Prefiled Testimony of Francis X. Wells

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2010
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
FRANCIS X. WELLS

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Francis X. Wells. I am Senior Energy Trader for Unitil Service Corp. ("Unitil"). My business address is 6 Liberty Lane West, Hampton, NH.

Q. Please describe your relevant educational and work experience.

A. I received my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined Unitil in September 1996, assisting in the planning and operation of both electric power and natural gas supply portfolios. Since January 2001, I have worked as a Senior Energy Trader in the Energy Contracts Department. I have responsibilities in the areas of (1) energy supply acquisition, including natural gas supply procurement and electric default service purchasing; (2) regulatory testimony and reporting; (3) budgeting for both natural gas and electric supply; and (4) long-term supply planning.

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 explain the purpose of your prefiled direct testimony in this proceeding.

A. First, I will provide an overview of Northern's sales and sendout projections for the 2010 Summer Period Cost of Gas ("COG").

Second, I will provide a summary of Northern's natural gas supply portfolio which will be used to meet these supply requirements.

Next, I will provide a detailed forecast of the gas supply cost based on the sendout forecast and the natural gas supply portfolio. The gas supply cost forecast includes the following items:

- Fixed Demand Costs, including reservation and demand charges for supply contracts, transportation contracts and storage contracts that are part of Northern's wholesale portfolio of contracts and any projected offsets due to Northern's capacity assignment program or the optimization of Northern's portfolio through capacity release contracts or asset management contracts. The Fixed Demand Cost forecast is updated once annually for COG rates effective November 1 each year.

- Variable Commodity Costs, including any variable supply and transportation or storage charges to be incurred to deliver natural gas commodity to meet Northern's projected sendout requirements.

- Gains or Losses of Northern's Hedging Program

- Projected Storage Inventory costs and balances

I have provided these materials to James Simpson, Vice President of Concentric Energy Advisors, who used them as inputs to calculate the proposed COG rates.

I will also provide the Commission a hedging plan for the period of May 2011 through April 2012, and with updates to the hedging plans for the summer of 2010 and the winter of 2010-2011. Northern filed proposed modifications to the hedging program on August 7, 2009, in Docket DG 09-141. Through subsequent discovery and exchanges at technical conferences with the Staffs of both the New Hampshire and Maine Commissions, Northern believes there is a consensus on how the program should proceed. At the technical conference held on February 9, 2010, Northern agreed to provide the Commission with its most recently revised hedging plan as part of this Cost of Gas filing.

Finally, I will provide an update on the Company's ongoing litigation with the Portland Natural Gas Transmission System ("PNGTS"). The Commission granted Northern approval to recover PNGTS litigation expenses incurred from December 1, 2008 through August 31, 2009 in its 2009 / 2010 Winter COG rates, in Docket DG 09-167. Northern is not seeking recovery of PNGTS litigation expenses incurred since September 2009 in this Summer 2010 filing, but intends to seek full recovery of PNGTS litigation expenses incurred since September 2009 beginning with its 2010-2011 Winter COG filing, in a manner similar to the expenses approved by the Commission in DG 09-167[1].

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[1] Northern acknowledges that the Commission's order approving recovery of the PNGTS litigation expenses incurred from December 2008 through August 2009 in DG 09-167 did not set any precedent in regards to the treatment of future costs of this nature.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries[2] 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.[3]

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.

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[2] 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 who receives bundled distribution and gas supply service from Northern. Finally, I use the term "transportation customer" to refer to a gas customer who receives distribution service from Northern and gas supply service from a competitive retail supplier.

[3] 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.

Table 1. 2010 Summer New Hampshire Division Metered Deliveries Forecast Compared to Prior Years							
Month	2010[1]	2009[2]	Change over Prior Year	Percent Change	2008[3]	Change over Prior Year	Percent Change
May	432,762	437,655	-4,893	-1.12%	537,641	-104,879	-19.51%
Jun	342,189	317,236	24,952	7.87%	388,205	-46,017	-11.85%
Jul	284,559	281,438	3,121	1.11%	381,822	-97,263	-25.47%
Aug	270,037	266,995	3,042	1.14%	270,911	-874	-0.32%
Sep	310,686	307,587	3,099	1.01%	290,395	20,291	6.99%
Oct	352,562	349,364	3,199	0.92%	357,596	-5,034	-1.41%
Off-Peak	1,992,795	1,960,274	32,521	1.66%	2,226,571	-233,775	-10.50%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data.
Note 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 2010 Off-Peak Period in Attachment 1 to Schedule 10B. Page 1 of this Attachment 1 provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate classes, heating residential rate classes and commercial and industrial rate classes, respectively. The top section of each page provides the 2010 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2009 and 2008 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 calculations of the use-per-meter, which have been made using the distribution deliveries and meter count data presented in the top and middle sections of the page.

