NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2012 / 2013
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 over twenty years. Before joining Unitil in January 2011, I was employed as an Analyst with Columbia Gas of Massachusetts[1]

[1] Columbia Gas of Massachusetts, a subsidiary of NiSource, operated under the name Bay State Gas Company until it was renamed in 2010.

("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 have testified before the Commission in the 2011 / 2012 Winter Period Cost of Gas ("COG") proceeding, Docket No. DG 11-207; and the 2012 Summer Period COG proceeding, Docket No. DG 12-068.

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

A. I, Francis Wells, Senior Energy Trader for Unitil Service, and Joseph Conneely, Senior Regulatory Analyst for Unitil Service, are sharing the responsibility of supporting the proposed New Hampshire Division 2012 / 2013 Winter Period COG and other proposed rate adjustments in this proceeding with testimony.

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. Mr. Wells will also describe the impact of the Company's Hedging Program on the 2012/ 2103 Winter Period costs.

Mr. Conneely is sponsoring, describing and explaining the calculation of the 2012 / 2013 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2012 / 2013 Winter Period COG rates.

I am sponsoring, describing and explaining the New Hampshire Division's 2011/ 2012 Winter Period Reconciliation, the calculation of the 2012 / 2013 Winter Period COG and the rates Northern proposes to charge customers from November 1, 2012 to April 30, 2013.

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 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	Bad Debt (Actual/Forecast)
Schedule 9	Variance Analysis / Comparison to 2010-2011 Winter
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 15	2011-2012 Winter Period COG Reconciliation
Schedule 18	Supplier Balancing Charge
Schedule 19	Capacity Assignment Calculations

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 Winter and Summer seasons.

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

I will 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 demand/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[2], are allocated to calendar 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[3] in that month. Initially, 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.

As I will explain in more detail below, I used the MPR methodology to allocate total Northern annual demand-related costs to the Maine and New Hampshire Divisions for the 2012 / 2013 Winter Season, i.e. November 2012 through April 2013, and for the 2013 Summer Season, i.e. May through October 2013.

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2012 through October 2013 to the Maine and New Hampshire Divisions.

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2 These resources are pipeline, storage, and peaking.

3 For the MPR allocation process, Design Year demand is calculated as the actual demand of the Maine and New Hampshire Divisions' firm sales and assigned-capacity / non-grandfathered transportation customers for the period May 2011 through April 2012, adjusted to reflect design winter effective degree day ("EDD") conditions from November through April and normal EDD conditions from May through October.

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 2012 through October 2013 ("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 (Schedule 21, pages 1 and 3), 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 in Lines 58 through 90.

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 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 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 and Asset Management revenues, which I have summarized as credits in Lines 8 and 9 of Schedule 21.

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'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

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4 The forecast of demand costs that Mr. Wells prepared is provided in Schedule 5.

54; and (b) 1/6th of total Asset Management revenues, 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, 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, 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 Divisions' firm sales and transportation customers that are subject to the assigned capacity requirements under design conditions from May 2011through April 2012.

As shown on Line 90 of Schedule 21, 46.4% of Northern's total demand costs from November 2012 through October 2013 will be allocated to the New Hampshire Division and the remaining 53.6%, as shown on Line 81, will be allocated to the Maine Division.

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

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 2012 / 2013 Winter Season and the 2013 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 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 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 2012 through October 2013 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.[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

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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).

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 that is used to allocate (a) Remaining Use Net Pipeline Demand costs; and (b) Storage and Peaking costs related to Firm Sales customers for twelve months, i.e., November 2012 through October 2013. 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 Winter Season months, November 2012 through April 2013. These PR factors are summarized by type of capacity cost in lines 61 through 65. 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.

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[6] This separation is necessary because the 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.

The total direct demand costs to be recovered in the 2012 / 2013 Winter Season COG rates, $11,941,749 is shown in Schedule 1A, on Line 80, Winter column.

