NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2012
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
CHRISTOPHER A. KAHL

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher A. Kahl. My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. (“Unitil Service”), a subsidiary of Unitil Corporation (“Unitil”). Unitil Service provides managerial, financial, regulatory and engineering services to the principal subsidiaries of Unitil. These subsidiaries are Fitchburg Gas and Electric Light Company d/b/a Unitil, Granite State Gas Transmission, Inc. (“Granite”), Northern Utilities, Inc. d/b/a Unitil (“Northern” or “the Company”), and Unitil Energy Systems, Inc. I am responsible for developing, providing and sponsoring certain reports, testimony and proposals filed with regulatory agencies.

Q. Please summarize your professional and educational background.

A. I have worked in the natural gas industry for almost twenty years. Before joining Unitil in January 2011, I was employed as an Analyst with Columbia Gas of Massachusetts (“Columbia”) where I had worked since 1997 in supply planning. Prior to working for Columbia, I was employed as an Analyst in the Rates and Regulatory Affairs Department of Algonquin Gas Transmission Company (“Algonquin”) from 1993 to 1997.

Prior to working for Algonquin, I was employed as a Senior Associate/Energy Consultant for DRI/McGraw-Hill.

I received a Bachelor of Sciences degree and a Masters of Arts degree in Economics from Northeastern University.

Q. Have you previously testified before the New Hampshire Public Utilities Commission or for Unitil?

A. Yes, I testified in Northern's 2011/2012 Winter Season Cost of Gas ("COG") Adjustment Proceeding, Docket No. DG 11-207.

Q. Please explain the purpose of your and other witness pre-filed direct testimony in this proceeding.

A. I, Francis X. Wells, Manager of Gas Supply for Unitil Service, and Joseph F. Conneely, Senior Regulatory Analyst for Unitil Service, are sharing the responsibility in this proceeding for supporting Northern's proposed New Hampshire 2012 Summer Season COG, effective May 1, 2012.

Mr. Wells will sponsor, describe and explain the customer demand forecast and the resulting forecasted gas sendout and gas costs he developed for the Maine and New Hampshire Divisions. He will also describe the impact of the Company's Hedging Program for the 2012 Summer Season.

Mr. Conneely will sponsor, discuss and explain the typical bill impact analyses of the proposed 2012 Summer Season New Hampshire Division COG rates, and discuss recent developments with regards to DSM.

I am sponsoring, describing and explaining the New Hampshire Division Summer COG Reconciliation filing and the calculation of the New Hampshire Division COG rates Northern proposes to bill from May 1, 2012 to October 31, 2012.

Q. How does your testimony differ from that submitted and sponsored by Mr. James Simpson on behalf of Northern in Docket No. DG 11-045, the 2011 Summer Season COG?

A. Overall, my testimony is quite similar to his with some minor edits. However, I do propose three substantive changes pertaining to the working capital, bad debt, and administrative and general ("A&G") and local production facility costs collected in this COG filing. These changes relate to proposals pending in Northern's base rate case proceeding, Docket No. DG 11-069. The Company has reflected the latest data from DG 11-069 in this filing, and does not anticipate there will be any further changes related to these issues. Also, the Company expects that an order in DG 11-069 will be issued by the Commission before the COG rates are put into effect on May 1, 2012. The Company also anticipates that the associated tariff changes and reconciliation of these costs to the date of temporary rates (August 1, 2011) will be determined in DG 11-069.

I will describe and explain these changes in detail later in my testimony.

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.

Summary Schedule	Supporting Detail to the Tariff Sheets Bad Debt, Working Capital
Schedule 1A	Allocation of New Hampshire Division Fixed Capacity Costs To Months and Seasons
Schedule 1B	New Hampshire Division Commodity Cost Analysis
Schedule 3A	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Schedule 3B	New Hampshire Division Bad Debt (Actual & Forecast)
Schedule 9	Variance Analysis / Comparison to 2011 Summer Season
Schedule 10A	Allocation of New Hampshire DivisionDemand Costs To New Hampshire Firm Sales Rate Classes
Schedule 10B	New Hampshire Division Sales and Sendout Forecast
Schedule 10C	Allocation of New Hampshire Division Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 14	Northern Utilities Inventory Activity
Schedule 21	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 22	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 23	Supporting Detail to Proposed Tariff Sheets

II. COST OF GAS FACTOR

Q. Please provide an overview of how Northern's COG related costs are allocated to the New Hampshire Division rate classes.

