Northern Utilities, Inc.

New Hampshire Division

WINTER SEASON 2010-2011
PROPOSED COST OF GAS ADJUSTMENT

TO BE EFFECTIVE NOVEMBER 1, 2010

FILED SEPTEMBER 15, 2010

Unitil
Northern Utilities, Inc.

Prefiled Testimony of James D. Simpson

Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2010 / 2011
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" or "Northern Utilities"). 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, I testified on behalf of Northern Utilities in the 2009 / 2010 Winter Cost of Gas ("COG") proceeding, Docket No. DG 09-167, the 2009 Summer Cost of Gas proceeding, Docket No. DG 09-052, and the 2010 Summer Cost of Gas proceeding, Docket No. DG 10-050. In addition, while I was employed by Bay State, I testified before the Commission on behalf of Northern Utilities in many proceedings on a variety of issues related to rates, growth-related projects and other economic and regulatory matters.

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

A. Francis X. Wells, Senior Energy Trader for Unitil; Joseph F. Conneely, Senior Regulatory Analyst for Unitil; and I are sharing the responsibility in this proceeding for describing and explaining the proposed 2010 / 2011 Winter New Hampshire Division COG rate adjustment that the Company is proposing to make effective November 1, 2010. 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 Maine and New Hampshire divisions. Mr. Wells will also describe the impact of the Company's Hedging Program for the 2010 / 2011 Winter period. Mr. Conneely will discuss the calculation of the 2010 / 2011 Environmental Response Cost Rate Adjustment, and typical bill analyses for the proposed Winter New Hampshire Division COG rates.

I will describe and explain the calculation of the COG that Northern Utilities proposes to bill from November 1, 2010 to April 30, 2011. I will also discuss the New Hampshire 2009 / 2010 Winter Cost-of-Gas Reconciliation Filing.

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-1	James D. Simpson Professional Qualifications
Summary Schedule	Supporting Detail to the Tariff Sheets Bad Debt, Working Capital
Schedule 1A	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons

Schedule 1B	New Hampshire Division Commodity Cost Analysis
Schedule 3	New Hampshire Division (Over) / Undercollection Balances and Interest Calculations
Schedule 9	Variance Analysis / Comparison to 2009 Off-Peak
Schedule 10A	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Schedule 10B	Division Sales and Sendout Forecast
Schedule 10C	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 14	Northern Utilities Inventory Activity
Schedule 22	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 21	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 23	Supporting Detail to Proposed Tariff Sheets

II. COST OF GAS FACTOR

A. Allocation of Demand-Related Costs to Maine and New Hampshire Divisions

Q. Please explain how the projected fixed capacity-related costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs and (c) peaking resource capacity costs are allocated between Northern's Maine and New Hampshire divisions.

A. Total Northern capacity-related costs are allocated between the Maine and New Hampshire divisions by application of the Modified Proportional Responsibility ("MPR") methodology. The MPR methodology allocates fixed capacity-related gas costs to the Maine and New Hampshire divisions in a two-step process: (1) capacity-related costs, by resource type[1], are allocated to months by application of MPR allocation factors, and (2) the capacity related costs allocated to each month are allocated to the Maine and New Hampshire divisions

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1 Pipeline, storage, and peaking

based on the relative shares of Design Year demand[2] in that month. This MPR methodology was orally approved by the Commission on December 30, 2005 to be effective January 1, 2006. Subsequently, on June 1, 2006, the Commission issued Order No. 24, 627 in docket DG 05-080 granting written approval of the MPR methodology.

As I will explain in more detail in the following responses, I used the MPR methodology to allocate total Northern annual demand costs to the Maine and New Hampshire divisions for the 2010 / 2011 Winter period, i.e. November 2010 through April 2011, and for the 2011 Summer COG, i.e. May through October 2011.

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2010 through October 2011 to the Maine and New Hampshire divisions.

A. I have prepared Schedule 21 to explain how I calculated the MPR factors and then how I used these factors to allocate total Northern annual demand costs for the period November 2010 through October 2011 ("COG Period") to the Maine and New Hampshire divisions. Schedule 21 is arranged in three major sections: (1) Total fixed capacity costs, by type of resource (pipeline, storage, and peaking) are summarized in Lines 1 through 10. (2) These fixed capacity costs for each resource type are allocated to each month in the COG Period according to MPR allocators that were developed specifically for each resource type as shown on Lines 13 through 56 (Schedule 21, pages 1 and 3); the MPR allocators are based

2 For the MPR allocation process, Design Year demand is calculated as the actual demand to Maine and New Hampshire firm sales and assigned capacity / non-grandfathered transportation customers for the period May, 2009 through April 2010, adjusted to reflect design conditions from November through October.

on design year sendout volumes for each resource type. (3) The fixed capacity costs that are allocated to each month in Step 2 are then allocated to the Maine and New Hampshire divisions according to design year total firm sendout as shown in Lines 58 through 90. The last column of Pages 2 and 4 of Schedule 21 are descriptions of the sources of data and explanations of the calculations that I have included in Schedule 21 and other attachments to my testimony.

