Prefiled Testimony of Francis X. Wells

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
2011 SUMMER PERIOD
COST OF GAS 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 Gas Supply. 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 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. What is the purpose of your prefiled testimony in this proceeding?

A. The purpose of my prefiled testimony is to describe and explain the forecast of gas demand and the resulting forecasted gas sendout and gas costs that were used to calculate of the 2011 Summer COG rate adjustments for Northern's New Hampshire Division. My prefiled testimony also describes the impact of the Company's Hedging Program for the 2011 Summer period.

Q. Please summarize your prefiled testimony in this proceeding.

A. Northern projects combined sales service and transportation-only distribution deliveries for the New Hampshire Division for the 2011 Summer Period to be 2,020,593 Dth, which is 1.4% higher than 2010 Summer Period weather-normalized distribution deliveries and 3.6% higher than 2009 Summer Period weather-normalized distribution deliveries. Of the 2,020,593 Dth of projected distribution system deliveries, Northern projects that 740,064 Dth will be supplied by the Company through Sales Service. In order to supply 740,064 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 748,568 Dth. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern has the ability to deliver a maximum of 131,460 Dth of supply per day during the peak winter months, November through March, and 41,512 Dth of supply per day during the months of April through October. Northern's supply sources include Chicago, PNGTS, Niagara, Tennessee Production Area, Washington 10 Storage, Tennessee Firm Storage, Peaking Supplies and an LNG Facility in Lewiston, Maine. The details behind

Northern's portfolio are contained in Schedule 12. Northern has recently made some contract changes, which are expected to result in an annual savings of $70,000 for the benefit of Northern's customers.

Northern updates its demand cost and capacity assignment demand revenue once per year with the Winter COG filing. I include the supporting calculations to these projections in the 2011 Summer COG filing for completeness. I projected Northern's total company (including the Maine Division) demand cost for the November 2010 through October 2011 gas year to be $36,218,638. (Schedule 5A). Mr. James Simpson from Concentric Energy Associates calculated the portion of this annual total that was allocated to Northern's New Hampshire Division, and the portion of that allocation to be recovered in the Summer COG rate. I also projected the demand revenue from New Hampshire's capacity assignment program to be $2,600,137. (Schedule 5B).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2011 Summer Period will be $7,140,953 at an average rate of $5.1634 per Dth. (Schedules 2 and 6A). I also calculated the impact of the hedging program on total company commodity costs of a loss of $7,460, based on NYMEX prices as of January 20, 2011. (Schedule 7). In order to update the COG rate calculation to better reflect market changes since January 20, 2011, I provided NYMEX settlement prices as of March 1, 2011, which I provided to Mr. Simpson for the purpose of adjusting the proposed COG rate to account for changes in NYMEX pricing. Mr. Simpson also calculates the portion of these forecast gas supply costs, which are allocated to the New Hampshire Division.

I provide the plan for Northern's financial hedging activity for the period beginning May 2012 through April 2013 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 regarding Portland Natural Gas Transmission System and Tennessee Gas Pipeline Company. In addition, TransCanada Pipelines Limited has proposed toll increases and also seeks to restructure its rate design. Lastly, a final order has been issued by the FERC in the Granite State Gas Transmission rate case. Due to the magnitude of the increases in rates sought by the various pipelines on which Northern holds long-term capacity contracts, Northern anticipates increased activity at both the FERC and the Canadian NEB through various shippers' groups to which Northern belongs in order to pursue the best interests of Northern's customers.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries[1] 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

[1] In my testimony I use the term "deliveries" to refer to the volumes or quantities of gas that are distributed to the premises of sales customers and transportation customers. I use the term "sales customer" to refer to a gas customer that receives bundled distribution and gas supply service from Northern. I use the term "transportation customer" to refer to a gas customer that receives distribution service from Northern and gas supply service from a competitive retail supplier.

customers with special contracts were developed separately for each of these customers.[2]

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 2011 Summer Period.

