NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2013
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 Factor (“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. Northern projects combined sales service and transportation-only distribution deliveries for the New Hampshire Division for the 2013 Summer Period to be 2,161,298 Dth, which is 5.7% higher than the 2012 Summer Period weather-normalized distribution deliveries and 8.4% higher than the 2011 Summer Period weather-normalized distribution deliveries. Of the 2,161,298 Dth of projected distribution system deliveries, Northern projects that 762,591 Dth will be supplied by the Company through Sales Service. In order to supply 762,591 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 767,476 Dth. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern has the ability to deliver up to 116,143 Dth of contract supply and on-system peaking capacity per day during the peak winter months, November through March and 36,815 Dth per day during the months of April through October. Northern's contract supply sources include Chicago, Lewiston, ME baseload supply, Tennessee Zone 6 Baseload, PNGTS, Niagara, Tennessee Production, Algonquin Receipts, Tennessee Firm Storage, Washington 10 Storage and Peaking Supplies. 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 2012 through October 2013 gas year to be $37,413,294. (*See* Schedule 5A). Mr. Chris Kahl, who is employed by Unitil Service Corp. as a Senior Regulatory Analyst II, 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 Summer COG rate. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $4,618,096. (*See* Schedule 5B).

I project that Northern's total company (including the New Hampshire Division) commodity cost to provide sales service during the 2013 Summer Period will be $5,657,572 at an average rate of $3.833 per Dth. (*See* Schedules 2 and 6A). I also calculated the impact of the hedging program on total company commodity costs of a loss of $3,190 based on NYMEX prices as of February 28, 2013. (*See* Schedule 7). Mr. Kahl calculates the portion of these costs, which are allocated to the New Hampshire Division.

Next, I present Northern's proposed hedging plan for the period beginning May 2013 through April 2014. The proposed hedging plan is consistent with the hedging program, approved by the Commission on March 30, 2010 in Docket No. DG 09-141. Supporting information concerning the proposed hedging plan can be found in Schedule 20.

Finally, I provide updates to the various pipeline rate cases affecting Northern. Northern is currently involved in the major pipeline rate cases on Portland Natural Gas Transmission System and TransCanada Pipelines Limited.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution 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: use-per-meter and the number of meters. The growth rates for customers (meters) and use-per-meter from these models are applied to the most recent data normalized for weather; the forecast monthly billed deliveries for each customer class was calculated by multiplying forecast customers times forecast use-per-customer. Forecast deliveries for the large commercial customers with special contracts were developed separately for each of these customers.

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 2013 Summer Period.

Table 1. 2013 Summer New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years							
Month	2013 Forecast[1]	2012 Actual[2]	2013 minus 2012	Percent Change	2011 Actual[2]	2013 minus 2011	Percent Change
May	484,431	429,260	55,171	12.9%	450,511	33,920	7.5%
Jun	354,205	348,153	6,053	1.7%	340,672	13,533	4.0%
Jul	286,323	300,179	-13,855	-4.6%	277,859	8,465	3.0%
Aug	297,936	302,241	-4,305	-1.4%	277,161	20,775	7.5%
Sep	314,137	303,338	10,799	3.6%	305,657	8,480	2.8%
Oct	424,265	361,315	62,950	17.4%	342,200	82,065	24.0%
Winter	2,161,298	2,044,485	116,812	5.7%	1,994,060	167,238	8.4%

Note 1: Company Forecast.
Notes 2 and 3: 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 2013 Summer Period in Attachment 1 to Schedule 10B. Page 1 of Attachment 1 to Schedule 10B 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 2013 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2012 and 2011 Summer 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. Please provide an overview of the process for converting the forecast distribution deliveries forecast to a sales service deliveries forecast.

A. In order to prepare this COG filing, Northern reduced its total distribution deliveries forecast to reflect only the distribution deliveries to those customers taking sales service. My commodity cost forecast, which I present later, reflects only the projected costs to serve Northern's sales service obligations. Customers electing transportation-only service reflect a substantial portion of Northern's total distribution deliveries, and the cost of gas for these customers is determined by the private contractual arrangements between the customers and their retail marketer.

