Prefiled Testimony of James D. Simpson

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2009
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
JAMES D. SIMPSON

I. INTRODUCTION

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

A. My name is James D. Simpson. I am a Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Marlborough, Massachusetts 01752.

Q. Please describe your relevant work experience.

A. I have over 30 years experience in the energy industry in a variety of roles and responsibilities with an overall focus on economics, pricing, forecasting and regulatory matters. I was employed by Bay State Gas Company ("Bay State") from 1982 until 2000; for much of my time at Bay State, I was responsible for rates and regulatory affairs for Bay State and Northern Utilities, Inc. ("Northern"). I have been with Concentric Energy Advisors ("Concentric") since 2005. My professional qualifications and experience are provided in Attachment NUI-JDS-1 of this testimony.

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

A. Yes, while I was employed by Bay State, I testified before the Commission on behalf of Northern in many proceedings on a variety of issues related to rates and other economic and regulatory matters.

Q. For what purpose has Northern retained Concentric?

A. Unitil Service Corp. ("Unitil") requested Concentric's assistance with several tasks related to Cost of Gas Factors ("COG") for the New Hampshire and Maine divisions of Northern. As part of the overall effort to integrate Northern's business and operating functions into Unitil after the acquisition of Northern from NiSource Inc. ("NiSource") on December 1, 2008, Unitil requested that Concentric: (1) review the Excel files that NiSource had provided to Unitil, which NiSource had developed to calculate Winter Period and Off-peak Cost of Gas ("COG") Adjustments for the New Hampshire and Maine divisions; (2) if necessary, revise the Excel files to make the COG calculation process more efficient, transparent, and reviewable; (3) testify on behalf of Northern in the 2009 Summer Period COG proceedings and (4) provide training to Unitil personnel concerning the COG calculation process and the Excel COG file that Concentric developed.

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

A. Francis X. Wells, Senior Energy Trader for Unitil and I are sharing the responsibility for describing and explaining the proposed 2009 Summer Period New Hampshire Division COG in this proceeding. Mr. Wells will describe and explain the forecast of gas demand and the resulting forecasted gas sendout and gas costs that he developed for the New Hampshire and Maine divisions. Mr. Wells will also describe the Company's Hedging Program.

I will describe and explain the calculation of the COG Adjustment that the New Hampshire Division proposes to bill from May 1, 2009 to October 31, 2009. I will also discuss the prior Off-peak period reconciliation filing as well as the impact that the proposed COG Adjustment will have on the bills of the Company's typical customers.

Q. Please provide a list of the attachments that you have prepared in support of your testimony.

A. The attachments that I have prepared in support of my testimony are listed below.

Attachment NUI-JDS-1	James D. Simpson Professional Qualifications
Attachment NUI-JDS-2	Allocation of Northern Fixed Capacity Costs
Attachment NUI-JDS-3	New Hampshire SMBA Allocations
Attachment NUI-JDS-4	New Hampshire Division Sales and Sendout Forecast
Attachment NUI-JDS-5	Allocation of Fixed and Variable Gas Costs to New Hampshire Firm Sales Rate Classes
Attachment NUI-JDS-6	Allocation of Commodity Costs to New Hampshire and Maine Divisions
Attachment NUI-JDS-7	Total Sales Sendout Quantities and Commodity Costs, New Hampshire Division
Attachment NUI-JDS-8	New Hampshire 2008 Summer Reconciliation Filing
Attachment NUI-JDS-9	New Hampshire Division 2009 Summer Tariff Sheets
Attachment NUI-JDS-10	Supporting Detail to the Tariff Sheets
Attachment NUI-JDS-11	New Hampshire Division Gas Cost Variance Analysis, Proposed Summer 2009 vs. Actual Summer 2008
Attachment NUI-JDS-12	New Hampshire Division 2009 Summer Typical Bill, Bill Impact Analyses

II. COST OF GAS RATE

A. Preliminary Matter

Q. You explained in your introductory comments that you were requested to review the COG files that NiSource had provided to Unitil and to make any revisions that were necessary to make the COG calculation process more efficient and reviewable. Please summarize the results of your review.

A. Although NiSource's COG model provided appropriate COG calculations that comply with Northern's currently effective Cost of Gas Clause[1], Concentric found that it was difficult to perform "quality control" measures on the COG calculations because of the way that the NiSource COG model was organized. We also determined that it was difficult to maintain control of revisions to the COG filings that are made during the course of COG proceedings in New Hampshire and Maine. To address these concerns, Concentric developed a single COG file in place of NiSource's separate, linked files. Concentric also re-organized the COG file in the following ways:

- A series of input spreadsheets was created so that all data from outside the COG model can be entered in an orderly manner into these dedicated spreadsheets.[2]
- Worksheet tabs were renamed and re-ordered by major function.
- Calculations in the COG file were reorganized to generally flow from worksheets located left to right and within worksheets from rows located top, down.