Table 1. 2011 Off-Peak New Hampshire Division Metered Distribution Service Deliveries Forecast Compared to Prior Years

Month	2011 Forecast*	2010 Actual**	2011 minus 2010	Percent Change	2009 Actual**	2011 minus 2009	Percent Change
May	429,234	419,968	9,267	2.21%	437,655	-8,420	-1.92%
Jun	349,143	332,756	16,388	4.92%	317,236	31,907	10.06%
Jul	284,277	280,688	3,589	1.28%	279,336	4,941	1.77%
Aug	281,167	286,046	-4,879	-1.71%	268,980	12,187	4.53%
Sep	300,274	300,569	-294	-0.10%	284,834	15,440	5.42%
Oct	376,496	371,838	4,658	1.25%	362,059	14,438	3.99%
Off-Peak	2,020,593	1,991,863	28,729	1.44%	1,950,100	70,492	3.61%

* Company Forecast.
** 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 2011 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

[2] When forecasting the Large General rate classes (G42 & T42, G52 & T52 and Special Contracts), the Company utilizes individual customer forecasts through the first full calendar year of the forecast. Thereafter, the Company relies on its forecast of use-per-meter and the number of meters for each rate class. Since this COG filing relies solely on forecast data within the first calendar year, the Large General forecast is based on the individual forecasts.

classes, heating residential rate classes and commercial and industrial rate classes, respectively. The top section of each page provides the 2011 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2010 and 2009 Summer Periods. The changes in the distribution deliveries from the prior period are explained 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; however the cost of gas for these customers is determined by the private contractual arrangements between the customers and their retail marketer.

I 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 utilizing the same model used by the Company to develop the billed distribution deliveries forecast. Using this model, I replaced the projected bill cycle data for monthly days and effective degree days with calendar month days and effective degree days. For each rate class, I multiplied the projected Sales Service Percentage by the projected calendar-month distribution deliveries forecast to calculate the sales service deliveries forecast. Having converted the billed distribution service deliveries to calendar month Sales Service deliveries, I then 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. I also present annual summary data of projected Migration to Transportation Only Service by Rate class in Schedule 13.

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 Calendar Month Distribution 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.

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[3] for the upcoming Peak 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-11	383,221	164,519	166,206
Jun-11	308,155	104,668	105,914
Jul-11	279,541	82,572	83,503
Aug-11	285,914	94,844	96,012
Sep-11	329,429	113,688	115,113
Oct-11	447,305	179,773	181,820
Summer	2,033,565	740,064	748,568

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

[3] 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, Maritimes and Northeast, L.L.C and Tennessee Gas Pipeline and the Company's LNG facility.

contracts, storage contracts, peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table 3. Northern Capacity by Source of Supply (Dth per Day)

Supply Source:	Northern Deliverable Winter Capacity (Nov - Mar)	Northern Deliverable Summer Capacity (Apr-Oct)
Chicago (Interconnection of Alliance and Vector Pipelines)	6,433	6,433
Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)	1,095	1,095
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,280	3,280
Tennessee Production Area	13,089	13,089
Washington 10 Storage	32,835	0
Tennessee Firm Storage - Market Area	2,640	2,640
Peaking Supply 1	4,975	4,975
Peaking Supply 2	57,113	0
Lewiston LNG Facility	10,000	10,000
Total Deliverable Capacity	131,460	41,512

I have prepared a capacity path diagram and capacity path detail for each of the supply sources listed above (except the Lewiston LNG, which feeds directly into Northern’s distribution system), 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, as well as long-term peaking supply contracts, Distrigas of Massachusetts Corporation ("Peaking Supplier 1") and FPL Energy Power Marketing, Inc. ("Peaking Supplier 2"). 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"). 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.

I have prepared the capacity path diagrams and capacity path details in Schedule 12 in order to 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. The Company has found that some of its Algonquin and Texas Eastern transportation contracts were not highly utilized by Northern, but were highly valued in the market-place. Effective May 1, 2009, Northern permanently released the Algonquin and Texas Eastern contracts contributing to the majority of costs for the capacity paths, listed in Table 4, below.[4] These releases are at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contracts. As a result, capacity from these supply sources is no longer deliverable. Pages 9 and 10 of Schedule 12 also contain capacity path diagrams and capacity path details of these released capacity paths in order to provide a complete picture of the portfolio.