Q. Please explain how you allocated total Northern Fixed Capacity Costs to the months in the COG Period.

A. Lines 3 through 6 of Schedule 21 show the total Northern annual projected demand costs for Pipeline, Storage, and Peaking resources; these forecasted demand costs were provided to me by Mr. Wells.[3] Mr. Wells also provided estimates of Capacity Release revenues and Asset Management revenues, which I have summarized in Lines 8 and 9 of Schedule 21. As shown on Schedule 21, Line 7, Northern Utilities' share of litigation costs that have been incurred by the PNGTS Shippers Group ("PSG") in the PNGTS rate case, RP08-306 from September, 2009 to mid-August 2010 is $326,567. For the purpose of incorporating the PNGTS Litigation Expense, which is discussed in Mr. Well's testimony, into the cost of gas rates, I have reflected these costs as an offset to Asset Management revenues throughout the attachments to my testimony. Mr. Wells has also provided an estimate refunds from the PNGTS rate cast RP08-306. I have added the sales customers' portion of the PNGTS refund to the Asset Management revenues, net of the PNGTS litigation costs.

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[3] The forecast of demand costs that Mr. Wells prepared is provided in Schedule 5.

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and Peaking demand costs to each month are shown on Schedule 21, Lines 17 through 22, Lines 33 through 40 and Lines 44 though 49, respectively. In addition, Lines 26 through 29 show the calculation of the Injection Fees by month. Injection Fees are the capacity costs of that portion of Northern's pipeline capacity that is used to transport gas to the underground storage fields; these Injection Fees are added to the Storage demand costs, as shown on Line 39, and subtracted from the Pipeline demand costs, as shown on Line 53.

Northern fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 50 through 56. Lines 50, 51 and 52 repeat the Pipeline, Storage, and Peaking capacity costs from Lines 22, 40, and 49. Line 53 shows the credit to Pipeline capacity costs that is related to the Injection Fees that have been added to the Storage capacity costs. In addition, (a) $1/5^{th}$ of total Capacity Release revenues are allocated to each month from November through March, as shown on Line 54 and (b) $1/6^{th}$ of total Asset Management revenues, net of Northern's share of PSG costs are allocated to each month from November through April, as shown on Line 55.

Q. Finally, how are the total Demand Costs and the Capacity Release and Asset Management revenues net of Northern's share of PSG costs, which have been allocated to each month according to the process that you described above, allocated to the Maine and New Hampshire divisions?

A. Total Northern Demand Costs and Capacity Release and Asset Management revenues allocated to each month are then allocated to the Maine and New Hampshire divisions according to the design year total sendout for Maine and New Hampshire, which is shown in lines 61 and 62 of Schedule 21; the calculated percentages are provided in lines 65 and 66. The design year sendout quantities for the COG period as shown on lines 61 and 62 are the sendout quantities required to serve Maine and New Hampshire firm sales and transportation customers that are subject to the assigned capacity requirements under Design conditions from May 2009 through April 2010.

As shown on Line 90 of Schedule 21, 48.95% of total Northern demand costs from November 2010 through October 2011 will be allocated to New Hampshire and the remaining 51.05%, as shown on Line 81, will be allocated to Maine.

B. Allocation of New Hampshire Demand-Related Costs to Seasons

Q. Please explain how the projected annual demand-related costs that are allocated to New Hampshire are then assigned to be recovered in the 2010 / 2011 Winter period and the 2011 Summer period.

A. I have prepared Schedule 1A to show detailed support for the allocation of New Hampshire Sales Customer demand costs to months, and then to seasons.

