NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2014-2015
COST OF GAS ADJUSTMENT FILING

PREFILED TESTIMONY OF
FRANCIS X. WELLS

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 Adjustment ("COG") filings since Unitil Corporation acquired Northern in December 2008. I have also testified numerous times before the Commission on behalf of Northern's affiliate, Unitil Energy Systems, Inc., on electric supply related matters.

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 2014-2015 fixed, annual demand cost estimates are 23% higher than the 2013-2014 fixed, annual demand cost estimates provided for the prior Winter Period COG. Estimated average delivered commodity rates for the 2014-2015 Winter Period are 34% higher than the average delivered commodity rates estimated for the 2013-2014 Winter Period COG. I discuss reasons for these cost increases in the body of my testimony below.

Northern projects combined sales service and transportation-only distribution deliveries for its New Hampshire Division for the 2014-2015 Winter Period to be 5,814,542 Dth, which is 6.3% higher than the 2013-2014 Winter Period weather-normalized distribution deliveries and 14.2% higher than the 2012-2013 Winter Period weather-normalized distribution deliveries. Of the 5,814,542 Dth of projected distribution system deliveries, Northern projects that 3,204,634 Dth will be supplied by the Company through Sales Service. In order to supply 3,204,634 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 3,226,120 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 390,760 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 3,616,880 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 124,581 Dth of contract supply and on-system peaking capacity per day during the peak winter months, November through March and 36,861 Dth per day during the months of April through October. 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 project Northern's total company (including the Maine Division) demand cost for the November 2014 through October 2015 gas year to be $33,160,587. (*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's Division's capacity assignment program to be $2,923,632. (*See* Schedule 5B).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2014-2015 Winter Period will be $52,250,353 at an average rate of $7.724 per Dth. (*See* Schedule 6A). I also calculated hedging program costs to be $58,460. (*See* Schedule 7). Mr. Kahl calculates the portion of these costs which are allocated to the New Hampshire Division.

Finally, I provide updates to the PNGTS and TransCanada pipeline rate cases affecting Northern.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm deliveries?

A. To forecast metered 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. Separate sets of forecast models were developed for both the total distribution system deliveries (based on historic total distribution system sales data) and for sales service deliveries (based on historic sales service data).

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 2014-2015 Winter Period.

Table 1. 2014-2015 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years

Month	2014-2015 Forecast[1]	2013-2014 Actual[2]	2014-2015 minus 2013-2014	Percent Change	2012-2013 Actual[2]	2014-2015 minus 2012-2013	Percent Change
Nov	666,556	626,941	39,615	6.3%	511,721	154,835	30.3%
Dec	899,446	846,547	52,898	6.2%	801,556	97,890	12.2%
Jan	1,197,339	1,126,289	71,049	6.3%	1,046,910	150,429	14.4%
Feb	1,196,059	1,125,318	70,741	6.3%	1,076,904	119,155	11.1%
Mar	1,066,133	1,003,409	62,724	6.3%	956,164	109,969	11.5%
Apr	789,010	743,126	45,884	6.2%	700,207	88,803	12.7%
Winter	5,814,542	5,471,630	342,912	6.3%	5,093,461	721,081	14.2%

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 2014-2015 Winter Period in Attachment 1 to Schedule 10B. Page 1 of this Attachment provides total data for the New Hampshire 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 2014-2015 Winter Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the

2013-2014 and 2012-2013 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 the 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. 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-14	795,914	411,391	413,999	34,804	448,803
Dec-14	1,056,614	606,043	609,885	81,127	691,012
Jan-15	1,281,064	765,096	769,946	122,398	892,344
Feb-15	1,105,051	639,605	643,660	101,808	745,468
Mar-15	932,830	493,072	496,198	50,623	546,821
Apr-15	643,069	290,590	292,432	0	292,432
Winter	5,814,542	3,205,797	3,226,120	390,760	3,616,880

The detailed calculations can be found in Attachment 2 to Schedule 10B. On Pages 1 and 2 of this Attachment, I present calendar month and billed sales service deliveries by

[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.

rate class. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire 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.

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 has chosen to include this item 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, due to the nature of Northern's capacity assignment program for the Maine Division[2], as well as its reliance on resources that require Canadian pipeline transportation for delivery to the Company's system and due to its reliance on delivered peaking supply contracts. Northern believes that inclusion of the Company Managed supply obligations for both New Hampshire and Maine Divisions in its gas supply dispatch analysis is necessary to better 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.

[2] Under the Maine capacity assignment program, all capacity assignment volumes are effectuated through Company Managed Supply.