Table 4. Released Capacity

Supply Source:	Northern Deliverable Capacity (Dth per Day)
Texas Eastern Production and Storage & Algonquin (Centerville, NJ)	286
Texas Eastern Zone M3	965
Total Released Capacity	1,251

[4] Northern has the right to a single recall of its permanent releases of Algonquin contract number 93201A1C and Texas Eastern contract number 800384.

Q. What updates have been made to Northern's capacity portfolio since the last COG filing?

A. Effective November 1, 2010, Northern recalled a transportation capacity contract with Union, which Northern had previously assigned to TransCanada and amended its transportation contract with TransCanada.

Q. Please provide an overview of the circumstances surrounding these contract changes.

A. On February 25, 2006, Northern entered into a transportation contract with Union Gas ("Union Transportation Contract") for 6,333 GJ of capacity from Dawn to Parkway for a term beginning November 1, 2006 and ending October 31, 2017. On April 10, 2006, Northern had entered into a transportation contract with TransCanada ("TransCanada Transportation Contract") for 6,264 GJ of capacity from Parkway to Iroquois Pipeline for a term also beginning November 1, 2006 and ending October 31, 2007. These contracts are part of Northern's Chicago capacity path, moving supplies from Vector to Iroquois pipelines. Northern entered into these contracts (and all other transactions discussed in this response) as members of Alberta Northeast Gas, Limited. ("ANE") ANE represents a consortium of 17 local gas distribution utilities in the Northeastern United States. Effective November 1, 2007, Northern assigned the Union Transportation Contract to TransCanada and amended the TransCanada Transportation Contract to provide 6,264 GJ of transportation capacity from Dawn to Iroquois. The general purpose of the November 1, 2007 contract changes was administrative efficiency; moving gas from Dawn to Iroquois required only a single pipeline nomination with TransCanada when the two contracts were merged. It had been represented that there would be little or no cost impact from the November 1, 2007 contract changes. However, this has not been the case, as demand costs on the amended TransCanada Transportation Contract have been significantly higher than those that would have been incurred had the contract changes not been made. Effective November 1, 2010, Northern recalled its Union Transportation Contract and amended the TransCanada Transportation Contract to its original terms. The advantage to Northern's customers for this change is lower demand costs. Based on rates in effect when the change became effective, the TransCanada annual demand charge for 6,264 GJ of Dawn to Waddington capacity is estimated to be approximately $830,000. Based on the current rates, the demand charges for the new contracts are estimated to be approximately $760,000, a savings of $70,000.

Q. Are these savings reflected in the proposed COG calculation?

A. No. This contract change was not known at the time of the Winter COG calculation when the demand cost forecast is annually updated. The savings will be reflected when Northern files its reconciliation of the 2010-2011 Winter COG.

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

A. Northern's practice is to secure its gas supply commodities through annual requests-for-proposal ("RFP") for terms beginning April 1 and running through March 31 each year. Northern has issued an RFP for its summer re-fill of underground storage and projected baseload supplies through March 2012. The Company typically enters into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers.

IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Simpson to calculate the 2011 Summer COG.

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

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities for the period November 2010 through October 2011
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2010 through October 2011
- Northern's commodity costs for the period May 2011 through October 2011
- Gains and losses due to Northern's financial hedging program for the period May 2011 through October 2011

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

Q. Are the Demand Cost Forecast and the Capacity Assignment Demand Revenues filed for this 2011 Summer COG the same as that which was filed in Docket No. DG10-250?

A. Yes. The Demand Cost Forecast and Capacity Assignment Demand Revenues are updated once annually as part of the Winter COG filing. I have provided these estimates with the Summer COG filing in order to provide complete information.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 5, below, titled, "Summary of Estimated Fixed Demand Costs."