Q. Please describe and explain any changes that Concentric made to the COG calculations.

A. In addition to the spreadsheet design changes that I listed in the prior response, Concentric made the following minor changes to the calculation of the COG, to improve the accuracy of the calculations:

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1 As provided for in Second Revised Page 18 through First Revised Page 37.1.

2 The dedicated data input spreadsheets enhance the process of checking for data entry errors and ensuring that all data updates have been made.

- Formulas and spreadsheet layout were modified so that the COG calculations are based on data specific to firm sales, excluding assigned capacity for firm transportation customers; this change is explained in the following response.
- Sales service demand costs are calculated by subtracting estimated capacity assignment revenues associated with New Hampshire non-grandfathered transportation customers from total New Hampshire allocated demand costs.
- The calculation of the COG Adjustment was modified so that total Northern hedging gains and losses are forecasted for each month in the forecast period and allocated to New Hampshire and Maine divisions within the COG file in the same manner that monthly commodity costs are allocated to the divisions.
- The determination of the New Hampshire forecast sendout measured in Dth was modified so that the calculations are performed within the COG model by grossing up forecasted firm sales, measured in Dth, by assumed percentages for Company Use and Lost-and-Unaccounted-For gas.

Q. The first modification that you listed is that the COG calculations are now based on data specific to firm sales, excluding assigned capacity for firm transportation customers. Please explain this change.

A. Concentric made this modification as a result of the initial review and assessment of the COG process and Excel spreadsheets that Unitil and Concentric performed. During this initial review, Unitil determined that calculating the COG using sales-specific data (e.g. forecast delivery volumes, forecast commodity costs and forecast demand costs for firm sales classes), rather than combined sales and assigned transportation data[3] would improve the COG process and the accuracy of the COG estimate. Specifically, Unitil made this change so that the COG forecasts can be used in Unitil's internal financial planning and so that Unitil can more readily perform variance analyses at the conclusion of each COG period to determine the reasons for differences between forecast and actual results.

B. Allocation of Demand-Related Costs

Q. Please explain the basis for allocating the projected fixed, capacity-related costs, i.e., pipeline reservation and gas supply demand charges between Northern's New Hampshire and Maine divisions.

A. These costs are allocated between the divisions based on the Modified Proportional Responsibility ("MPR") methodology, which allocates the fixed capacity-related gas costs based on the demand each division places on the available capacity each month. The MPR methodology was approved by the Commission on December 23, 2005, effective January 1, 2006, pursuant to the Commission-approved Settlement in DG-05-080[4]. Accordingly, the MPR method was used to establish the proportional cost responsibility of Northern's New Hampshire and Maine Divisions in the 2008-2009 Winter Period COG filing. This 2009 Summer Period COG filing uses the 2008-2009 Winter Period factors to allocate Northern demand-related costs between the two divisions. The analysis that supports the MPR factors from the 2008-2009 Winter Period COG filing is provided in Attachment NUI-JDS-2.

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3 Northern's COG Clause allows for the calculation of the peak period COG to be based on (1) sales data or (2) sales plus assigned capacity (i.e., volumes and costs associated with non-grandfathered transportation customers) data.

4 The Maine PUC also approved the MPR methodology to be effective January 1, 2006 in Docket Nos. 2005-077 and 2005-273.

Q. Please explain how the projected demand-related costs that were allocated to New Hampshire are then allocated to months.

A. The share of Northern's costs that was allocated to the New Hampshire division was assigned to the Summer and Winter seasons based on the Simplified Market Based Allocation Method ("SMBA"), which was approved by the Commission in the 2007 Summer COG proceeding, DG-07-033. Detailed support for the allocation of New Hampshire demand costs to months is provided in Attachment NUI-JDS-3.

There are several components to New Hampshire Division demand-related costs: (1) Pipeline and product; (2) storage and peaking; (3) capacity release revenues[5]; (4) asset management fees[5]; (5) Interruptible margins[5]; (6) Firm Sales Service Re-Entry Fee revenues[5]; (7) Local production; and (8) Other A&G.