Northern Capacity by Supply Source (Dth per Day)		
Supply Source	Nov 2014 through Mar 2015	Apr 2015 through Oct 2015
Chicago City-Gates Supply	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	7,474	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Contract 1	19,930	0
Peaking Contract 2	19,957	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**124,581**	**36,861**

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 long-term 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 2014 and ending March 2015. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 10,000 Dth per day and storing approximately 12,000 Dth of LNG. Northern has entered into an LNG Contract beginning November 2014 and ending October 2015 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 its gas supply commodity supplies through annual RFP for terms beginning April 1 and running through March 31 each year. Northern completed its annual RFP for the delivery period of April 1, 2014 through March 31, 2015, during the months of February and March of this past winter. 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, including an LNG Contract for the upcoming winter.

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 2014-2015 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 2014 through October 2015
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2014 through March 2015
- Northern's commodity costs for the period November 2014 through October 2015
- Northern's financial hedging program costs period November 2014 through March 2015

The allocation of Northern's fixed demand, commodity and hedging costs to the New Hampshire 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. 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, 2014 through October 31, 2015

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 9,039,940	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 27,667,462	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,490,461	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 3,271,550	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,345,672)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 33,160,587	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 2014-2015 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 2014-2015 Winter COG forecasted annual demand costs compare with the 2013-2014 Winter COG forecasted annual demand costs?

A. 2013-2014 Winter COG forecasted annual demand costs were equal to $26,905,064. 2014-2015 Winter COG forecasted annual demand costs are equal to $33,160,587, reflecting an increase in forecasted annual demand costs equal to $6,255,523 or 23%. Of this $6,255,523, $3,427,199 is attributable to pipeline contract cost increases, $610,524 is attributable to decreases in asset management and capacity release revenue and $2,217,800 is attributable to increases in peaking supply contract and LNG contract demand costs.

Of the $3,427,199 in forecasted pipeline contract cost increases, approximately $3.1 million of this amount is attributable to the proposed TransCanada Settlement with Canadian LDCs, which I discuss in further detail under the Pipeline Rate Cases section of my testimony and approximately $350,000 is attributable to increases in Granite demand costs due to Granite's rate increase effective August 1, 2014, pursuant to

Granite's limited Section 4 rate filing. Projected TransCanada and Granite pipeline contract increases are partially offset by projected lower demand rates on other pipelines.

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 2014-2015 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,923,632.

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. Forecast of both supply prices and variable transportation rates can also be found in the Attachment to Schedule 5A. 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 2014-2015 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 2014 through April 2015

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 43,187,621	5,304,639	$ 8.141
Storage Resources	$ 10,442,295	2,298,132	$ 4.544
Peaking Resources	$ 7,508,263	364,480	$ 20.600
Total Commodity Costs	$ 61,138,179	7,967,251	$ 7.674
Company Managed Revenue	$ (8,042,918)	(1,096,334)	$ 7.336
Off-System Sales Revenue	$ (844,908)	(105,967)	$ 7.973
Net Sales Service Commodity Costs	$ 52,250,353	6,764,951	$ 7.724

In summary, net projected delivered commodity costs equal approximately $52.3 million at an average delivered rate of $7.724 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.

Q. How do 2014-2015 Winter COG forecasted Winter Period (November through April) commodity costs compare with the 2013-2014 Winter COG forecasted Winter Period commodity costs?

A. The 2014-2015 Winter COG forecasted Winter Period commodity costs are equal to $52,250,353 at an average delivered rate of $7.724 per Dth. The 2013-2014 Winter COG forecasted Winter Period commodity costs were equal to $33,182,698 at an average delivered rate of $5.747 per Dth. 2014-2015 forecasted Winter Period commodity costs are 57% higher than 2013-2014 forecasted Winter Period costs due to 17% higher forecasted Sales Service volumes (Maine and New Hampshire combined) and 34% higher average delivered rates.

The increase in forecasted Sales Service volumes for the 2014-2015 Winter Period compared to the 2013-2014 Winter forecasted Sales Service volumes is driven by higher than forecast actual 2013-2014 Sales Service volumes. New Hampshire Sales Service billed volumes were projected to be equal to 2,806,475 Dth for the 2013-2014 Winter Period, whereas 2014-2015 New Hampshire Sales Service is forecasted to be 3,205,797 Dth, representing a 15% increase in projected New Hampshire Sales Service volumes over the prior year.

Higher forecasted 2014-2015 average delivered rates compared to 2013-2014 average delivered rates reflect higher New England based supply volumes[3] and higher prices for New England based supplies in general. Northern's need for higher New England based volumes is due to increased projected volumes, as discussed above. Higher prices for

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

New England based supplies 2014-2015 over 2013-2014 are due to the lack of relief of the pipeline constraints into New England, caused by increased New England demand without an increase of pipeline capacity into New England and Northern's increasing reliance on market area supplies. While New England based supply volumes are expensive relative to supplies that can be accessed using Northern's portfolio of transportation contracts, each of these supplies is needed to assure that Northern can reliably meet its customer's needs and protects customers from the extremely volatile and high prices observed in the New England natural gas market this past winter.