Table 5. Summary of Estimated Fixed Demand Costs November 1, 2010 through October 31, 2011			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 6,979,327	Schedule 5A, Page 2 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 23,000,956	Schedule 5A, Page 2 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,008,911	Schedule 5A, Page 3 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,578,485	Schedule 5A, Page 2 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 4,582,488	Schedule 5A, Page 4, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (2,931,530)	Schedule 5A, Page 5 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 36,218,638	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 5A. On page 1 of Schedule 5A, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 2 of Schedule 5A, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 3 and 4 of Schedule 5A provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 5 of Schedule 5A, I forecast the capacity release and asset management revenue the Company expects to receive for the 2010-2011 Gas Year.

Support for the transportation and storage rates used in Schedule 5A are found in the Attachment to Schedule 5A.

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 2010-2011 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,600,137.

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 2011 Summer Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Summer Period in Table 6, below. This information is also provided in Schedule 2 of the filing. Please note that this commodity cost forecast is based upon NYMEX natural gas settlement prices as of January 20, 2011.

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes			
May 2011 through October 2011			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Chicago	$4,855,157	943,562	$5.1456
PNGTS	$736,769	142,882	$5.1565
Tennessee Production	$814,815	156,831	$5.1955
Niagara	$688,111	131,446	$5.2349
LNG	$46,100	8,280	$5.5677
Total System	$7,140,953	1,383,001	$5.1634

In summary, projected delivered commodity costs equal approximately $7.1 million at an average delivered rate of approximately $5.16 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 for the supply prices and variable transportation charges found in Schedule 6B are found in the Attachment to Schedule 6B.

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

A. Please refer to Schedule 11 for this information. Schedule 11A provides Normal Year Sendout Volumes for the upcoming 2011 Summer Period. Schedule 11C presents the capacity utilization factors by resource, which is calculated by dividing total period sendout by the maximum available volume for the period. Schedules 11B and 11D refer to design cold winter conditions, and will be provided again in the 2011-2012 Winter COG filing.

Q. Has Northern adjusted the commodity cost forecast in the proposed COG rate calculations for the changes in NYMEX natural gas prices since January 20, 2011?

A. Yes. I provided Mr. Simpson with updated NYMEX natural gas prices, reflecting the settlement for March 1, 2011. Mr. Simpson used these updated NYMEX natural gas prices to revise the expected commodity costs in the proposed COG rates. Table 7, below, provides a comparison of the NYMEX prices used in the original commodity cost estimate and those used to update the COG rate model in preparation for this filing.

Table 7. NYMEX Price Comparison							
Settlement Date	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Average
1/20/2011	$4.707	$4.739	$4.791	$4.816	$4.821	$4.869	$4.791
3/1/2011	$3.950	$4.015	$4.084	$4.116	$4.128	$4.176	$4.078

Q. Please provide the Company's monthly projections of storage inventory balances for the period May 2011 through October 2011.

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

Q. Please provide the impact of the hedging program on the Company's proposed COG rates.

A. I have calculated the unrealized gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program. Based upon the January 20, 2011 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $7,460 for hedges for the coming summer season. Please refer to Schedule 7 for the monthly hedging calculations. Since January 20, 2011, the NYMEX prices have declined substantially, resulting in higher projected hedging losses. The adjustment to the commodity forecast in the proposed COG rate accounts for the change in hedging losses due to changes in price. Based upon March 1, 2011 NYMEX settlement prices and program purchases made since January 20, 2011, hedging losses are projected to be approximately $185,000.

V. NORTHERN HEDGING PLAN FOR MAY 2012 THROUGH APRIL 2013

Q. Has Northern developed a plan for hedging the period of May 2012 through April 2013?

A. Yes. The initial schedule for the hedging plan for the twelve-month period beginning May 2012 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 a price ceiling for each of those months. In accordance with the revised hedging proposal, 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 shown are preliminary, and therefore Schedule 20, page 1 of 3 will be updated in mid-April to reflect final price ceiling values.

