Prefiled Testimony of Francis X. Wells

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2009
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 area of energy supply acquisition, including natural gas supply procurement, electric default service purchasing, and regulatory testimony and reporting, budgeting for both natural gas and electric supply, and long-term supply planning.

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

A. Yes. I have testified before the Commission in docket 2008-155, the joint petition by Unitil and NiSource for the approval of the acquisition of Northern Utilities, Inc. ("Northern" or the "Company") by Unitil Corporation. I have also testified before the Commission on numerous occasions, relating to electric power supply costs of Northern's affiliate, Unitil Energy Systems, Inc.

Q. Please explain the purpose of your prepared direct testimony in this proceeding.

A. I describe and explain Northern's forecast of gas demand and the resulting forecasted gas sendout and estimated gas supply costs that I have developed for the New Hampshire and Maine Divisions. I provide a review of Northern's portfolio and a supply plan to cover the forecasted sendout requirements over the Summer period, as well as a plan for summer storage injection. I also describe the Company's hedging program and provide the Company's plan for applying Northern's approved hedging program to the 2010 Summer period.

James Simpson, Vice President of Concentric Energy Advisors, describes and explains the calculation of the Cost of Gas Adjustment ("COG Adjustment") that Northern proposes to bill from May 1, 2009 to October 31, 2009. He also discusses the 2008 Summer period reconciliation filing as well as the impact that the proposed COG Adjustment will have on the bills of the Company's typical customers.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution sales?

A. To forecast billed 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 demand for the large commercial customers with special contracts was developed separately for each of these customers.

Q. How does the Company forecast firm sendout?

A. First, the total firm distribution forecasted delivery quantities are allocated between sales and transportation services based upon Northern's recent history of actual deliveries to transportation customers as a percentage of total deliveries to sales and transportation customers. As I explain in this testimony, the estimated gas supply costs that I provided to Mr. Simpson for this filing are based on the gas supply costs to Northern's sales customers only.

Then I converted the sendout forecast from a billing month to a calendar month basis, based on the recent historical ratios of billing month deliveries to calendar month deliveries.

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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. Finally 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.

Q. Have you prepared a schedule to compare the forecasted sales for the 2009 Summer COG Adjustment period, May 2009 through October 2009 to actual weather-normalized normalized sales for the 2008 Summer COG Adjustment period?

A. Yes, I have prepared Attachment NUI-FXW-1 for that purpose.

III. ESTIMATED GAS SUPPLY COSTS

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

A. Northern has access to gas supply markets in the Gulf of Mexico, the northeastern and mid-continental United States, and both western and eastern Canada through its portfolio of natural gas transportation contracts. Transportation contracts with Tennessee Gas Pipeline, Texas Eastern Transmission, and Algonquin Gas Transmission, LLC ("Algonquin") provide access to the Gulf of Mexico and to the northeastern United States, while contracts with Vector Pipeline, the TransCanada Pipelines, Iroquois Gas Pipeline, Algonquin and the Portland Natural Gas Transmission System ("PNGTS") provide access to western Canada and the mid-continental United States.

Northern currently has storage contracts with Washington 10 Storage Corporation, Tennessee, and Texas Eastern. Northern has peaking supply contracts with FPL Energy Power Marketing, Inc ("FPL")[2] and Distrigas of Massachusetts Corporation ("Distrigas"). Under the FPL peaking contract, Northern has the right to call on a daily basis for natural

[2] Effective November 1, 2008, Northern consented to the assignment of the peaking supply contract with Duke Energy Trading & Marketing ("DETM") to FPL.

gas, delivered to Granite State Gas Transmission ("Granite"). Under the Distrigas peaking contract, Northern has the right to call on a daily basis for either Liquefied Natural Gas ("LNG"), which can be trucked to its LNG facility in Lewiston, Maine or on natural gas delivered to Granite.

With the exception of its peaking contracts, Northern's current practice is to secure its gas supply commodity contracts through seasonal requests-for-proposal ("RFP"). Northern is currently preparing an RFP to procure the actual supplies necessary to meet its projected summer requirements, including projected summer sales customer demands and storage injections.

All pipeline supplies are delivered through the Company's affiliate pipeline, Granite, with the exception of deliveries to Northern's city gate with the Maritimes & Northeast Pipeline, located in Lewiston.

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Simpson to calculate the 2009 Summer COG Adjustment.

A. I prepared an updated commodity cost estimate, based upon Northern's portfolio of pipeline, storage, and peaking supply contracts, as discussed above. Pipeline, storage, and peaking contract demand charge estimates, which were previously approved by the Commission in the Company's 2008-09 Peak COG Adjustment proceeding, have been continued for the Company's 2009 Summer COG Adjustment filing. I have prepared an updated commodity cost forecast, based on current commodity prices, variable transportation and fuel retention rates, base load gas commitments and LNG boil-off, utilizing the Sendout® natural gas supply cost optimization model to provide an optimal cost result, based on the economic and operational parameters entered by the Company. I have also calculated the gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program.

