NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2014
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 (“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 2013 Summer Period Cost of Gas ("COG") Adjustment Proceeding, Docket No. DG 13-083, and Northern's 2013 / 2014 Winter Period COG Adjustment Proceeding, Docket No. DG 13-257.

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

A. Joseph F. Conneely, Senior Regulatory Analyst for Unitil Service, and I are sharing the responsibility in this proceeding for supporting Northern's proposed New Hampshire 2014 Summer Period COG, effective May 1, 2014.

Mr. Conneely will sponsor, discuss and explain the pending changes to the 2014 Summer Period Local Distribution Adjustment Clause (LDAC) and the typical bill impact analyses of the proposed 2014 Summer Period New Hampshire Division COG rates.

My testimony is divided into three sections. This first section is an introduction. In the second section, 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, 2014 to October 31, 2014. In the third section I am sponsoring, describing and explaining testimony and exhibits Mr. Francis Well has offered in the past, the customer demand forecast and the resulting projected gas sendout and gas costs developed for the Maine and New Hampshire Divisions. Also, I will describe any impact of the Company's current Hedging Program on the 2014 Summer Season costs and present Northern's financial hedging plan.

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 including 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 2	Contracts Ranked on a Per-Unit Cost Basis
Schedule 3A	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Schedule 3B	New Hampshire Division Bad Debt (Actual & Forecast)
Schedule 5	Demand Cost Forecast
Attachment	Rate Cost Support
Schedule 6A	Commodity Cost Forecast
Schedule 6B	Detailed City-gate Cost Calculations
Schedule 9	Variance Analysis / Comparison to 2013 Summer Period
Schedule 10A	Allocation of New Hampshire Division Demand 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 11A	Normal Year Sendout Volume
Schedule 11C	Capacity Utilization
Schedule 13	Load Migration from Sales to Transportation
Schedule 14	Northern Utilities Inventory Activity
Schedule 15	2013 Summer Period Reconciliation
Schedule 20	Annual Hedging Program
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
Schedule 25	Supplier Refunds

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. Northern allocates costs between Winter and Summer Periods as well as among customer classes through the Simplified Market Based Allocation ("SMBA") method. The SMBA approach assigns costs over a three step process. These steps 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 Periods.

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 by the Commission in its Order No. 24,627 in Docket No. DG 05-080.

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 2014 Winter Period, i.e. November 2013 through April 2014, and for the 2014 Summer Period, i.e. May through October 2014.

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2013 through October 2014 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 2013 through October 2014 ("the COG Period") to the Maine and New Hampshire Divisions. Schedule 21 is arranged in three major sections:

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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 2012 through April 2013, adjusted to reflect design winter conditions from November through April and normal conditions from May through October.

(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 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 all attachments to my testimony.

Q. Are Northern's demand costs shown on Attachment Schedule 21 the same as filed in the 2013 /2014 Winter Season COG?

A. Typically, demand costs in the Summer Season are the same because these costs are often stable throughout the year. However, during the winter of 2013 / 2014 Northern made a mid-season adjustment to its Maine Division's cost of gas rates. This change was made, in part, due to the use of an updated Canadian exchange rate. For consistency, Northern is applying this updated exchange rate to the New Hampshire Division's cost of gas filing. However, I note this change in demand costs had essentially no impact on the MPR Allocation percentages.

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. Also included are estimates of Northern's Capacity Release and Asset Management revenues (Lines 8 and 9), all of which are recovered in the Winter Period.

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 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, 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 2012 through April 2013.

As shown on Line 90 of Schedule 21, 47.23% of Northern's total demand costs from November 2013 through October 2014 will be allocated to the New Hampshire Division and the remaining 52.77%, 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 2013 / 2014 Winter Period and the 2014 Summer Period.

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 Period rates that will be charged to New Hampshire Division firm sales customers from November 2013 through October 2014 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.[3]

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.[4] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2014[5] 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.

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[3] 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).

[4] 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.

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

Lines 45 through 50 of Schedule 1A show the calculation of the MPR 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 customers for twelve months, i.e., November 2013 through October 2014. Lines 52 through 57 show the calculation of the MPR 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 Period months only. Lines 61 through 65 summarize the MPR 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 direct demand costs to be recovered in the 2014 Summer Period COG rates, $912,730 is shown in Schedule 1A, on Line 80, "Summer" column. These costs, in addition to $78,440 of indirect demand costs, as shown in Schedule 1A, Line 85, are recorded as Summer Period capacity related costs, and are collected in six even increments.

C. <u>Allocation of New Hampshire Summer Period Demand Costs to Customer Classes</u>

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Summer 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'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 Period 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 Period demand costs to New Hampshire Division firm sales classes.

I have prepared Schedule 10A to show the allocation of Summer Period 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 Period month as shown in Schedule 1A, Lines 67 through 80, and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80[6]. 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.

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[6] Additional demand cost allocation support is provided in Schedule 23.