Lines 2 through 4 of Schedule 1A summarize the Pipeline and Storage and Peaking demand costs that are allocated to the New Hampshire division, as determined in Schedule 21. Lines 13 through 23 of Schedule 1A show the calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs allocated to New Hampshire less the capacity assignment revenues from New Hampshire transportation customers. The Winter and Summer rates that will be charged to New Hampshire firm sales customers from November 2010 through October 2011 will recover: (1) the Net Pipeline Demand costs shown on Line

20, (2) the Net Storage costs shown on Line 21 and (3) the Peaking demand costs on Line 22 of Schedule 1A.[4]

Lines 27 through 41 of Schedule 1A show the calculation of Pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use demand costs.[5] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2011[6], for all firm sales classes; the Base Pipeline Demand cost that is shown on Line 40 of Schedule 1A is calculated by multiplying Base Use times the weighted average annual cost of pipeline capacity, as shown on Line 36 of Schedule 1A. Line 41 shows that Remaining Net Pipeline Demand costs for sales customers, which is the difference between total net pipeline demand costs and base use pipeline demand costs.

Lines 45 through 50 show the calculation of the PR factor that is used to allocate (a) Remaining Net Pipeline Demand costs and (b) Storage and Peaking costs related to Firm Sales customers to the twelve months, November 2010 through October 2011. Lines 52 through 57 show the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset Management revenues and (d) Interruptible margins and Delivery-to-Sales revenues to the six Peak months, November 2010 through April 2011. These PR factors are summarized by type of capacity cost in lines 61 through 65. Line 61 of Schedule 1A shows that one twelfth of the Net annual base use pipeline demand costs are allocated to each

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4 These direct demand costs are adjusted by Capacity Release and Asset Management revenues net of PNGTS litigation costs and the PNGTS refund (Line 76); Interruptible margins (Line 77); and Re-Entry Fee Credits (Line 78).

5 This separation is necessary because the SMBA allocation methodology allocates base use demand costs to seasons on a different basis than Remaining demand costs are allocated to seasons.

6 Average Projected Daily demand by class in July and August is shown in Schedule 10B, Line 48.

month and Lines 68 through 84 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peaking Months Only" allocation factors.

The total demand costs to be recovered in the 2010 / 2011 Winter COG rates, $13,712,022, is shown on Line 80, Winter total column, of Schedule 1A.

C. Allocation of New Hampshire Winter Period Demand Costs to Customer Classes

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter period are then allocated to each sales rate class.

A. The New Hampshire Division sales service base demand-related costs for each month are allocated to each sales service rate class based on that class' prorata share of total forecasted firm sendout to sales customer under normal weather conditions in that month. The remaining demand-related costs for a month are allocated to each sales service rate class based on that class' prorata share of total forecasted firm sales design day temperature sensitive demand.

I have prepared Schedule 10B to show the calculation of the factors that are used to allocate New Hampshire Division sales service Winter period base demand-related costs for each month to each sales service rate class. The firm sales forecast, shown on Lines 1 to 16; and the firm sendout forecast by class, shown on Lines 18 to 33 are used to determine daily base use, shown on Lines 35 to 48; base sendout, shown on Lines 49 to 64; and remaining sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class are used to allocate the Winter period demand costs to New Hampshire division firm sales classes.

I have prepared Schedule 10A to show the allocation of Winter period New Hampshire Net Demand costs to each firm Sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Winter period month as shown in Schedule 1A, Lines 69 through 80 and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80. The Base Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Schedule 10A and the Remaining Design Day allocators, which are used to allocate all other demand-related costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

The following table shows the location in Schedule 10A of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Schedule 10A
Base Capacity	Lines 24 through 37
Remaining Pipeline Capacity	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Capacity Release and Asset Management	Lines 86 through 102
Non-Firm Margins	Lines 104 through 120
Remaining Re-Entry Fee Credit	Lines 122 through 138
Total Non-Base Capacity Costs	Lines 140 through 154
Total Capacity Costs	Lines 156 through 174

D. Allocation of Variable Costs

Q. Please provide a description of Variable costs, and explain how Variable costs are allocated to Northern's Maine and New Hampshire divisions.

A. Variable costs include commodity costs and variable pipeline and storage costs[7] for firm sales. Mr. Wells prepared a forecast of Northern variable gas costs by month, which is provided in Schedule 6A. These variable gas costs have been allocated between the Maine and New Hampshire divisions based on each division's percentage of monthly firm normal sendout. I have prepared Schedule 22 to show the allocation of the 2010 / 2011 Winter period variable gas costs between Maine and New Hampshire.

