day of PNGTS supply for November through March. Northern has reduced the volume of November through March PNGTS purchase to 5,000 Dth per day. However, Northern plans to purchase 2,500 Dth per day for the peak winter months of December through February PNGTS supply. This change will provide Northern the supply it needs to meet projected demands in the coldest winter months, while providing more flexibility in November and March by reducing winter baseload commitments.

IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Kahl to calculate the 2015-2016 Winter COG.

A. I have provided Mr. Kahl the following cost estimates, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities for the period November 2015 through October 2016
- Maine Division Capacity Assignment program demand revenues for the period November 2015 through March 2016
- Northern's commodity costs for the period November 2015 through October 2016
- Northern's financial hedging program costs period November 2015 through March 2016

The allocation of Northern's fixed demand, commodity and hedging costs to the Maine Division was performed by Mr. Kahl. The figures I present in my testimony relate to total company costs, inclusive of both the Maine and New Hampshire Divisions.

Q. Were any other adjustments made to the demand cost allocation process in order to adjust for the migration of the Portsmouth Naval Shipyard ("PNSY") to Maine Division Sales Service?

A. Yes. I made an adjustment to the Maine Division's Proportional Responsibility Allocator SENDOUT volumes due the migration of PNSY from Delivery Service to Sales Service.

Under the settlement agreement (Docket No. 05-080), which defines the process to determine demand cost allocation between the Maine and New Hampshire Division, Maine SENDOUT volumes are equal to Maine sales load and fifty percent (50%) of the Maine Division's total firm transportation load for the 12-month period ending April 2015.

The PNSY elected Maine Division Sales Service effective April 1, 2015. Under the literal reading of the settlement agreement, 50% of PNSY consumption would be considered from May 2014 through March 2015, since PNSY was a Delivery Service customer for this period of time. Considering that Northern must now plan for 100% of this customer's consumption for the upcoming winter period, and that cost of gas rates are established on a forward-looking basis, I believe it is appropriate to calculate Maine's Proportional Responsibility Allocation for demand costs on the basis that the Maine Division is responsible for 100% of PNSY's load. Therefore, I adjusted the Maine SENDOUT volumes to reflect 100% of PNSY's load for the 12-month period ending April 2015. If and when PNSY elects Delivery Service in the future, I anticipate a similar adjustment would be made to reflect the applicable prospective percentage responsibility of the Maine Division.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 4, below, titled, "Estimated Gas Supply Demand Costs."

Table 4. Estimated Gas Supply Demand Costs November 1, 2015 through October 31, 2016			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 9,154,859	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 23,128,453	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,029,855	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,252,642	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 4,223,000	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (9,629,987)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 31,158,821	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 5A. Page 1 of Schedule 5A provides the summary data presented here in Table 4. On page 2 of Schedule 5A, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Schedule 5A, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 4 and 5 of Schedule 5A provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Schedule 5A, I forecast the capacity release and asset management revenue the Company expects to receive for the 2015-2016 Gas Year. Support for the transportation, storage and supply demand rates used in Schedule 5A are found in the Attachment to Schedule 5A, Supplier Prices.

Q. How do 2015-2016 Winter COG forecasted annual demand costs compare with the 2014-2015 Winter COG forecasted annual demand costs?

A. 2014-2015 Winter COG forecasted annual demand costs were equal to $33,160,587. 2015-2016 Winter COG forecasted annual demand costs are equal to $31,158,821, reflecting a decrease in forecasted annual demand costs equal to $2,001,766 or 6%. The decrease in projected demand costs is attributable to the following:

1. <u>Decrease in pipeline contract demand cost equal to $4,661,911.</u> This is due to lower PNGTS and Tennessee rates and a more favorable exchange rate. These items are partially offset by higher Granite costs. Lower PNGTS rates account for the overwhelming majority of this decrease. The majority of the PNGTS demand cost decrease is shown in Table 4 above under Storage Allocated Pipeline Demand Costs.
2. <u>Partially offsetting increases due to reduced AMA credits and increased peaking contract demand costs.</u> Projected AMA credits are down by $1,715,685 and peaking contract demand costs are up by $951,450 due to the results of Northern's request for proposals process.

Q. Please provide Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of the demand revenues from capacity assignment in Schedule 5B. On page 1 of Schedule 5B, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Schedule 5B, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Schedule 5B. The 2015-2016 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,872,046. This amount is reduced by $182,564, reflecting the projected allocation of the PNGTS refund to retail marketers, as proposed by Northern in Docket No. DG15-090. The actual allocation of the refund to retail marketers will reflect the Commission's decision on Northern's proposal to allocate the PNGTS refund to marketers on the basis of prospective PNGTS capacity allocations over the three-year period the PNGTS refund will provide a credit to the New Hampshire Division Cost of Gas.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2015, through April 2016?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 7 of Schedule 5B. The proposed Peaking Service Demand Charge is equal to $23.40 per Dth, as shown in Schedule 5B and presented in the proposed revised Appendix A to the Delivery Service Terms and Conditions.