Northern estimated the percentage of total distribution deliveries to be supplied through Sales Service ("Sales Service Percentage") for each rate class based upon the most recent 12 months of historical distribution and sales service deliveries data available at the time of the analysis.

I converted the billed distribution deliveries forecast to a calendar-month distribution deliveries forecast by calculating a five-year average ratio of monthly sendout to seasonal sendout and applying these monthly ratios to the forecast billed deliveries. In the case of G52 and Special Contracts, the bill month is the calendar month, so I made no adjustments to these rate classes. Then, I calculated the city-gate supply required to serve the Sales Service deliveries.

Attachment 2 to Schedule 10B provides my back-up calculations for this analysis. On Pages 1 and 2 of Attachment 2 to Schedule 10B, I present my calculation of the calendar month and billed sales service deliveries by rate class, using the methodology I discuss above. 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 forecasted 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"). 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.

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 and City-Gate Receipts to meet the Sales

Service Deliveries[1] for the upcoming Summer Period. The detailed calculations can be found in Attachment 2 to Schedule 10B.

Table 2. Required City-Gate Receipts Summary			
Month	Total Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
May-13	392,057	139,553	140,446
Jun-13	328,841	110,963	111,677
Jul-13	313,791	106,624	107,309
Aug-13	330,594	110,050	110,758
Sep-13	346,350	118,984	119,748
Oct-13	449,665	176,418	177,538
Summer	2,161,298	762,591	767,476

III. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its sales customers.

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

[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.

Table 3. Northern Capacity by Supply Source (Dth per Day)		
Supply Source	2012-2013 Winter	2013 Summer
Chicago Path	6,434	6,434
Lewiston Baseload	5,500	0
Tennessee Zone 6 Delivered Baseload	4,983	0
PNGTS Year-Round	1,096	1,096
Tennessee Niagara	2,331	2,331
Tennessee Long-Haul	13,109	13,109
Algonquin Receipt Points	1,251	1,251
Tennessee FS-MA & 5265	2,644	2,644
Washington 10 Path	32,885	0
Peaking Supply 1	9,983	0
Peaking Supply 2	5,000	0
Peaking Supply 3	4,983	0
Peaking Supply 4	15,944	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**116,143**	**36,865**

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 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 four separate peaking supply agreements, each providing Northern the option to purchase supply delivered to Tennessee Zone 6, PNGTS or Maritimes meters. These peaking supply arrangements were procured through a Request-For-Proposals and are for one winter in duration. 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 plans to replace its current LNG Contract (which ends 10/31/2013) in order to supply this facility. These Peaking Supply contracts will not be available during the 2013 Summer Period. 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 terms 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 requests-for-proposal ("RFP") for terms beginning April 1 and running through March 31 each year. Northern is in the process of completing its annual RFP for the delivery period beginning April 1, 2013 through March 31, 2014. This RFP sought asset management proposals for Northern's Chicago, Algonquin Receipts, Niagara, Tennessee Production and Washington 10 capacity paths. Northern also sought baseload supply through this RFP. The Company typically enters into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers. This summer, Northern plans to issue an RFP for replacement peaking supplies.

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 2013 Summer 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 2012 through October 2013
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2012 through October 2013
- Northern's commodity costs for the period May 2013 through October 2013
- Gains and losses due to Northern's financial hedging program for the period May 2013 through October 2013

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 New Hampshire and Maine 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, 2012 through October 31, 2013

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 9,964,773	Att NUI-FXW-4, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 26,827,274	Att NUI-FXW-4, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,035,662	Att NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,728,786	Att NUI-FXW-4, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 880,250	Att NUI-FXW-4, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (5,023,450)	Att NUI-FXW-4, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 37,413,294	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 5. 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 2012-2013 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. 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 2012-2013 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $4,618,096.