I prepared Attachment NUI-FXW-2 to summarize the annual estimated demand costs, as previously approved by the Commission in the 2008-09 Peak COG Adjustment proceeding.

I also prepared Attachment NUI-FXW-3 to show the monthly forecasted commodity cost detail, by supply option. Page 1 of Attachment NUI-FXW-3 provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 1 also provides the calculation of the hedging gains or losses. Page 2 of the Schedule provides delivered volumes (Dth) by supply source. Finally, Page 3 provides delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

The table below, titled, "Summary of Estimated Gas Supply Costs," provides a summary of annual Northern demand and commodity gas supply estimates for the period May 2009 through April 2010. Mr. Simpson explains in his testimony how these costs are allocated to the New Hampshire and Maine Divisions; to Peak and Off Peak periods; and to rate classes.

Northern Utilities, Inc. Summary of Estimated Gas Supply Costs May 2009 through April 2010			
Line	Description	Amount	Reference
1	Pipeline Demand	$10,471,699	Attachment NUI- FXW-2, Page 1
2	Storage Demand	$16,879,742	Attachment NUI- FXW-2, Page 1
3	Peaking Demand	$4,204,350	Attachment NUI- FXW-2, Page 1
4	Subtotal Demand	$31,555,791	Sum Lines 1 through 4.
5	Capacity Release	($960,000)	Page 31 of Revised Winter COG Adjustment Filing, 10/17/2008
6	Asset Management	($2,400,000)	Page 31 of Revised Winter COG Adjustment Filing, 10/17/2008
7	Net Demand Costs	$28,195,791	Sum Lines 4 through 6.
8	Summer Commodity Costs	$7,565,333	Attachment NUI- FXW-3, Page 1, May - Oct, Total Variable Supply Costs
9	Summer Hedging (Gain)/Loss	$2,314,710	Attachment NUI- FXW-3, Page 1, May - Oct, Futures (Profit) or Loss
10	Peak Commodity Costs	$32,757,686	Attachment NUI- FXW-3, Page 1, Nov - Apr, Total Variable Supply Costs
11	Peak Hedging (Gain)/Loss	$2,663,280	Attachment NUI- FXW-3, Page 1, Nov - Apr, Futures (Profit) or Loss
12	Subtotal Commodity Costs	$45,301,009	Sum of Line 6 through Line 8.
13	Total Gas Supply Costs	$73,496,800	Sum of Line 10 and Line 15.

Q. Has the Company accounted for retail migration[3] in its gas supply budget?

A. Yes, it has. I have reduced Northern's projected sendout requirement by the projected sendout requirement that is expected to be served by retail suppliers. The commodity costs included in the cost summary table exclude costs to serve customers electing transportation-only service from the Company.

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3 Retail migration refers to customers switching from bundled sales service to unbundled distribution service, with a competitive retail supplier providing the gas supplies.

While the demand charges presented in the cost summary table include total company demand costs, I have also estimated that the Company will receive approximately $1.1 million as revenue offset to the demand costs through the New Hampshire Division capacity assignment program to retail suppliers. The detailed calculations to support the projected capacity assignment revenues are provided on page 2 of Attachment NUI-FXW-2. As discussed by Mr. Simpson, this amount is deducted from the annual demand charges allocated to the Maine Division to be recovered through the proposed 2009 Summer COG Adjustment.

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 Public 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 committed to pay back this volume with in-kind gas, beginning November 1, 2008. According to the agreement with PNGTS, Northern will receive 1,382 Dth daily on a best-efforts basis at no cost[4] until PNGTS has provided the full 758,502 Dth. The pay-back may be at a higher daily amount with mutual agreement by the PNGTS and Northern. For the purpose of estimating the cost of gas for the Summer period, I assumed that PNGTS would deliver the 1,382 each day.

[4] Transportation costs on Granite of $0.0017 per Dth will be charged and fuel losses of 0.5% on Granite have been applied.

Q. Please provide the documentation for the gas supply rate inputs used to generate the gas supply cost estimates.

A. I have prepared Attachment NUI-FXW-3, which provides the NYMEX prices and tariff sheets used to generate the gas supply estimates for the COG Adjustment. The NYMEX prices reflect the NYMEX settlement on January 29, 2009. The Company intends to revise its commodity cost estimates to reflect NYMEX prices closer to the effective date of the proposed COG Adjustment. Attachment NUI-FXW-3 also includes the negotiated transportation rates and transportation tariff sheets, which were provided for the 2008-09 Peak COG Adjustment filing. These pages document the calculations provided in Attachment NUI-FXW-4.

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

A. I have prepared Attachment NUI-FXW-5 to provide this information. The results are based on the Company's Sendout® analysis. Page 4 of Attachment NUI-FXW-5 is Northern's first semi-annual report of in-kind volumes received from PNGTS as required by Commission Order 24,912, issued October 31, 2008 in Docket DG 08-115.