Further, as shown on Page 6 of Schedule 1A, Northern's share of litigation costs that have been incurred by the Portland Natural Gas Transmission System ("PNGTS") Shippers Group ("PSG") in the PNGTS rate case, RP10-729, from August 2011 through April 2012 is $151,921.65. For the purpose of incorporating this PNGTS Litigation Expense into the COG rates, which is discussed in Mr. Well's testimony, I have reflected the New Hampshire Division's share of these costs as an offset to expected Asset Management revenues which is shown on Line 76 in Schedule 1A.

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

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter 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 costs for a month are 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 Winter Season 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 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 Winter Season demand costs to New Hampshire Division firm sales classes.

I have prepared Schedule 10A to show the allocation of Winter 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 Winter 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 / 2013 Winter 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 August 28, 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 gains and losses for firm sales service that are summarized on Lines 30 and 40 are

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

allocated to the Maine and New Hampshire Divisions 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 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 respectively. 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 Winter 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 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[9]. These inventory finance costs were calculated based on forecasted inventory activity calculations which are shown in Schedule 14.

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 2013, the Company does not incur inventory finance costs on the Washington 10 inventories, and the Company anticipates contracting for similar terms beginning April 1, 2013. For this reason, no inventory finance costs for Washington 10 Storage were calculated 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[10] to each rate class. Lines 50 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

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9 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 2011/2012 inventory finance costs allocated to New Hampshire (Line 105) are recovered in the Winter Season, as shown on Line 80 of Schedule 22.

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

Commodity and Remaining Hedging costs[11] 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. <u>Refunds</u>

Q. Are there any refunds included in this filing?

A. Yes, Northern is flowing through the refund received by Tennessee Gas Pipeline Company. The specifics of the refund are provided in Mr. Wells' testimony. This refund is being credited to customers over the 11-month period June 2012 through April 2013, and reflects a demand component of ($0.0057) per therm and a commodity component of ($0.0002) per therm. The calculations supporting these rates[12] are provided in Schedule 25.

F. <u>2011 – 2012 Winter Season Reconciliation</u>

Q. Please explain the 2011 / 2012 Winter Season over and under-collections.

A. The 2011 / 2012 Winter Season COG Adjustment Reconciliation ("Reconciliation") was initially filed with the Commission on July 31, 2012. However, since that time, Northern revised the Reconciliation to include several adjustments. The updated Reconciliation provides a detailed explanation of the 2011 / 2012 Winter Season over-collection of $(3,105,739) as of April 30, 2012. This updated Reconciliation is included in this filing.

Q. Please explain the adjustments in the updated Reconciliation.

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

[12] These calculations are identical to those initially used in Northern's 2012 Off-Peak Period CGF filing, Docket No. DG 12-68, beginning in June 2012.

A. For the updated 2011 / 2012 Winter Season Reconciliation commodity costs, Northern has applied adjustments of ($4,101,779). These adjustments pertain to an inconsistent derivation of the monthly commodity cost allocator used to allocate commodity costs to the Maine and New Hampshire Divisions during the period December 2008 (when Northern was acquired by Unitil) through October 2011. These adjustments also include the effects of correcting the derivation on interest, working capital, and bad debt expenses, as well as other limited revisions.

The monthly commodity cost allocator was initially discussed in my testimony in the 2012 Summer Season COG filing. As stated in that testimony, Allocation Adjustments were made in the 2011 Summer Season Reconciliation to reflect a revision to the initial monthly commodity cost allocators used to determine the commodity cost split between the Maine and New Hampshire Divisions for the appropriate months. 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. Previously, the Company determined that Maine Division company managed volume was not previously input and included in the Maine Division monthly sales volumes used to calculate the commodity cost allocator[13]. These input inconsistencies resulted in reallocation of actual commodity costs to the Divisions and the Company has revised this through the Allocation Adjustments. This revision reassigned a portion of Northern's total commodity costs between the Divisions.