A. The allocation of Northern's costs to the New Hampshire Division rate classes is derived through three steps. They are as follows:

Step 1 – Allocate costs between the New Hampshire and Maine Divisions.

Step 2 - Allocate New Hampshire Division costs to the Summer and Winter seasons.

Step 3 – Allocate New Hampshire Division seasonal costs to the rate classes.

Below I provide a detailed explanation of how these three steps are conducted.

A. Allocation of Demand-Related Costs to the 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 based on the relative shares of Design Year demand[2] in that month. This MPR methodology was approved orally 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 No. DG 05-080 granting written approval of the MPR methodology.

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[1] These resources are: pipeline, storage, and peaking.
[2] For the MPR allocation process, Design Year demand is calculated as the actual demand to the Maine and New Hampshire Divisions' firm sales and assigned capacity / non-grandfathered transportation customers for the period May 2010 through April 2011, adjusted to reflect design winter conditions from November through April and normal conditions from May through October.

As I will explain in more detail below, I used the MPR methodology to allocate total Northern annual demand costs to the Maine and New Hampshire Divisions for the 2012 Winter Season, i.e. November 2011 through April 2012, and for the 2012 Summer Season, i.e. May through October 2012.

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2011 through October 2012 to the Maine and New Hampshire Divisions.

A. I have prepared Schedule 21 to explain how I calculated the MPR factors and how I used these factors to allocate total Northern annual demand costs for the period November 2011 through October 2012 ("the 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) Total 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, with the MPR allocators based on design year sendout volumes for each resource type.

(3) Total fixed capacity costs allocated to each month in section 2, above, are allocated to the Maine and New Hampshire Divisions according to design year total firm sendout as shown on Lines 58 through 91.

I note the last column of Pages 2 and 4 of Schedule 21 are descriptions of the sources of data and explanations of the calculations included in the schedule. Similar explanations are included in all attachments to my testimony.

Q. Are Northern's demand costs the same as filed in the 2011 /2012 Winter Season COG?

No. Typically, Northern's demand costs, once finalized in the Winter Season COG, are held constant throughout the Summer Season. This is because they are often stable throughout the year. However, for this Summer Season filing, demand costs have undergone significant changes and, therefore, were updated in the COG model[3]. These changes are discussed further in Mr. Wells' 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.[4] Mr. Wells also provided estimates of Capacity Release revenues, Asset Management revenues and known PNGTS litigation costs (Lines 7 through 9), all of which are recovered in the Winter Season.

[3] The resulting impact on the MPR allocator factors from these costs changes is negligible.
[4] 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 represent the capacity costs of the portion of Northern's pipeline capacity used for transporting gas to 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's fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 50 through 56 of Schedule 21. 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) 1/5th of total Capacity Release revenues are allocated to each month from November through March, as shown on Line 54; and (b) 1/6th of total Asset Management revenues, net of Northern's share of the PNGTS litigation costs, are allocated to each month from November through April, as shown on Line 55.

Q. How are the total Demand Costs and the Capacity Release and Asset Management revenues net of Northern's share of PNGTS litigation 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 net Asset Management revenues that are allocated to each month are then allocated to the Maine and New Hampshire Divisions according to the design year total sendout for the Maine and New Hampshire Divisions. This allocation is shown on lines 61 and 62 of Schedule 21; the calculated percentages are provided on lines 65 and 66. The design year sendout quantities for the COG period are the sendout quantities required to serve Maine and New Hampshire Divisions' firm sales and transportation customers that are subject to the assigned capacity requirements under design conditions from May 2010 through April 2011.

As shown on Line 91 of Schedule 21, 47.38% of Northern's total demand costs from November 2011 through October 2012 will be allocated to the New Hampshire Division and the remaining 52.62%, as shown on Line 81, will be allocated to the Maine Division.