The (1) pipeline and product and (2) storage and peaking demand costs associated with New Hampshire sales customers (Attachment NUI-JDS-3, Page 1, lines 21 – 25) were calculated by subtracting the costs of capacity that were assigned to New Hampshire Non-Grandfathered transportation customers (Attachment NUI-JDS-3, Page 1, lines 8 – 18) from the total demand costs (Attachment NUI-JDS-3, Page 1, lines 1 – 5). Pipeline and product demand costs to sales customers (Attachment NUI-JDS-3, Page 1, line 22 and 29) were separated into demand costs related to (1) base use (Attachment NUI-JDS-3, Page 1, line 30) and (2) remaining use (Attachment NUI-JDS-3, Page 1, line 31); one twelfth of the annual base use pipeline and product demand costs to sales customers was then allocated to each

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5 These revenues, fees, and margins are credits to the allocated New Hampshire demand costs.

month (Attachment NUI-JDS-3, Page 2, line 3) and the remaining use demand costs for sales customers were allocated to months according to a New Hampshire Division sales customer Remaining Load PR allocator (Attachment NUI-JDS-3, Page 1, lines 37 - 57). Storage and Peaking demand-related costs to sales customers were also allocated to months according to the New Hampshire Division sales customer Remaining Load Peak PR allocator. New Hampshire's share of projected capacity release revenues; asset management fees; New Hampshire interruptible sales margins and local production and storage costs were allocated to the six Winter Period months (Attachment NUI-JDS-3, Page 2, lines 10 – 12) based on a Winter Period Remaining Load PR allocator. Northern does not forecast any Firm Sales Service Re-Entry Fee revenues in this period. Finally, Miscellaneous Overhead expense was assigned to the Summer and Winter Periods in proportion to sales and non-grandfathered transportation volumes by season.

Q. For this 2009 Summer Period COG filing, how were the New Hampshire Division sales service demand-related costs that were allocated to each off-peak month then allocated to each sales rate class?

A. The New Hampshire Division sales service demand-related base costs for a month were allocated to each sales service rate class based on that class' prorata share of total forecasted firm sales sendout in that month. The demand-related remaining costs for a month were allocated to each sales service rate class based on that class' prorata share of total forecasted firm sales design day temperature sensitive demand. The Sales forecast and the total, base and remaining sendout forecasts are provided in Attachment NUI-JDS-4; the detail of the forecasted monthly demand costs by class is provided in the following pages of Attachment NUI-JDS-5:

Demand Cost Component	Attachment NUI-JDS-5
Base Demand	Page 1, lines 1 through 17
Remaining pipeline demand	Page 2, lines 36 through 53
Peaking and storage demand	Page 3, lines 1 through 18
Remaining capacity release and asset management	Page 3, lines 22 through 39
Remaining Interruptible margins	Page 3, lines 43 through 60
Remaining Re-entry Fee Credits	Page 4, lines 1 through 18

C. Allocation of Variable Costs

Q. What is the basis for allocating the variable gas costs between Northern's New Hampshire and Maine divisions?

A. Mr. Wells provided to me a forecast of Northern variable gas costs by month. These variable gas costs have been allocated between the New Hampshire and Maine divisions on the basis of each division's percentage of monthly firm normal sendout. The analysis that supports the allocation of the 2009 Summer Period variable gas costs between New Hampshire and Maine is provided in Attachment NUI-JDS-6.

Q. For this 2009 Summer Period COG filing, how were the New Hampshire Division sales service variable gas costs that were allocated to each Summer Period month then allocated to each sales rate class?

A. The New Hampshire Division sales service variable gas costs for a month were allocated to each sales service rate class based on that class' prorata share of total forecasted firm sales sendout in that month. Maine total sales sendout and allocated commodity costs are provided in Attachment NUI-JDS-7. The detail of the forecasted monthly variable costs allocated by class is provided in the following pages of Attachment NUI-JDS-5:

Variable Cost Component	Attachment NUI-JDS-5
Base commodity	Page 1, lines 21 through 37 and page 5, lines 1 through 14
Remaining commodity	Page 2, lines 18 through 32 and page 5 lines 17 through 30
Total commodity	Page 5, lines 33 through 46

D. Refunds

Q. Are there any refunds included in this filing?

A. No, there are no refunds included in this filing.

E. Prior Summer Period Reconciliation

Q. Please explain the 2008 Summer Period under-collection of $494,006.

A. The reconciliation analysis that was filed with the Commission on January 23, 2009, and included as Attachment NUI-JDS-8, provides the explanation and support for the $494,006 under-collection.

F. Miscellaneous Charges and Credits

Q. Have you credited any revenues to gas costs in the Summer Period reconciliation and reflected any revenues as credits in the projected 2009 Summer Period gas costs in the COG calculation associated with revenues received from the Firm Sales Service Re-Entry Fee assessed to transportation customers returning to sales service?

A. No. Northern is not projecting any Firm Sales Service Re-Entry Fee revenues in this period. In addition, Northern considers the capacity that it has on hand to enable it to accept transportation customers return to sales service is related to capacity secured for and needed to meet winter demand, and therefore the credits for assessing this fee are most appropriately credited to the winter period cost of gas, and will be reflected in the Winter period COG proceeding.