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[13]. In addition, an revised percentage representing unaccounted-for volumes was input for both the New Hampshire and Maine Divisions.

Subsequently, on July 20, 2012, Northern submitted an extensive report[14] to the Commission regarding the Company's revision of prior commodity cost allocators and the subsequent Allocation Adjustments, in Docket No. DG 12-131. In this filing, Northern determined that the cost impact to the New Hampshire Division during the Winter Seasons from December, 2008, through October, 2011, was approximately $4.1 million in credits. Northern is currently proposing to refund this cost and has submitted similar, but inverse (debits), Allocation Adjustments to Northern's Maine Division in its 2011 /2012 Peak Period Cost of Gas Adjustment Factor filing in order be consistent with the adjustments proposed in this COG filing.

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 2012 / 2013 Winter Season?

A. Northern is projecting no Re-Entry Fee Credits in this period.

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

A. Yes. The Company is now using a Working Capital Allowance percentage ("WCA%") of 0.0824%. This percentage was approved in Northern's most recent base rate proceeding,

[14] Entitled,"Report Concerning the Allocation of Gas Supply Resources between Northern's Maine and New Hampshire Divisions and the Calculation of the Monthly Gas Supply Allocator".

Docket No. DG 11-69 (effective August 1, 2011) and used in Northern's 2012 Summer season COG filing.

I note that the 2011 / 2012 Working Capital reconciliation used the prior recovery WCA% for May through July 2011[15], and the current recovery method for August 2011 through April 2012.

Q. **How is Northern recovering Bad Debt expense in this filing?**

Northern has revised the way it recovers its Bad Debt expense by basing it on actual Bad Debt experience (i.e. actual write-offs) which is recorded each month by the Company's accounting department. This method of collection was approved in Northern's most recent base rate proceeding, Docket No. 11-69 (effective August 1, 2011) and was used and approved in the Company's 2012 Summer season COG filing.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2012 / 2013 Winter Season COG?

A. First, a total Bad Debt forecast over 12 months was developed for both supply and distribution. This forecast is based on actual experience.

As shown on Line 3 of Schedule 3B, for the 12-months ended July 31, 2012, actual write-offs for Northern's New Hampshire Division were $416,437. For 2012 / 2013, Northern projects annual Bad Debt expense to be $440,000 (Line 17).

[15] Prior WCA% was .0564%.

The annual Bad Debt forecast was then allocated to supply (66%) and distribution (34%) based on the actual Bad Debt experience of these components over the 12-months ended July 2012. This is shown on Lines 7 and 5 of Schedule 3B. The annual Bad Debt forecast for supply ($274,751), as shown on Line 6, was then allocated further to the 2012 / 2013 Winter Season (93.57%) and 2013 Summer Season (6.43%) based on the actual Bad Debt experience of the respective seasons, as shown on Lines 11 and 13. This breakout establishes the Winter Season Bad Debt of $271,636 (Line 19). I have included this expense at line 41 in the summary schedule.

Also, I've included the 2011 / 2012 Winter Season Bad Debt reconciliation (see Schedule, 15, Attachment B- Revised), an over-collection of $(142,934), in the 2012/ 2013 Winter Season COG. This amount is included in the Summary Schedule at line 42.

I note that the 2011 / 2012 Bad Debt reconciliation used the prior recovery method[16] for May through July 2011 and the current recovery method for August 2011 through April 2012.

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

A. Yes. Northern has included updated costs consistent with the Commission's approval of Northern's rate proceeding, Docket No. DG 11-069. These costs went into effect on

[16] Prior method used the fixed-factor method, 0.45%, to determine a Bad Debt expense and reconciled this expense to actual Bad Debt collections.

August 1, 2011 and are included in the derivation of Northern's 2012 / 2013 Winter Period COG rates.