B. <u>Allocation of New Hampshire Demand-Related Costs to Seasons</u>

Q. Please explain how the projected annual demand-related costs that are allocated to the New Hampshire Division are then assigned to be recovered in the 2011/2012 Winter Season and the 2012 Summer Season.

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

Lines 2 through 4 of Schedule 1A summarize the Pipeline, 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 represents Total Demand Costs allocated to the New Hampshire

Division less the capacity assignment revenues from New Hampshire Division transportation customers. The Winter and Summer Season rates that will be charged to New Hampshire Division firm sales customers from November 2011 through October 2012 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 shown on Line 22 of Schedule 1A.[5]

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.[6] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2012[7] for all firm sales classes; the Base Use 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 the Remaining Use 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 of Schedule 1A show the calculation of the Proportional Responsibility ("PR") allocator for all months that is used to allocate (a) Remaining Use Net Pipeline Demand costs; and (b) Storage and Peaking costs related to Firm Sales

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

6 This separation is necessary because the Simplified Market Based Allocator ("SMBA") allocation methodology allocates Base Use demand costs to seasons on a different basis than Remaining Use demand costs.

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

customers for twelve months, i.e., November 2011 through October 2012. Lines 52 through 57 show the calculation of the PR allocator that is used to allocate (c) Capacity Release and Asset Management revenues; and (d) Interruptible margins and Delivery-to-Sales revenues to the Winter Season months only. Lines 61 through 65 summarize the PR factors by type of capacity cost. Line 61 of Schedule 1A shows that 1/12th of the net annual Base Use pipeline demand costs is allocated to each month and Lines 68 through 85 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the “All Months” and “Peak Months Only” allocation factors.

The total demand costs to be recovered in the 2012 Summer Season COG rates, $858,736 is shown in Schedule 1A, on Line 80, “Summer” column.

C. Allocation of New Hampshire Summer Season Demand Costs to Customer Classes

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Summer Season 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’s prorata share of total forecasted firm sendout to sales customers under normal weather conditions in that month. The remaining demand-related monthly costs are then allocated to each sales service rate class based on that class’s 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 Summer Season base sendout and remaining sendout 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 use sendout, shown on Lines 49 to 64; and remaining use sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class are used to allocate the Summer Season demand costs to New Hampshire Division firm sales classes.

I have prepared Schedule 10A to show the allocation of Summer Season New Hampshire Division Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Summer Season month as shown in Schedule 1A, Lines 67 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[8] for firm sales. Mr. Wells prepared a forecast of Northern's 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 2012 Summer Season variable gas costs between the Maine and New Hampshire Divisions.

Q. Please explain Schedule 22.

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 Lines 18 through 20 of Schedule 22. The pipeline commodity costs shown on Lines 11 and 18 are based on projected NYMEX prices as of February 27, 2012. 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

[8] Variable costs include pipeline usage/commodity charges, pipeline fuel retention, storage commodity injection and withdrawal charges, and storage fuel retention.

gains and losses for firm sales service that are summarized on Lines 30 and 40 are allocated to the Maine and New Hampshire Divisions based on projected monthly firm sales sendout in each division (Lines 54 and 55); the allocators are shown on Lines 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 the New Hampshire Division. Schedule 22 also shows the allocation of (a) Commodity costs (Maine Division: Lines 65, 67, 68, and 69; New Hampshire Division: Lines 74, 76, 77, and 78); and (b) hedging gains and losses (Lines 66 and 75) to the Maine and New Hampshire Divisions. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 99 to 101); the allocation of these costs to the Maine and New Hampshire Divisions (Lines 104 to 106), and the allocation of New Hampshire Division's allocated share of annual inventory finance costs to the Summer Season, 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 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 the New Hampshire Division's firm sales classes is shown on Lines 99 to 140.