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 2013 Summer Period.

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

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2013 through October 2013

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	$1,542,326	405,092	$3.807
Tennessee Production	$3,374,038	886,129	$3.808
Algonquin Receipts	$259,521	67,000	$3.873
Chicago	$426,425	106,159	$4.017
PNGTS	$10,563	2,572	$4.107
TGP Zone 6	$2,707	656	$4.126
LNG	$41,993	8,280	$5.072
Total Delivered Commodity Cost	$5,657,572	1,475,889	$3.833

In summary, projected delivered commodity costs equal approximately $5.7 million at an average delivered rate of $3.833 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. Please provide the Company's monthly projections of storage inventory balances for the period November 2012 through October 2013.

A. Please refer to Attachment NUI-FXW-8. These results are based upon the Company's Sendout® analysis, which I provided to Mr. Kahl, and are the basis for his calculations in Attachment NUI-CAK-7.

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

A. I have calculated the unrealized gains or losses of the NYMEX natural gas futures contracts purchased by the Company in accordance with its hedging program. Based upon the February 28, 2013 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $3,190 for hedges for the upcoming Summer season. Please refer to Schedule 7 for the monthly hedging calculations.

V. NORTHERN HEDGING PLAN FOR NOVEMBER 2014 THROUGH APRIL 2015

Q. Has Northern developed a plan for hedging the period of May 2013 through April 2014?

A. Yes. The initial schedule for the hedging plan for the twelve-month period beginning May 2014 is attached as Schedule 20, page 1 of 3. The initial schedule plan lists the planned purchases of futures contracts for the contract months being hedged as well as placeholders for the price ceiling for each of those months. In accordance with Northern's hedging program, approved by the Commission on March 30, 2010 in Docket No. DG 09-141, so long as prices are below the respective price ceiling for each contract month, purchases will be made as scheduled each month on the expiration date of the prompt month contract. The price ceiling values will be updated in mid-April to reflect more recent prices that will determine the price ceiling values for the twelve-month period beginning May 2014.

Q. Has Northern provided a three-year schedule of projected hedging activity in accordance with the revised hedging program?

A. Yes. Schedule 20, page 2 of 3 provides a three-year projection of sendout requirements, the peak season resources expected to provide fixed pricing and the financial hedging volumes required to meet the fixed price targets under the hedging program, which are 40 percent of requirements for May and October and 70 percent of requirements for the peak season. As shown on page 2, the plan calls for 177 contracts for the twelve month period beginning May 2014, 185 contracts for the period beginning May 2015, and 186 contracts for the period beginning May 2016.

Q. Is Northern recommending any adjustments to the hedging plan for the period of May 2013 through April 2014?

A. No. For the period May 2013 through April 2014, Northern has procured futures contracts in accordance with the hedging program, approved by the Commission in Docket No. DG 09-141 and the hedging plan, provided to the Commission in Docket No. DG 12-068, the 2012 Summer COG. Attachment NUI-FXW-11, page 3 of 3 presents the current status of the hedge plans for the 2013 Summer and 2013-14 Winter periods with regard to the percentage of sendout requirements expected to be available under fixed prices given physical hedges and the purchases of futures contracts already completed. As shown on Schedule 20, page 3, the projected percentage hedged for both the 2013 Summer and the 2013-2014 Winter Periods are within 5% tolerance of the target hedged positions, so Northern does not recommend any changes to the hedge plans for the these periods.

Q. Has Northern made proposals to change the design of its hedging program in the Maine Division?

A. Yes. In Maine Public Utilities Commission Docket No. 2012-00448, Northern has been engaged with the Commission's Advisory Staff and the Office of the Public Advocate in the development of a proposal to modify the hedging program for the Maine Division. If this process leads to a new hedging program design for the Maine Division, Northern anticipates initial implementation would begin in late April 2013 with a hedging plan for the winter period of November 2014 to March 2015. If the recommendations under review in Docket 2012-00448 do not lead to changes in the hedging program, Northern would continue to operate the program under the current program design.