Total local production capacity and storage costs are now $719,362 of which $629,506 are assigned to the winter period. These expenses include Other A&G. This amount is included in the Summary Schedule on lines 45 and 47.

H. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2012 / 2013 Winter 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 / 2013 Winter COG factors. The text descriptions in Column D, pages 3 & 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 / 2013 Winter Season COG for each of Northern's three COG Rate Groups: (1) Residential classes R-1 and R-2, (2) C&I Low Winter use classes G-50, G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42.

As shown on the Summary Schedule for the 2012 / 2013 Winter Season, the projected Average Cost of Gas is $0.7892 per therm (Line 73), which is the sum of the average Total Direct Cost of Gas, $0.8814 per therm (Line 66) and the average Indirect Cost of Gas, ($0.0922) per therm (Line 70).

Q. What are the major components of the 2012 / 2013 Winter 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	$2,023,753	3
2	Purchased Gas Supply Costs	$8,117,009	4
3	Storage and Peaking Capacity Costs	$12,098,754	7
4	Storage and Peaking Commodity Costs	$3,182,658	8
5	Hedging (Gain) / Loss	$822,275	10
6	Inventory Financing	$4,654	14
7	Capacity Release and AMA revenue net of PNGTS Litigation Costs	($2,180,758)	16
8	Total Anticipated Direct Cost of gas	$24,068,344	20

Q. What are the major components of the 2012 / 2013 Winter 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	$(3,105,739)	24
2	Interest	$(10,976)	26
3	Refunds	$(168,825)	27

4	Interruptible Margins	$0	28
5	Working Capital Allowance	$10,231	38
6	Bad Debt Allowance	$128,702	43
7	Local Production and Storage	$307,762	45
8	Miscellaneous Overhead	$321,744	47
9	Total Anticipated Indirect Cost of Gas	$(2,517,100)	49

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

The total Working Capital allowance, $10,231 is shown on Line 38 of the Summary Schedule is the sum of the current period working capital allowance, $19,823 (Line 34), plus the prior Winter Season Working Capital reconciliation balance, ($9,592) (Line 36).

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

A. The Bad Debt allowance, $128,702 (Line 43), is the sum of the current period bad debt allowance, $271,636 (Line 41), plus the prior Winter Season Bad Debt reconciliation balance, $(142,934) (Line 42).

I. Summary Analyses

Q. How does the proposed 2012 / 2013 Winter Season COG rate compare to the actual 2011 / 2012 Winter Season COG?

A. I have prepared Schedule 9 to compare the proposed 2012 / 2013 Winter Season average COG to the actual 2011 / 2012 Winter Season COG. Schedule 9 indicates the projected 2012 / 2013 Winter Season average COG rate, $0.7892 per therm, is $0.3525 per therm lower than the actual 2011 / 2012 Winter Season Total Adjusted COG, $1.1417 per therm. The overall change in the proposed 2012 / 2013 Winter Season average rate compared to the 2011/ 2012 Winter Season actual average rate is primarily due to the large prior period negative or credit balance, decreases in pipeline demand and commodity costs, a reduction in PNGTS litigation costs, as well as an increase in credits for asset management and capacity release revenues.

III. ADDITIONAL SCHEDULES AND SUPPLIER BALANCING CHARGE

Q. Are there any additional schedules included in this filing that have not been discussed?

A. Yes, Schedules 3, 19 and 23. Schedule 3 determines Northern's projected over/under-collections, balances, and interest calculations. Schedule 19 calculates the capacity assignment percentages for capacity eligible transportation customers. Schedule 23 provides additional detail to the proposed tariff sheets.

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2012 through October 31, 2013?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2012, $0.77 per MMBtu, is one cent lower than the currently effective Supplier Balancing Charge. I have prepared Schedule 18 to support the Supplier Balancing Charge.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2012 / 2013 Winter 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 / 2013 Winter 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 November 1, 2012.

Q. Does this conclude your testimony?

A. Yes it does.