Q. Please describe Northern's process for forecasting commodity costs.

A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts for sales service customers, which I calculated in Attachment 2 to Schedule 10B, and the supply sources available to Northern, which I presented in Schedule 12. I forecast supply prices at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. Then, I utilized the Sendout® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.

Q. Please present the Company's commodity cost forecast for the 2015-2016 Winter Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter Period in Table 5, below.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes November 2015 through April 2016			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 36,241,812	6,430,186	$ 5.636
Storage Resources	$ 7,834,071	2,462,507	$ 3.181
Peaking Resources	$ 5,247,573	443,063	$ 11.844
Total Commodity Costs	$ 49,323,457	9,335,756	$ 5.283
Company Managed Revenue	$ (5,655,578)	(990,612)	$ 5.709
Net Sales Service Commodity Costs	$ 43,667,878	8,345,144	$ 5.233

In summary, net projected delivered commodity costs equal approximately $43.7 million at an average delivered rate of $5.233 per Dth. In support of this forecast, I prepared Schedule 6A to show the monthly forecasted commodity cost by supply option. Page 1 of Schedule 6A provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Schedule 6A provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

The detailed calculations of the delivered commodity cost are found in Schedule 6B. For each supply source, I have provided the detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by Northern in order to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support of the supply prices and variable transportation charges found in Schedule 6B are found in the Attachment to Schedule 5A, Supplier Prices.

Q. How do 2015-2016 Winter COG forecasted Winter Period (November through April) commodity costs compare with the 2014-2015 Winter COG forecasted Winter Period commodity costs?

A. As show in Table 5, above, the 2015-2016 Winter COG forecasted Winter Period commodity costs are equal to $43,667,878 at an average delivered rate of $5.233 per Dth. The 2014-2015 Winter COG forecasted Winter Period commodity costs were equal to $52,250,353 at an average delivered rate of $7.724 per Dth. 2015-2016 forecasted Winter Period commodity costs are 16% lower than 2014-2015 forecasted Winter Period costs due to 32% lower average delivered rates, offset by an increase in forecasted Sales Service volumes (Maine and New Hampshire combined) equal to 23%.

Lower forecasted 2015-2016 average delivered rates compared to projected 2014-2015 average delivered rates reflect the following factors:

- Average NYMEX prices for November through April have decreased since Northern filed its 2014-2015 Winter COG. NYMEX prices for November 2014 through April 2015 averaged $3.98 per Dth in the Company's initial 2014-2015 Winter COG filing (based on September 2, 2014 NYMEX data). This filing reflects November 2015 through April 2016 NYMEX prices that average $2.91 per Dth (based on September 4, 2015 NYMEX data), which is a reduction equal to 36%. In addition to the decrease in NYMEX prices, there is also a decrease in the adders to NYMEX prices for supplies that Northern can access through its portfolio of pipeline contracts. These adders can be found on page 1 of the Attachment to Schedule 5A.

- The 2015-2016 average delivered rates reflect a lower percentage of New England based supply volumes[2] and lower prices for New England based supplies in general. Based on seasonal volumes found in Schedule 6A of the 2014-2015 COG, New England based supplies accounted for approximately 40% of the 2014-2015 projected volumes (2.6 million Dth of New England based supplies out of 6.8 million Dth net supply requirement). New England based supplies account for only 32% of the 2015-2016 projected volumes (2.7 million Dth of New England based supplies out of 8.3 million Dth net supply requirement).

While New England based supply volumes remain expensive relative to supplies that can be accessed using Northern's portfolio of transportation contracts, New England based supply prices are lower than they were a year ago. Northern remains concerned about the volatility of the New England gas supply market and the exposure of customers to New England gas prices. Northern seeks to manage its portfolio of gas supply contracts in a manner that can reliably meet its customer's needs and protect customers from the extremely volatile and high prices, such as those recently observed in the New England natural gas market.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2015 through October 2016.

A. Please refer to Schedule 14. These results are based upon the Company's Sendout® analysis, which I provided to Mr. Kahl.

[2] New England based supplies include Tennessee Zone 6 Delivered, Maritimes Delivered, PNGTS Delivered supplies and Peaking Contract supplies.

Q. Please provide the results of the hedging program related to the Company's proposed COG rates.

A. Northern projects hedging program costs to be $207,790 for the upcoming winter peak season, which reflects the premium paid by Northern for call option contracts for November 2015 through March 2016. Since the strike price for each call option contract purchased is above current NYMEX prices as of September 4, 2015, Northern projects no settlement value for these call options as they expire over the course of the coming winter. Please refer to Schedule 7 for the monthly hedging calculations.

V. PIPELINE RATE CASE UPDATES

Q. Please list the pipeline rate cases that impact the cost estimates you have provided for the 2015-2016 gas year.

A. The following rate cases have impacted the gas supply costs estimates I have prepared:

- FERC Docket No. RP10-729 - Portland Natural Gas Transmission System ("PNGTS")
- TransCanada Settlement with Eastern Canadian LDCs – Compliance Filing
- Tennessee Gas Pipeline – Rate Case Settlement
- Granite – Rate Case Settlement
- Union – Union Gas filed a rate case with the Ontario Energy Board on June 30, 2015.