As currently conceived, the new program would replace the purchase of futures contracts with the purchase of out of the money options on futures contracts. Northern would revise its hedging plan for the New Hampshire Division such that the planned purchase of NYMEX futures contracts would be based only upon the sendout forecast for the New Hampshire Division.

VI. 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 has filed rate cases under FERC Docket Nos. RP08-306 ("2008 PNGTS Rate Case") and RP10-729 ("2010 PNGTS Rate Case").
- TransCanada Pipelines Limited has filed an application with the NEB on September 1, 2011, which proposes to restructure its business and services and establish final tolls for 2012 and 2013 ("2012 and 2013 TransCanada Tolls Application").

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

A. The Initial Decision of the Administrative Law Judge in the 2008 Rate Case was issued on December 24, 2009 and on February 17, 2011 the FERC issued its Opinion and Order on the Initial Decision ("Opinion 510"). The Initial Decision ruled on significant rate-making issues including treatment of bankruptcy revenues, capacity for purposes of rate-making, return on equity, the treatment of interruptible transportation revenues, negative salvage rate, depreciation rates, and type of cost levelization model. Opinion 510 affirmed the Initial Decision with modifications and ordered PNGTS to file revised tariff sheets in compliance with Opinion 510. Numerous parties to the 2008 PNGTS Rate Case have filed requests for rehearing, including both the Portland Shippers Group ("PSG") and PNGTS. Northern is participating in both the 2008 and 2010 PNGTS Rate

Cases as a member of the PSG. Northern continues to await FERC action on the 2008 PNGTS Rate Case.

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

A. On May 12, 2010, PNGTS filed a new rate case which was docketed RP10-729. The proposed rates represent a 47 percent increase over prior rates. Northern intervened in opposition as a member of PSG. The proposed rates went into effect on December 1, 2010, subject to refund. Settlement discussions were unsuccessful and a hearing was held from April 27, 2011 through May 25, 2011. Initial briefs were filed June 6, 2011 and reply briefs were filed August 8, 2011. The Administrative Law Judge issued an Initial Decision in the 2010 PNGTS Rate Case on December 8, 2011. Although the Initial Decision found in favor of PNGTS on several key issues, Northern believes that the Initial Decision in the 2010 PNGTS Rate Case supports a lower rate than was proposed, if it is approved by the FERC. However, Northern, through the PSG, disagrees and opposes the 2010 PNGTS Rate Case Initial Decision in several material respects, the most significant of which is the capacity for purposes of rate-making. On February 1, 2012, the parties filed Briefs on Exceptions to this Initial Decision. Briefs Opposing Exceptions were filed by both PSG and PNGTS on March 7, 2012. Northern awaits final FERC action on the 2010 PNGTS Rate Case.

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. Please provide an update of the 2012 and 2013 TransCanada Tolls Application.

A. On September 1, 2011, TransCanada filed the 2012 and 2013 TransCanada Tolls Application. In its Tolls Application, in addition to the general level of tolls, TransCanada made the following primary proposals of concern to Northern. TransCanada proposed to modify the calculation of depreciation expense, to include portions of its natural gas gathering system in western Canada for rate purposes, and to modify its toll design by increasing the allocation of costs to short-haul contracts, by carving out Trans Québec & Maritimes ("TQM") costs and assigning these costs only to customers taking delivery at TQM points, and by socializing delivery pressure tolls. TransCanada also proposed to raise bid floors for the sale of short-term discretionary service. Northern was represented in the tolls application proceeding as a member of Alberta Northeast Energy Limited ("ANE"). Final Arguments were heard by the NEB in November 2012 and a decision in the TransCanada Tolls Application is expected during the first quarter 2013.

Q. Are the impacts of the TransCanada Tolls Application reflected in the proposed COG?

A. Yes. The forecasted TransCanada rates reflect TransCanada's approved 2012 Interim Tolls.

Q. Does this conclude your testimony?

A. Yes it does.