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

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 not reflected in this COG filing because such costs is determined by the private contractual arrangements between the customers and their retail marketers.

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[4].

Table 2. Required City-Gate Receipts Summary

Month	Total Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
May-10	432,762	232,685	232,872
Jun-10	342,189	156,509	166,077
Jul-10	284,559	109,067	105,222
Aug-10	270,037	96,763	103,049
Sep-10	310,686	116,545	108,369
Oct-10	352,562	136,291	142,055
Off-Peak	1,992,795	847,861	857,644

[4] 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 could be delivered either from the Company's interconnection with Granite State Gas Transmission, an affiliated pipeline, the Company's interconnection with the Maritimes and Northeast, LLC or the Company's LNG facility.

I have also prepared Attachment 2 to Schedule 10B, which provides the back-up calculations to this forecast. On Page 1 of Attachment 2, I present my calculation of the sales service deliveries by rate class. I calculated sales service deliveries by rate class by multiplying the 2010 forecast distribution deliveries and the Company's forecast of the ratio of sales service deliveries to total distribution deliveries for each 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 2 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 (provided in Attachment 1 to Schedule 10B) and the estimated ratio of Company-Use to Total Deliveries. Then, I added Company Use to the total Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use"). Finally, I multiplied the monthly Sales Service plus Company Use times the estimate of the monthly ratio of Receipts to Deliveries. Each of the ratios used in these calculations was based on recent historical actual data.

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.

Table 3. Northern Capacity by Source of Supply	
Supply Source:	Northern Deliverable Capacity (Dth per Day)
Chicago (Interconnection of Alliance and Vector Pipelines)	6,433
Empress, Alberta	1,095
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,280
Tennessee Production Area	13,089
*Washington 10 Storage	32,835
Tennessee Firm Storage - Market Area	2,640
Peaking Supply 1	4,975
*Peaking Supply 2	52,735
Lewiston, ME LNG Facility	10,000
Total Deliverable Capacity	127,081

* indicates that the capacity is deliverable only during the months of November through March.

I have 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, Transportation ("TransCanada"), Vector Pipeline L.P. ("Vector"), 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. Northern has permanently released the Algonquin and Texas Eastern contracts contributing to the majority of costs for the capacity paths, listed in Table 4, below.[5] 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 contains capacity path diagrams and capacity path details of these released capacity paths in order to provide a complete picture of the contracts, which Northern continues to seek the permanent release of.

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

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

A. Effective with the upcoming RFP, Northern's practice to secure its gas supply commodity supplies through annual requests-for-proposal ("RFP") for terms beginning April 1 through

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

March 31 each year. Northern plans to issue an RFP during the month of February 2010 for the purpose of procuring the supplies necessary to meet its projected requirements for the period beginning April 2010 through March 2011. These supplies include summer re-fill of underground storage and projected baseload supplies for the upcoming 12-month period. The Company plans to continue to utilize 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 2010 Off-Peak COG.

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

- The fixed demand cost forecast, including revenue offsets due to capacity release and asset management activities, which was used to calculate the 2009 / 2010 Peak COG.
- Projected New Hampshire Division Capacity Assignment program demand revenues.
- An updated commodity cost forecast for the 2010 Off-Peak Period.
- Estimated impact of Northern's financial hedging program for the 2010 Off-Peak Period.

Q. Please provide Northern's demand cost forecast.

A. This filing continues the demand cost forecast provided to the Commission for the 2009 / 2010 Peak COG filing. Please refer to Table 5, below, titled, "Summary of Estimated Fixed Demand Costs."

Table 5. Summary of Estimated Fixed Demand Costs
November 1, 2009 through October 31, 2010

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 6,642,704	Schedule 5A, Page 2 - Pipeline Allocated Cost
2.	Storage	$ 19,732,486	Schedule 5A, Page 2 - Storage Allocated Cost plus Page 3 - Annual Fixed Charges
3.	Peaking	$ 5,040,783	Schedule 5A, Page 2 – Peaking Allocated Cost plus Schedule 5A, Page 4 - Annual Fixed Charges
4.	Asset Management and Capacity Release Revenue	$ (4,335,643)	Schedule 5A, Page 5 - Total Projected Capacity Releases
5.	Total Demand Costs	$ 27,080,330	Sum Lines 1 through 4.