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 revised hedging proposal, 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 150 contracts for the twelve month period beginning May 2012, 167 contracts for the period beginning May 2013, and 183 contracts for the period beginning May 2014.

Q. Do the proposed changes to the hedging program impact hedging plans for periods prior to May 2012?

A. No. Schedule 20, page 3 of 3 presents the current status of the hedge plans for the summer 2011 and winter 2011-12 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 of May and October hedged is 46%, compared to the target of 40%. As shown on Schedule 20, page 3, 67% of peak season requirements are expected to be available under a fixed price, compared to the target of 70%. These variances are within an acceptable range of the target hedged positions, so Northern does not recommend any changes to the hedge plans for the summer 2011 and winter 2011-12 periods.

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 in FERC Docket Nos. RP08-306 (“2008 PNGTS Rate Case”) and RP10-729 (“2010 PNGTS Rate Case”).
- Tennessee Gas Pipeline Company has filed a rate case in FERC Docket No. RP11-1566 (“Tennessee Rate Case”).
- TransCanada Pipelines Limited has filed an application to the Canadian National Energy Board for new tolls (“TransCanada Tolls Application”).
- Granite State Gas Transmission, Inc. has filed a rate case in FERC Docket No. RP10-896 (“Granite Rate Case”).

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 has 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 the at-risk condition, 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.

Q. What is the impact of FERC's Order in 2008 PNGTS Rate Case, should it ultimately be upheld?

A. PNGTS rates from September 2008 through November 2010 were billed subject to refund at the rate proposed in the 2008 PNGTS Rate Case. The tariff sheets PNGTS files pursuant to the Opinion 510 will define the PNGTS rates applicable to this period. Such rates will be subject to the refund floor for the purposes of refunds, and refunds would be due within 30 days of a final order from FERC. PNGTS must file revised tariff sheets and rates within 30 days of Opinion 510, or by March 19. However, Opinion 510 is subject to requests for rehearing on specific issues, which are also due from the multiple parties within 30 days from the issuance of the Order. The Portland Shipper Group ("PSG") has indicated its intent to request rehearing on specific issues. At this time it is not clear how extensive requests for rehearing will be, or how long it will take until a final order is issued. Should the final order from FERC uphold the Initial Decision in RP08-306, Northern estimates a refund of approximately $1.2M dollars, $600,000 of which would be credited to the New Hampshire Division.

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

A. On May 12, 2010, PNGTS filed a new rate case which has been docketed RP10-729. The proposed new rates represent a 47 percent increase over current rates. Northern has intervened as a member of PSG. On June 11, 2010, FERC ordered suspension of the proposed new rates until December 1, 2010, when they went into effect (subject to refund). Settlement discussions were unsuccessful and the proceeding is headed to hearing. Staff and intervener direct and answering testimony was submitted on January 19, 2011. Staff and intervener cross answering testimony and PNGTS answering testimony was due February 17, 2011. Rebuttal testimony from all parties is due March 24, 2011 and the case is set for hearing on April 27, 2011.

Q. Does the proposed COG reflect the rate increases proposed in the 2008 PNGTS Rate Case and 2010 PNGTS Rate Cases?

A. Yes. The demand cost forecast provided to the Commission as part of the 2010-11 Winter COG Filing reflected the rates proposed by PNGTS in the 2008 PNGTS Rate Case through November 2010 and the rates proposed by PNGTS in the 2010 PNGTS Rate Case beginning December 2010. The demand cost forecast also reflects the refund that would be due Northern should the FERC uphold the Initial Decision in the 2008 PNGTS Rate Case. I present Northern’s estimate of this refund in Schedule 5C. This projected refund is offset by Northern’s litigation expenses incurred, which I present in Schedule 5D. Each of these schedules was included in the 2010-2011 Winter COG filing.