Q. Please explain Schedule 22 in detail.

A. Lines 1 through 9 of Schedule 22 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 11, and 18 through 20 of Schedule 22. The pipeline commodity costs shown on Lines 11 and 18 are based on projected NYMEX prices as of July 22, 2010. Lines 23 through 30 show the estimated gains and losses based on the Company's time-triggered hedging program, and the projected NYMEX prices. The variable gas costs and hedging gains and losses for firm sales service that are summarized on Lines 30 and 40 are allocated to Maine and New Hampshire based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 54, 55, 59 and 60. Gains and losses based on the price triggered hedging program are shown on Lines 31 through 37; these price-triggered hedging gains and losses are directly assigned to New Hampshire. Schedule 22 also shows the allocation of (a) Commodity costs (Maine: Lines 65, 67, 68, and 69; New Hampshire: Lines 74, 76, 77, and 78); and (b) hedging

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[7] Variable costs include Pipeline usage / commodity charges, Pipeline fuel retention, Storage commodity injection and withdrawal charges, and Storage Fuel retention.

gains and losses (Lines 66 and 75) to Maine and New Hampshire. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 99 to 101); the allocation of these costs to Maine and New Hampshire (Lines 104 to 106) and the allocation of New Hampshire's allocated share of annual inventory finance costs to the Winter period, using the firm sales remaining sendout allocators (Lines 115 to 117).

I have prepared Schedule 1B to summarize the New Hampshire Division variable gas costs that were determined in Schedule 22; this attachment also shows the calculation of base and remaining commodity costs.

Q. Please explain how you calculated the inventory finance costs for underground storage and LNG resources that are included in Schedule 22, Lines 71, 80, and 89.

A. The inventory finance charges that are shown on Lines 71, 80, and 89 of Schedule 22 are derived from the inventory finance costs that are shown on Lines 99 and 100 of Schedule 22[8]. These inventory finance costs were calculated based on forecasted inventory activity calculations; I have prepared Schedule 14 to show these calculations.

Q. Why are no inventory finance costs (or "carrying costs") shown for Washington 10 Storage on Schedule 22 or calculated in Schedule 14?

A. Under its current asset management arrangement, which runs through March 2010, the Company does not incur inventory finance costs on the Washington 10 inventories, and the

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[8] Schedule 22 shows November through April commodity costs; inventory finance costs for May through October are included in the total annual costs (i.e. November through October) shown in Column N of Lines 99 through 101. Total 2010 / 2011 inventory finance costs allocated to New Hampshire, $10,094 (Line 105) are recovered in the Peak period, as shown on Line 71 of Schedule 22.

Company anticipates contracting for similar terms beginning April 1, 2011. For this reason, no inventory finance costs were calculated for Washington 10 Storage, or included in rates.

Q. Please explain how the New Hampshire Division variable gas costs for Sales customers are allocated to each firm sales class.

A. I have prepared Schedule 10C to show the allocation of New Hampshire Division variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base Sendout allocators, by rate class. Lines 22 to 49 show the allocation of the monthly New Hampshire Division Base Commodity and Base Hedging costs[9] to each rate class. Lines 51 to 70 show the calculation of the Remaining Sendout allocators, by rate class. Lines 71 to 98 show the allocation of the monthly New Hampshire Division Remaining Commodity and Remaining Hedging costs[10] to each rate class. A summary of all commodity costs allocated to New Hampshire firm sales classes is shown on Lines 99 to 140.

E. Refunds

Q. Are there any refunds included in this filing?

A. Yes, as I have previously described in this testimony, a refund from PNGTS has been included in this filing.

F. 2009 – 2010 Winter Period Reconciliation

Q. Please explain the 2009 / 2010 Winter period over and under-collections.

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9 New Hampshire Division Winter Period Base Commodity costs and Hedging costs by month are shown in Schedule 1B Lines 37 and 38.

10 New Hampshire Division Winter Period Remaining Commodity costs and Hedging costs by month are shown in Schedule 1B Lines 39 and 40.

A. The 2009 / 2010 Winter Period Cost of Gas (COG) Adjustment Reconciliation (Form III), which was filed with the Commission on July 30, 2010, provides a detailed explanation of the Winter undercollection of $2,527,403 a as of April 30, 2010

G. Miscellaneous Charges and Credits

Q. Are you projecting that Northern will receive any Re-Entry Fee Credits from transportation customers returning to sales service during the 2010 / 2011 Winter period?

A. No. Northern is not projecting any Re-Entry Fee Credits in this period.

H. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division Cost of Gas factors for the 2010 / 2011 Winter period.