I present the detailed calculations of this demand cost forecast in Schedule 5A. On page 1 of the 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 2009 / 2010 gas year.

Q. Please provide the 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, pursuant to the Northern's

Delivery Service Terms and Conditions for the New Hampshire Division. This filing continues the capacity assignment demand revenue forecast for the New Hampshire Division, which was provided to the Commission for the 2009 / 2010 Winter COG filing. Northern estimated annual capacity assignment demand revenues for November 2009 through March 2010 of $1,657,812. I present the detailed calculations of this figure 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.

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 the second Attachment to Schedule 10B, and the supply sources available to Northern, which I presented in Schedule 12. I forecast supply prices at each supply cost, utilizing NYMEX natural gas contract price data and NYMEX 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 2010 Off-Peak Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Off-Peak Period in Table 6, below.

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes May 1, 2010 through October 31, 2010			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
LNG	$43,312	8,280	$5.2309
Empress	$1,137,791	185,801	$6.1237
Chicago	$6,151,941	996,278	$6.1749
Tennessee Production	$1,245,678	201,107	$6.1941
Niagara	$1,115,785	177,875	$6.2728
Tennessee Storage	$5,079	798	$6.3661
Total System	$9,699,585	1,570,139	$6.1775

In summary, projected delivered commodity costs equal approximately $9.7 million at an average delivered rate of approximately $6.18 per Dth. This information is also provided in Schedule 2. 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 rates found in Schedule 6B are found in the Attachment to Schedule 6B, which is titled, "Commodity Cost Rate Support."

Q. Please discuss the status of the PNGTS meter error in-kind payback.

A. In January 2008, Northern filed a letter with the Commission and the Office of the Consumer Advocate stating that an investigation of unaccounted-for gas in its New Hampshire Division had uncovered a metering problem on the Northern system. It was determined that Northern had been overcharged for 758,502 Dth due to this metering error. PNGTS began paying back this volume with in-kind gas on November 1, 2008. According to the agreement with PNGTS, Northern was to receive 1,382 Dth daily on a best-efforts basis at no cost until PNGTS has provided the full 758,502 Dth. Effective January 1, 2010, the pay-back of these volumes is complete.

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

A. I have also calculated the gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program. Based upon the January 25, 2010 NYMEX natural gas settlement price data, Northern projects a hedging gain of approximately $12,000. I have provided detailed calculations in Schedule 7. Actual results will be determined as financial positions are liquidated on the final day trading for each month.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2009 through October 2010.

A. Schedule 14 provides this information. The results are based upon the Sendout® analysis, which I provided to Mr. Simpson.

V. PROPOSED HEDGING PLAN FOR PERIOD BEGINNING MAY 2011

Q. Has Northern developed a plan for hedging the period of May 2011 through April 2012?

Yes. As agreed at the technical conference held on February 9, 2010 in Docket No. DG 09-141, Northern is providing its proposed hedging plan with this Cost of Gas consistent with its revised proposal filed in DG 09-141 on February 17, 2010. In that filing, Northern details the specific proposed changes to its hedging program, including permanent suspension of the price-based component of the program, introduction of a price ceiling and an appreciation rule, and changes to the determination of peak period volumes and the commencement of peak period purchasing six months earlier than under the current program.

The initial schedule for the hedging plan for the twelve-month period beginning May 2011 is presented 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 with the Cost of Gas update 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, the projections call for purchasing 126 futures contracts for the program years starting May 2011 and May 2012, and 128 contracts for the program year starting 2013.

Q. Do the proposed changes to the hedging program impact hedging plans for periods prior to May 2011?

A. Yes. Schedule 20, page 3 of 3 presents the current status of the hedge plans for the summer 2010 and winter 2010-11 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. The proposed changes do not impact the summer 2010 period since all transactions have been completed. As shown on Schedule 20, page 3 shows, the projected percentage of May and October supplies that are hedged is 74 percent, which greatly exceeds 40 percent. This higher level occurred because all of the price-based purchases were triggered. The proposed program changes do impact the winter 2010-11 period since the combination of physical supplies available at fixed prices and financial hedge transactions already exceeds 70 percent. As shown on Schedule 20, page 3, 76 percent of peak season requirements are expected to be available under a fixed price. Of this amount, five percent represents price-based transactions implemented on behalf of the New Hampshire Division. Had these transactions not been undertaken, Northern would still be positioned to enter the 2010-11 peak season with more than 70 percent of supplies available at a fixed price. Therefore, Northern proposes to suspend further financial hedging activity for the 2010-11 peak season.