Q. Please provide an update on the Tennessee Rate Case.

A. On November 30, 2010, Tennessee filed a rate case, which has been docketed as RP11-1566. The proposed new demand rates represent a 100% percent increase over current demand rates, as Tennessee proposes to change its rate design in two respects. First, Tennessee proposes to recover all fixed costs through the demand charge, while the current rate design provides for recovery of approximately 15% of fixed costs through the usage charge. The proposed usage charges reflect only variable costs for service. Second, Tennessee proposes to increase short-haul rates relative to long-haul rates. This proposal is driven by a decrease in subscription for long-haul service due to the increase in supply in the Northeast, resulting primarily from Marcellus shale production and the interconnection with Rockies Express. The proposed new tariff also contains non-rate issues, including an inventory cycling requirement for firm storage capacity holders. The FERC has set a Technical Conference for February 2, 2011 to discuss non-rate issues proposed in the filing. Northern has intervened as a member of the New England Tennessee Shippers Group. On December 29, 2010, FERC ordered the suspension of the proposed new rates until June 1, 2011, when they go into effect subject to refund. Due to the complexity of the issues involved in the Tennessee Rate Case (including the fact that current rates have been in place since 1995), the procedural schedule in the Tennessee Rate Case sets June 12, 2012 as the date for the Initial Decision from the Administrative Law Judge. There are also likely to be lengthy and involved settlement discussions as part of the Tennessee Rate Case.

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

A. No. The Tennessee Rate Case was not yet filed when I prepared the demand cost forecast for the 2010-2011 Peak COG. The Tennessee Rate Case will impact future COG rates.

Q. Please provide an update on the TransCanada Tolls Application.

A. On December 9, 2010, TransCanada applied to the Canadian National Energy Board ("NEB") for increased tolls on an interim basis and a proposed restructuring of its rate design. The TransCanada Tolls Application reflected a settlement agreement between TransCanada and the Canadian Association of Petroleum Producers, which proposed to permanently shift costs from long-haul capacity to short-haul capacity in return for a temporary decrease in revenue requirement. On December 16, 2010, Alberta Northeast Gas Limited ("ANE"), of which Northern and 16 other local distribution companies in the Northeastern U.S. are members, filed a letter opposing the toll application on the grounds that the shift in costs from long-haul capacity to short-haul capacity would significantly increase rates for our long-term contracts as soon as the temporary revenue requirement decreases were no longer in effect. Other short-haul shippers filed comments in opposition as well. On December 23, 2010, the NEB rejected the proposed interim tolls application and set the 2011 tolls at the current rates on an interim basis. On January 25, 2011, TransCanada filed a new application for interim tolls, which reflects a 40% increase over the 2010 tolls.

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

A. No. The TransCanada Tolls Application was not yet filed when I prepared the demand cost forecast for the 2010-2011 Peak COG. The TransCanada Tolls Application will impact future COG rates.

Q. Please provide an update on the Granite Rate Case.

A. On June 29, 2010, Granite filed a rate case, which was docketed as RP10-896. On July 30, 2010, FERC ordered the suspension of the proposed demand rate until January 1, 2011, subject to refund. On November 30, 2010, a settlement was filed with the FERC in the Granite Rate Case. The settlement agreement reflects a demand rate of $2.80 per Dth compared to the previously effective demand rate of $1.666 per Dth. On January 31, 2011, FERC is issued a final order in the Granite Rate Case, approving the settlement filed on November 30, 2010.

Q. Are the impacts of the Granite settlement reflected in Northern's COG rates?

A. Yes. The demand cost forecast used in the Winter COG fling reflect the previously effective demand rate of $1.666 per Dth for the period of November 2010 through December 2010, and the proposed rate of $3.518 for the period of January 2011 through October 2011. When the FERC approved the settlement rate of $2.80 per Dth, Northern began reflecting this expected savings to customers in the monthly Cost of Gas filings made to the Commission. The Granite settlement does not directly impact the proposed 2011 Summer COG rate because the demand cost allocated to the 2011 Summer period were determined in the 2010-2011 Winter COG rate filing. However, these cost savings have been reflected in Northern's determination of the current COG rates.

Q. Does this conclude your testimony?

A. Yes it does.