IV. HEDGING

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

A. Northern currently holds thirty-one May 2009 natural gas futures contracts and thirty-nine October 2009 natural gas futures contracts. The average purchase prices are $8.101 per Dth for the May 2009 contracts and $8.48 per Dth for the October 2009 contracts. As of January 29, 2009, the estimated exit price was $4.724 per Dth for the May 2009 contracts and $5.229 per Dth for the October 2009 contracts. The resulting loss on these futures contracts is $1,046,890 for the May 2009 contracts and $1,267,820 for the October 2009 contracts. I present these calculations on page 1 of Attachment NUI-FXW-1.

Q. What are the Company's plans for hedging the 2009 Summer period and the 2009-2010 Peak period?

A. Based on the analysis that I prepared of Northern's projected pipeline requirements for the 2009 Summer period and the 2009-2010 Peak period, the Company does not need to purchase additional futures contracts at this time. This analysis can be found on page 2 of Attachment NUI-FXW-6. The NYMEX contracts in Northern's portfolio are adequate to meet the expected pipeline requirements the hedging program was intended to cover.[5]

Attachment NUI-FXW-6, page 2, line 7 shows projected sendout, which accounts for retail migration. Lines 11 through 32 on that same page show my calculations of potential non-pipeline supplies, based on total inventory or annual contract maximums. These non-pipeline supplies include Washington 10 storage, Tennessee storage, and the Distrigas peaking contract. Total resource deliverable volumes from each of these supply sources are reduced to account for upstream pipeline fuel losses and the retail supplier capacity assignment programs for both the New Hampshire and Maine Divisions.

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5 The program is intended to cover 40% of Northern's projected pipeline requirements with time-triggered hedges and up to an additional 30% with price-triggered hedges. Since the filing of the Peak 2008-09 COG Adjustment, all three price targets for both seasons have been met.

Line 36 shows the calculation of the Pipeline Requirement for the season, which is the difference between Total Non-Pipeline Supplies and the Firm Sendout Requirement. I converted the Pipeline Requirement into numbers of futures contracts for both the time-triggered and price-triggered portions of the hedging plan, shown on Lines 37 and 38. Finally, I compared the number of contracts currently owned by Northern for each season, shown on line 40, with the number of Planned Contracts, shown on line 39. This analysis shows that Northern's current NYMEX contract holdings exceed the Planned Contracts for both the 2009 Summer and 2009-2010 Peak periods. Based on this analysis, Northern will not enter into additional hedges covering these seasons.

Q. Has Northern developed a plan for hedging the 2010 Summer period in accordance with the hedging program?

A. Yes. The hedging program requires the Company to purchase NYMEX natural gas futures contracts for May and October of each Summer period. I developed a sendout forecast for May 2010 and October 2010 using the methodology described earlier for forecasting gas sendout. The hedging program requires Northern to purchase 40% of projected pipeline requirements on a time-triggered basis and up to an additional 30% on a price-triggered basis for three separate price-trigger points which are updated with each COG Adjustment filing.

Please refer to Page 3 of Attachment NUI-FXW-6 for the calculations used to determine the hedging volumes for the 2010 Summer hedging plan. Total Time-triggered contracts, presented on page 3 of Attachment NUI-FXW-6, will be evenly distributed over the 12 month period beginning March 2009. Price-triggered contracts will be purchased at three separate pricing targets, as discussed below.

Q. Please provide the prices to be used for the price-triggered portion of the hedging plan.

A. Pursuant to Commission Order dated January 7, 2003 in Docket No. 2001-679, the prices for the price-triggered component of the hedging program are reestablished every six months, at the time of the seasonal COG Adjustment filings. These prices are based on trigger points set at the 65^{th}, 35^{th} and 20^{th} percentiles of a matrix of NYMEX traded futures contracts analyzed by Risk Management Inc. ("RMI"), an independent consultant retained by the Company. The RMI price matrix is adjusted for inflation and weighted, with 20% of the price being attributed to the most recent year (short-term) and 80% being attributed to the last four years (long-term). The current update establishes the following price triggers: the 65^{th} percentile price is $7.85 per Dth, the 35^{th} percentile is $6.90 per Dth and the 20^{th} percentile is $6.38 per Dth. Please refer to page 4 of Attachment NUI-FXW-6 for a copy of the RMI calculations and page 5 of the Attachment for a copy of my calculation of the price triggers. The subsequent pages of Attachment NUI-FXW-6 provide a copy of the most recently filed monthly hedging report.

Q. Are there unusual circumstances regarding the price-triggered aspect of the 2010 Summer period hedging plan?

A. Yes, based on the recent decline in NYMEX pricing, current prices are well below the 20^{th} percentile price target and Northern has executed price-triggered hedges for all three tiers in accordance with 2010 Summer period hedging plan..

Q. Does the Company plan to review, assess, and recommend modifications as appropriate to the hedging program?

A. Yes, Northern intends to file a comprehensive review and assessment of the hedging program on April 15, 2009.

Q. Does this conclude your testimony?

A. Yes it does.