G. Cost of Gas Adjustments

Q. Please explain how you calculated the Cost of Gas Adjustment rates for the 2009 New Hampshire Division Summer period.

A. Attachment NUI-JDS-9 includes the tariff pages that Northern is filing to be effective May 1, 2009. Forty-second Revised Page No. 38 presents the calculation of the 2009 Summer Period total anticipated (direct) Cost of Gas. Forty-second Revised Page No. 39 presents (1) the calculations of indirect gas costs, including Working Capital and Bad Debt allowances, the 2008 Summer Period undercollection balance; (2) a summary of total anticipated direct, indirect and total Costs of Gas; and (3) Forecasted CGAs for Residential, C&I Low Winter Use, and High Winter Use customer classes. Finally, Thirty-seventh Revised Page 94 and Thirty-seventh Revised Page 95 show the total Summer 2009 billed rates and total Summer 2009 delivery rates for all firm sales service rate classes and Thirty-seventh Revised Page 96 shows the total Summer 2009 delivery rates for all firm transportation service rate classes and for interruptible transportation service.

Q. Please explain the calculations that you made to determine each of the indirect gas costs.

The prior period undercollection of $502,551 that is shown in Attachment NUI-JDS-9, page 2, line 30 is the undercollection balance as supported in Attachment NUI-JDS-8 with additional interest expense through April 2009. The calculation of interest on the undercollection balance is provided in Attachment NUI-JDS-10, page 6.

The Working Capital Allowance that is shown in Attachment NUI-JDS-9, page 2, line 27 is supported by calculations on lines 1 through 12 of that page; the Working Capital Allowance percentage that was established by the Commission is shown on Second Revised Page 21. The Bad Debt Allowance that is shown in Attachment NUI-JDS-9, page 2, line 28 is supported by calculations on lines 15 through 24 of the same page; the Bad Debt percentage was also established by the Commission and is shown on Second Revised Page 21.

The Miscellaneous Overhead that is shown in Attachment NUI-JDS-9, page 2, line 29 is the Summer period allocation of the Commission-approved Miscellaneous Overhead, as shown on Second Revised Page 21 of the Company's Cost of Gas Clause. The allocation of the total Commission-approved Miscellaneous Overhead to the Summer period is shown on Attachment NUI-JDS-3, page 2, line 17.

Q. Please explain the calculations that you made to determine the Forecasted COGs for Residential, C&I Low Winter Use, and High Winter Use customer groups as shown on Attachment NUI-JDS-9 page 2 (Forty-second Revised Page 39), lines 43 – 52.

Q. I have prepared Attachment NUI-JDS-10 to provide additional detail on the calculation of class-specific 2009 Summer COG rates. Attachment NUI-JDS-10 page 1 shows summary calculations of the demand, commodity, and indirect cost components for the three customer groups.

Page 2 of the same attachment shows the calculation of the Residential 2009 Summer COG at the overall New Hampshire division average COG, and the reassignment of the difference between (1) Residential gas costs at the New Hampshire average COG and (2) gas costs allocated to the Residential group according to SMBA allocators, to the C&I HLF and LLF customer groups.

Attachment NUI-JDS-10, pages 3 through 5, show the detailed gas cost data that Mr. Wells provided to me.

Attachment NUI-JDS-10 page 6 shows the projected monthly deferred gas cost balances through October 2009, i.e. the end of the 2009 Summer COG period.

III. SUMMARY ANALYSES

Q. How does the proposed 2009 Off-peak period COG rate compare with the 2008 Off-peak period COG rate?

A. Attachment NUI-JDS-11 provides an analysis of the projected gas costs for the 2009 Summer COG compared to the actual 2008 Summer gas costs. Attachment NUI-JDS-11 shows that the projected 2009 Summer cost of gas, $.8020 per therm, is $.3386 per therm lower than the actual 2008 cost of gas per therm. This decrease in the cost of gas is primarily the result of significantly lower commodity costs; 2009 commodity gas costs are projected to be lower by $.3918 per therm.

Attachment NUI-JDS-12 pages 1 and 2 show that the total 2009 Summer cost of gas service to the typical residential heating customer with gas demand of 153 ccf will be $246.27, which is $51.41 or 17.27% less than the 2008 Summer cost of gas service to this typical residential heating customer.

Finally, Attachment NUI-JDS-12 page 3 shows the Residential Heating bill impact analysis comparison of Summer 2009 to Summer 2008 rates for a range of monthly bills.

IV. FINAL MATTERS

Q. Will the Company propose to revise the COG if it receives any new or updated information on supplier or transportation rates?

A. Yes. If the Company receives new or updated information on Northern's forecast supplier/transportation rates, Northern will notify all parties to this proceeding and will propose to revise the COG if the change is material and if all parties will have sufficient time to review the proposed change before the effective date of May 1, 2009.

Q. Does this conclude your testimony?

A. Yes it does.