E. Refunds

Q. Are there any refunds included in this filing?

A. The Company is projecting no refunds in this filing.

F. 2011 Summer Season Reconciliation

Q. Please explain the 2011 Summer Season over and under-collections.

A. The 2010 / 2011 Summer Season COG Adjustment Reconciliation (Form III) filed with the Commission on January 26, 2012, provides a detailed explanation of the Summer Season over-collection of ($151,792) as of October 31, 2011.

Q. Please explain the Allocation Adjustments that appear on Schedule 4, page 1 of 2 in Schedule 15.

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

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

A. The Allocation Adjustments reflect a revision to the initial commodity allocators used to determine the commodity cost split between the Maine and New Hampshire Divisions. This split is determined by comparing the sum of each Division's actual monthly sales, company use, company managed and unaccounted-for volumes in each state. These Adjustments address two issues. First, Northern has determined that company managed volumes were not previously input and included in the Maine Division monthly total used to calculate the commodity allocators. In addition, an incorrect percentage representing unaccounted-for volumes was input for both the New Hampshire and Maine Divisions.

The exclusion of the Maine Division's company managed volumes occurred pursuant to written instructions from NiSource when the Company was first acquired by Unitil. In November, 2011, the Company concluded that the inclusion of only the New Hampshire Division's company managed volumes appeared inconsistent with proper cost allocation methods. After researching this issue, Northern has determined that these instructions from NiSource were either incorrect or based on a deficient cost allocation approach and, therefore, resulted in an inaccurate allocation of costs between the Maine and New Hampshire Divisions. The Allocation Adjustments correct for these errors by reassigning a portion of total commodity costs between the two Divisions in order to reflect a more appropriate and equitable method of assignment. This reassignment for the 2011 Off-Peak Period reconciliation reflects the difference between the initial and revised commodity costs for each month since November 2010.

Included in the reassignment is an updated unaccounted-for percentage. Previously, Northern used a fixed and outdated percentage based upon instructions received from

NiSource. The Company determined that this percentage should be updated annually and used factors based on the latest 48 month period, ending May 2011, in the Allocation Adjustments.

Northern's Maine Division Cost of Gas filing includes similar, albeit opposite, Allocation Adjustments to reflect these revisions.

G. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2012 Summer Season.

A. The Summary Schedule, which is similar to the Company's COG tariff Pages 38 and 39, has been prepared to explain the calculation of the proposed 2012 Summer COG factors. The text descriptions in the added column on page 2 and 4: (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 2012 Summer Season COG for each of Northern's three COG Rate Groups: (1) Residential classes R-1 and R-2, (2) C&I Low Summer use classes G-50, G-51 and G-52; and (3) C&I High Summer use classes G-40, G-41 and G-42.

As shown on the Summary Schedule for the 2012 Summer Season, the projected Average Cost of Gas is \$0.3371 per therm (Line 70), which is the sum of the average Total Direct Cost of Gas, \$0.3412 per therm (Line 63), and the average Indirect Cost of Gas, \$(0.0041) per therm (Line 67).

Q. What are the major components of the 2012 Summer Season 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	$481,574	3
2	Purchased Gas Supply Costs	$1,495,238	4
3	Storage and Peaking Capacity Costs	$377,162	7
4	Storage and Peaking Commodity Costs	$21,944	8
5	Hedging (Gain) / Loss	$171,582	10
6	Total Anticipated Direct Cost of gas	$2,547,501	18

Q. What are the major components of the 2012 Summer Season 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	$(151,792)	22
2	Interest	$(2,852)	24
3	Working Capital Allowance	$1,120	35
4	Bad Debt Allowance	$37,571	41
5	Local Production and Storage	$0	43
6	Miscellaneous Overhead	$85,176	45

7	Total Anticipated Indirect Cost of Gas	$(30,776)	47

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

The total Working Capital allowance, $1,120 is shown on Line 35 of the Summary Schedule is the sum of the current period working capital allowance, $2,098 (Line 32), plus the prior Summer Season Working Capital reconciliation balance, ($978) (Line 33).