Q. Please provide an update on the 2010 PNGTS Rate Case.

A. Northern actively participated in opposition to the 2010 rate case filed by PNGTS as a member of the Portland Shippers Group ("PSG"). FERC issued its initial order on the 2010 PNGTS Rate Case ("Opinion 524") on March 21, 2014. Requests for Rehearing on Opinion 524 were filed by the PSG and PNGTS in April 2014. On February 19, 2015, FERC issued Opinion 524-A denying most of PSG's and PNGTS's requests for rehearing. Also, in Opinion 524-A, FERC ordered PNGTS to submit revised tariff sheets by March 23, 2015, and to submit refunds to shippers by April 20, 2015. The revised tariff sheets became effective on February 1, 2015. On April 15, 2015, PNGTS refunded Northern approximately $22 million. Under the decision in RP10-796, PNGTS's reservation charges for its annual service decreased from $40.2456 per Dth to $25.9842 per Dth. PNGTS' reservation charges for its winter-only service decreased from $76.466 per Dth to $49.3701 per Dth.

Q. Does the proposed COG reflect the compliance rates approved by the FERC in RP10-796?

A. Yes. The lower PNGTS rates result in nearly $4.7 million in lower pipeline demand costs compared to last year's estimates.

Q. Is Northern seeking recovery of litigation expenses related to the PNGTS Rate Cases in the proposed COG?

A. Yes. Northern is seeking approximately $2,019 in PNGTS Rate Case litigation costs.

Q. Please provide an update of the TransCanada Application for approval of the Settlement with the Canadian LDCs.

A. The Canadian National Energy Board ("NEB") approved TransCanada's settlement with the Eastern Canadian LDCs (Union Gas, Enbridge Gas and GazMetro), effective January 1, 2015, approving a 52% increase in TransCanada tolls. On March 31, 2015, in compliance with the NEB's order, TransCanada filed updated tolls, applicable for 2015 through 2020, which reflected actual cost and sales data through 2014. This updated filing resulted in an additional 2% increase in tolls and was approved by the NEB effective July 1, 2015. TransCanada is required to file new tolls with the NEB by December 31, 2017 for the 2018 through 2020 period.

Q. Does the proposed COG reflect the rate increases proposed in the TransCanada Settlement?

A. Yes. My demand cost estimates reflect the recently approved Compliance Filing tolls. However, more favorable exchange rates result in lower expected TransCanada costs for the 2015-2016 period.

Q. Please describe the Tennessee Gas Pipeline rate change to take effect on November 1, 2015.

A. On May 15, 2015, Tennessee filed a settlement with the FERC in lieu of a general rate case under Docket No. RP15-990-000. Northern participated in this settlement through the New England LDC Customer Group. This settlement agreement provides for a 3% reduction in Tennessee demand, commodity and storage rates, effective November 1, 2015. FERC approved the settlement on July 1, 2015.

Q. Does the proposed COG reflect the Tennessee Gas Pipeline rate decrease approved by the FERC?

A. Yes. The proposed COG reflects approximately $124,000 of demand cost savings attributable to the rate decrease achieved through the settlement.

Q. Please describe the Granite State Gas Transmission rate change, which took effect on August 1, 2015.

A. On June 11, 2015, Granite filed a settlement with the FERC in lieu of a general rate case under Docket No. RP10-896-003. This settlement agreement provided for the continuation of an annual tracker for various investments required for the Granite pipeline system. Under the settlement agreement, Granite's monthly demand rate for firm service increased from $3.8633 per Dth to $4.1069, an increase of approximately 6.3%. A further increase in rates to $4.2845 per Dth is projected to be effective August 1, 2016. This settlement was approved by the FERC on July 31, 2015.

Q. Does the proposed COG reflect the proposed rate increase approved by the FERC?

A. Yes. The demand cost estimates reflect the increase in rates approved effective August 1, 2015 and the projected increase to be effective August 1, 2016. This results in an increase in Granite demand costs equal to approximately $340,000 on an annual basis.

Q. Please describe the toll and tariff changes, which Union Gas has requested of the Ontario Energy Board.

A. On June 30, 2015, Union filed an application with the Ontario Energy Board ("OEB"), seeking increases in its approved tolls and changes to its terms of service. Toll increases are requested to take effect on January 1, 2017 (19% above current tolls) and January 1, 2018 (41% above current tolls). These tolls are requested to support Union system expansion to fulfill contracts requested through a recently completed open season. Union also seeks "term up" provisions, similar to those recently approved by the NEB for TransCanada, which would require existing shippers to extend the terms of their contracts up to five years any time Union invested more than $20 million to expand its system. Northern will monitor and participate in the Union proceedings at the OEB through the ANE customer group.

Q. Does the proposed COG reflect the proposed toll changes sought by Union Gas?

A. No. The proposed toll increases will not affect the current winter period. If approved, they will affect the 2016-2017 COG.

Q. Does this conclude your testimony?

A. Yes it does.