A. The Summary Schedule, which is a copy of COG tariff pages 38 and 39, has been prepared to explain the calculation of the proposed 2010 / 2011 Winter COG factors. The text descriptions in the added column: (1) explain the calculations on this tariff page; and (2) provide references to other schedules for the sources of the data that appear on COG tariff Pages 38 and 39. This Summary Schedule shows the calculation of the 2010 / 2011 Winter period COG for each of Northern's three COG Rate Groups (1) Residential classes R-1 and R-2, (2) C&I Low Winter period use classes G-50, G-51 and G-52; and (3) C&I High Winter period use classes G-40, G-41 and G-42.

As shown on Summary Schedule for the 2010 / 2011 Winter period, the projected Average Cost of Gas is $1.1177 per therm (Line 83), which is the sum of the Average Direct Cost of

Gas, $0.9923 per therm (Line 74), and the Average Indirect Cost of Gas, $0.1254 per therm (Line 78).

Q. What are the major components of the 2010 / 2011 Winter Anticipated Direct Cost of Gas?

A. The table below identifies the major components of Anticipated Direct Gas Costs, as shown in the Summary Schedule.

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$1,944,296	3
2	Purchased Gas Supply Costs	$5,408,538	4
3	Storage and Peaking Capacity Costs	$13,538,806	7
4	Storage and Peaking Commodity Costs	$7,629,178	8
5	Hedging (Gain) / Loss	$1,054,446	10
6	Interruptible Costs	$0	12
7	Capacity Release, Asset Management, PNGTS Cost, PNGTS Refund	$(1,771,080)	16
8	Total Anticipated Direct Cost of gas	$27,814,277	20

Q. What are the major components of the 2010 / 2011 Winter Anticipated Indirect Cost of Gas?

A. The table below identifies the major components of Anticipated Indirect Gas Costs, as shown in the Summary Schedule.

			Summary Schedule, Line:
1	Prior Period (Over) / Undercollection	$2,527,403	24
2	Interest	$99,945	26
3	Refunds	$0	27
4	Interruptible Margins	$0	28
5	Working Capital Allowance	$(30,222)	38

6	Bad Debt Allowance	$133,747	51
7	Local Production and Storage	$686,673	53
8	Miscellaneous Overhead	$98,333	55
9	Total Anticipated Indirect Cost of Gas	$3,515,879	57

Q. Please explain the calculation of the Working Capital allowance.

The total Working Capital allowance, $(30,222) shown on Line 38 of the Summary Schedule is the sum of the current period working capital allowance, $52,847 (Line 34), plus the prior period Working Capital reconciliation balance, $(83,069) (Line 36).

Q. Please explain the calculation of the Bad Debt factor.

A. The Bad Debt allowance of $133,747 (Line 51) is the sum of the current period bad debt allowance, $136,402 (Line 49), plus the prior period Working Capital reconciliation balance, $(2,655) (Line 50).

A. Summary Analyses

Q. How does the proposed 2010 / 2011 Winter period COG rate compare with the actual 2009 / 2010 Winter period gas costs?

A. I have prepared Schedule 9 to compare the proposed 2010 / 2011 Winter average COG rate with actual 2009 / 2010 Winter gas costs. Schedule 9 indicates that the projected 2010 / 2011 Winter period average COG rate ($1.1177 per therm) is $0.0599 per therm higher than the actual 2009 / 2010 Winter period Total Adjusted Cost ($1.0579 per therm). The overall change in the proposed 2010 / 2011 Winter rate compared to the actual 2009 / 2010 Winter average cost of gas is primarily due to (1) increases in demand costs, which are largely offset by (2) decreases in commodity costs. The difference between Winter 2009 / 2010 actual average Direct Gas Costs and Winter 2010 /2011 projected average Direct Gas Costs, on Line 15 is $0.0557 per therm, which is the result of (a) an increase of $0.1437 per therm in pipeline and storage demand costs (Line 6); (b) a decrease of $0.0261 in pipeline, storage and peaking commodity costs (lines 8 and 10) and (c) a decrease of $0.0665 per therm in hedging losses (line 12). The small difference between Winter 2009 / 2010 actual average Indirect Gas Costs and Winter 2010 /2011 projected average Indirect Gas Costs, on Line 31 is $0.0043 per therm.

III. ANCILLARY RATES

A. Supplier Balancing Charge

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2010 through October 31, 2011?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2010, $0.75 per MMBtu, is unchanged from the currently effective Supplier Balancing Charge. I have prepared Schedule xx to support the updated Supplier Balancing Charge.

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. The Company plans to file a revised calculation of its 2010 / 2011 Winter Period COG to reflect updated gas cost projections and/or other information a few weeks prior to the effective date of November 1, 2010.

Q. Does this conclude your testimony?

A. Yes it does.