Q. Please provide a summary of capacity utilization by supply source projected for the upcoming Winter Period.

A. Please refer to Schedules 11A, 11B and 11C. Schedule 11A provides monthly supply volumes for Northern's normal weather scenario. The data in Schedule 11A is also found in Schedule 6A. Schedule 11B provides monthly supply volumes for Northern's design cold weather scenario. Schedule 11C calculates the capacity utilization of all supply resources in both normal and design cold weather scenarios.

Q. Please provide Northern's Design Day Report for the upcoming Winter Period.

A. Northern's Design Day Report is found in Schedule 11D.

Q. Please provide Northern's 7-Day Cold Snap Analysis for the upcoming Winter Period.

A. Northern's 7-Day Cold Snap Analysis is found in Schedule 11E.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2014 through October 2015.

A. Please refer to Schedule 14. These results are based upon the Company's Sendout® analysis.

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 $58,460 for the upcoming winter peak season, which reflects the premium paid by Northern for call option contracts for November 2014 through March 2015. Since the strike price for each call option contract purchased is above current NYMEX prices as of September 2, 2014, 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 currently affecting Northern Utilities, Inc.

A. Northern is currently involved in the following pipeline rate cases:

- Portland Natural Gas Transmission System ("PNGTS") has filed rate cases under FERC Docket Nos. RP08-306 ("2008 PNGTS Rate Case") and RP10-729 ("2010 PNGTS Rate Case") that have not been fully resolved.
- TransCanada Pipelines Limited filed an application with the NEB on December 20, 2013, seeking approval of a settlement agreement ("Settlement") that TransCanada reached with the three largest Canadian local distribution companies ("Canadian LDCs"), which would increase tolls on Northern's contracts with TransCanada by approximately 50 percent above the tolls approved by the National Energy Board's ("NEB") in its March 27, 2013, decision

on the 2013 and 2014 TransCanada Tolls Application ("NEB Order"), which had been filed on September 1, 2011.

Q. Please provide an update to the 2008 PNGTS Rate Case.

A. On May 21, 2013, PNGTS refunded reservation charges that were paid subject to refund, including interest, to Northern. This refund was returned to customers in the 2013-2014 Winter COG and 2014 Summer COG. However, PNGTS has appealed the FERC's decision in this proceeding and the appeal has not been ruled on.

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

A. FERC issued its Order on the 2010 PNGTS Rate Case Initial Decision ("Opinion 524") on March 21, 2013. Requests for Rehearing on Opinion 524 were filed by the Portland Shippers Group ("PSG") and PNGTS in April 2013. There has been no further activity and Northern continues to await FERC action on these Requests for Rehearing.

Q. Does the proposed COG reflect the rate increases proposed in the 2010 PNGTS Rate Case?

A. Yes. The forecast gas supply demand costs include costs projected at the 2010 PNGTS filed rates.

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

A. No. Northern has incurred no PNGTS Rate Case litigation expenses since the 2013-2014 Winter COG filing.

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

A. On December 20, 2013, TransCanada filed with the NEB for approval of a Settlement with the Canadian LDCs. The Settlement involves segmenting the eastern portion of the mainline from the western portion of the mainline, with increased tolls along the eastern portion reflecting a premium to cover revenue shortfalls on the western portion for the period of 2015-2020. Post 2020, the eastern portion tolls would be separate from the western portion. Upon approval, TransCanada would be willing to construct new short haul transportation capacity in the east, but would require 15 year commitments. In response to the NEB order issued in March 2013, TransCanada had taken the position they would not expand its system so long as any capacity remained unsubscribed, including capacity on the western portion of the system.

The impact of the proposed Settlement would be to undo the rate certainty that had been established under the NEB Order, which provided for multi-year fixed tolls through December 31, 2017, which were significantly lower than the tolls in effect prior to the 2012 and 2013 TransCanada Tolls Application. Instead, the Settlement introduces higher rates for the last three years of this period and beyond. Toll increases would be approximately 50 percent above tolls determined in the NEB Order. In addition, TransCanada would retain its new enhanced pricing flexibility in discretionary markets that were provided for under the NEB Order. TransCanada would also gain the right to unilaterally require shippers, including Northern, to extend agreements whenever TransCanada plans to invest to expand its pipeline to meet new contract requirements. Currently, Northern has the right to extend or terminate its contracts upon two years notice prior to the current termination date.

Northern monitors and participates in the NEB process for review of the Settlement as a member of Alberta Northeast Gas, Limited (“ANE”). On July 4, 2014, ANE filed evidence with the NEB, which opposed the TransCanada Settlement filing. The NEB has scheduled public hearings on the TransCanada Settlement to commence on September 9, 2014.

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

A. Yes. The forecasted TransCanada rates reflect TransCanada's Settlement with the Canadian LDCs, which would take effect on January 1, 2015.

Q. Does this conclude your testimony?

A. Yes it does.