Q. Has the Company proposed a Working Capital Allowance different from that used in prior Summer Seasons?

A. Yes. As indicated on Page 3 of this testimony, the Company has included a change in the Working Capital Allowance ("WCA") as proposed in Docket No. DG 11-069. The WCA in this filing is based on the Company's 2011 lead-lag study sponsored in the testimony of Mr. Paul Normand on behalf of the Company in Docket No. DG 11-069. In that study, the lag is 9.25 days which is 2.53% of a year. This percentage when multiplied by the Working Capital Carrying Charge Rate, a.k.a., the monthly prime lending rate, 3.25%, yields a WCA% of 0.0824%.

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

A. The Bad Debt allowance, $37,571 (Line 41 of the Summary Schedule), is the sum of the current period bad debt allowance, $39,068 (Line 38), plus the prior Summer Season Bad Debt reconciliation balance, ($1,497) (Line 39).

Q. Is the Company proposing to change the calculation of Bad Debt expense ?

A. Yes. As mentioned on Page 3 of this testimony, Northern has included a change in the derivation of Bad Debt in this filing consistent with its proposal in Docket No. DG 11-069.

In the past, Bad Debt has been calculated by applying a fixed Bad Debt percentage, 0.45 percent, as established in Docket No. DG 97-393, to the total Summer Season forecasted gas costs, including the reconciliations. In Docket No. DG 11-069, the Company is proposing to base its Bad Debt expense on actual Bad Debt experience which is recorded each month by the Company’s accounting department.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2012 Summer Season?

A. First, a total Bad Debt forecast for calendar year 2012 was developed for both supply and distribution. This forecast is based on the Company’s actual experience.

As shown in Schedule 3B, for the 12-months ended July 31, 2011, actual write-offs for Northern’s New Hampshire Division were $597,000. For 2012, Northern projects its annual Bad Debt expense to be $650,000. This is the same amount that was used in the Company’s 2011/2012 Peak COG filing.

The annual Bad Debt forecast was then allocated to supply (64%) and distribution (36%) based on the actual Bad Debt experience of these components over the 12-months ended July 2011. The annual Bad Debt forecast allocated to supply (i.e., $416,526) was then allocated further to the 2011 / 2012 Winter Season (91%) and 2012 Summer Season (9%) based on the actual Bad Debt experience of the respective seasons. This breakout establishes the Summer Season Bad Debt of $39,068. I have included this expense at line 38 in the Summary Schedule.

I note that the 2011 Bad Debt reconciliation used the fixed-factor method, 0.45%, to determine a Bad Debt expense and reconciled this expense to actual Bad Debt collections.

Q. Have you updated the Company's local LNG and LP production and storage capacity costs that are includable in the Summer Season COG?

A. Yes. In Docket No. DG 11-207, Northern updated these costs consistent with its proposals in Docket No. DG 11-069. The Company has since revised these costs and as indicated earlier in my testimony, this filing reflects the latest data in DG 11-069. Total local production capacity and storage costs are now established at $307,762 all of which is assigned to the Winter Season. In addition, Other Administration and General ("A&G") expenses related to local production and storage costs are $411,600. Of this amount, 20.69% is assigned to the Summer Season.

H. Summary Analyses

Q. How does the proposed 2012 Summer Season COG compare to the actual 2011 Summer Season COG?

A. I have prepared Schedule 9 to compare the proposed 2012 Summer Season average COG to the actual 2011 Summer Season COG. Schedule 9 indicates the projected 2012 Summer Season average COG rate of $0.3370 per therm is $0.3419 per therm lower than the actual 2011 Summer Season Total Adjusted COG rate of $0.6789 per therm. The overall change in the proposed 2012 Summer Season average rate compared to the 2011 Summer Season actual average rate is primarily due to decreases in pipeline demand and commodity costs, lower gas costs, an over-collection in the 2011 reconciliation, and higher projected therm sales.

III. FINAL MATTERS

Q. Will the Company propose to revise the 2012 Summer Season COG if it receives any new or updated information on gas supplier or transportation rates?

A. Yes. The Company plans to file a revised calculation of its 2012 Summer Season COG to reflect updated gas and pipeline transportation cost projections as well as any other cost information a few weeks prior to the effective date of May 1, 2012.

Q. Does this conclude your testimony?

A. Yes it does.