VI. PNGTS Rate Case Litigation Update

Q. What is the current status of the litigation opposing the proposed rate increases by Portland Natural Gas Transmission System ("PNGTS") for which the Commission granted inclusion of costs incurred from December 1, 2008 through August 31, 2009 in the 2009-2010 Winter COG rates?

A. The Initial Decision of the Administrative Law Judge in FERC Docket No. RP08-306-000, the rate proceeding filed by PNGTS on April 1, 2008, was issued on December 24, 2009. Briefs on Exceptions to the Initial Decision were filed on February 22, 2010 and Briefs Opposing Exceptions are due April 5, 2010. Although no specific timeframe for an order from FERC is established, an order is expected approximately six months after the briefs are submitted, which would be during the October 2010 timeframe. PNGTS rates since September 2008 have been billed subject to refund at the rate proposed in April 2008. The FERC order would establish the rates applicable to the refund period as well as the prospective rates.

The PNGTS Shippers Group ("PSG") appeal to the U.S. Court of Appeals of the declaratory order in FERC Docket No. 09-1029, which reduces the capacity on PNGTS and thus threatens the "at-risk" condition, has been decided. Oral argument was heard on November 16, 2009 and the court's order was issued on January 26, 2010. The court dismissed the appeal on the grounds that it was uncertain whether PSG would incur an adverse rate impact as a result of the declaratory order because there was no immediate rate impact. However, the court did agree with PSG that the appropriate forum for determining a capacity reduction would be an abandonment proceeding and that potential economic impacts are appropriate for consideration as part of an abandonment proceeding. While

PSG did not prevail in overturning the declaratory order, the appeal was successful in preserving PSG's right to challenge it in a future proceeding. Had PSG not appealed the declaratory order, it would have been permanently bound by the order's capacity determination and unable to challenge it in the future. Activity in this docket is complete.

Q. What is the impact of the Initial Decision in FERC Docket No. RP08-306-000, should it be upheld by the FERC?

A. The Initial Decision was very favorable to Northern and the PSG, with PNGTS losing on most significant issues including treatment of bankruptcy revenues, capacity for purposes of the at-risk condition (affirmed at 210,840 Dth), return on equity, treatment of interruptible transportation revenues, negative salvage rate, depreciation rates, and type of cost levelization model. Should the final order from FERC uphold the Initial Decision, the rate impact is expected to be as follows. The daily firm transportation rate prior to the rate filing in April 2008 was $0.83 per Dth. The proposed rate of $0.90 per Dth became effective in September 2008, subject to refund with a refund floor of $0.85. PSG estimates that rates resulting from the Initial Decision would support a prospective rate of $0.76. Thus, unless the Initial Decision is substantially reversed, Northern expects a refund at the difference between the proposed rate and the refund floor rate for service provided from September 2008 until the new rates become effective. Northern estimates the refund to be approximately one million dollars ($1,000,000). Should the Initial Decision be upheld in its entirety, Northern estimates prospective charges to be approximately $700k less annually than before PNGTS filed the rate case.

Q. Does Northern intend to include expenses associated with on-going PNGTS rate case litigation costs incurred since September 2009 in its next Winter COG filing?

A. Yes. As I discussed in the introduction to my testimony, Northern intends to seek full recovery of PNGTS litigation expenses incurred since September 2009 through its 2010-2011 Winter COG rates in a manner similar to the expenses approved by the Commission in DG 09-167. The transportation services Northern receives from PNGTS are primarily winter-only; therefore Northern does not seek to recover litigation expenses with the current filing for Summer 2010 COG rates.

Q. Does Northern anticipate future litigation with PNGTS regarding firm transportation rates?

A. Yes. Although the rate case in RP08-306-000 is on track for resolving many issues with PNGTS, the declaratory order in FERC Docket No. 09-1029 is likely to result in PNGTS filing a subsequent rate case based largely on a reduced level of system capacity. Northern intends to segment any litigation activity associated with such a subsequent rate case, should one be filed, from the activity associated with RP08-306-000 and the appeal of the declaratory order so treatment of costs for such proceedings can be addressed on a discrete basis.

Q. Does this conclude your testimony?

A. Yes it does.