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. <u>Allocation of Variable Costs</u>

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. 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 2014 Summer Period 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. The projected variable costs by month and by type of gas supply resource

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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.

are shown on Line 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 28, 2014. 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 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 Period, using the firm sales remaining sendout allocators (Lines 115 to 117)[8].

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8 Schedule 14 provides the forecasted storage inventory and related finance costs that are allocated to each division in Schedule 22. However, these charges are collected only during Winter Season.

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[9]. 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 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[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?

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[9] Additional commodity cost allocation support is provided in Schedule 23.

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

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

A. Yes, in May of 2013, Northern received a refund from the Portland Natural Gas Transmission System ("PNGTS") in accordance with the Federal Energy Regulatory Commission's Order on rehearing in the pipeline's rate case proceeding, Docket RP08-306. Northern began flowing this refund back to its customers, over a 12 month period, in the 2013 / 2014 Peak Period COG. The remainder of this refund is being flowed through to Northern's sales customers during the 2014 Summer Season. I have prepared Schedule 25 to show the calculation of the refund.

F. <u>2013 Summer Period Reconciliation</u>

Q. Please explain the 2013 Summer Period over and under-collections.

A. The 2013 Summer Period COG Adjustment Reconciliation (Form III) filed with the Commission on February 3, 2014, provides a detailed explanation of the Summer Period under-collection of $394,545 as of October 31, 2013. I have provided this Reconciliation as Schedule 15 in this filing.

G. <u>Cost of Gas Factor</u>

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2014 Summer Period.

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 2014 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 2014 Summer Period 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 2014 Summer Period, the projected Average Cost of Gas is $0.6833 per therm (Line 73), which is the sum of the average Total Direct Cost of Gas, $0.6222 per therm (Line 66), and the average Indirect Cost of Gas, $0.0611 per therm (Line 67).

Q. What are the major components of the 2014 Summer Period 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	$533,794	3
2	Purchased Gas Supply Costs	$3,143,535	4
3	Storage and Peaking Capacity Costs	$378,936	7
4	Storage and Peaking Commodity Costs	$29,861	8
5	Hedging (Gain) / Loss	$0	10
6	Total Anticipated Direct Cost of gas	$4,086,126	20

Q. What are the major components of the 2014 Summer Period 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) / Under-collection	$394,545	24
2	Interest[12]	$10,204	26
3	Refunds	$(105,725)	27
4	Working Capital Allowance	$4,226	38
5	Bad Debt Allowance	$19,792	43
6	Local Production and Storage	$0	45
7	Miscellaneous Overhead	$78,440	47
8	Total Anticipated Indirect Cost of Gas	$401,483	49

Q. How is Northern's current period Working Capital Allowance derived?

A. Northern's Working Capital Allowance Percentage, 0.0824%, is multiplied by the projected direct cost of gas in order to determine the Working Capital Allowance $3,365 (line 34). This is then added to the prior Summer Period Working Capital Reconciliation balance, $861, (Line 36) for a total Working Capital Allowance of $4,226 (Line 38).

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

[12] Support for the interest calculation is provided in Schedule 3A.

A. The Bad Debt allowance, $19,792 (Line 43 of the Summary Schedule), is the sum of the current period bad debt allowance, $22,890 (Line 41), plus the prior Summer Period Bad Debt Reconciliation balance, ($3,098) (Line 42).

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2014 Summer Period?

A. First, a total Bad Debt forecast for calendar year 2014 was developed for both supply and distribution. This forecast is based on the Company's actual experience.

As shown in Schedule 3B, Line 3, for the 12-months ended July 31, 2013, actual write-offs for Northern's New Hampshire Division were $360,081. For 2014, Northern projects its annual Bad Debt expense to be $500,000 (Line 17). This is the same amount that was used in the Company's 2013 / 2014 Winter Period COG filing.

The annual Bad Debt forecast was then allocated to supply (57.21%) and distribution (42.79%) based on the actual Bad Debt experience of these components over the 12-months ended July 2013. The annual Bad Debt forecast allocated to supply (i.e., $286,059) was then allocated further to the 2013 / 2014 Winter Period (92.00%) and 2014 Summer Period (8.00%) based on the actual Bad Debt experience of the respective Periods. This breakout establishes the 2014 Summer Period Bad Debt of $22,890 (Schedule 3B, Line 20).

Q. What are the Company's local LNG and LP production and storage capacity costs that are included in the Summer Period COG?

A. In Docket No. DG 11-069, total local production capacity and storage costs were established at $307,762 all of which is assigned to the Winter Period. In addition, Other Administration and General ("A&G") expenses related to local production and storage costs are $411,601. Of this amount, 19.06%, or $78,440 is assigned to the Summer Period[13].

H. Summary Analyses

Q. How does the proposed 2014 Summer Period COG compare to the actual 2013 Summer Period COG?

A. I have prepared Schedule 9 to compare the proposed 2014 Summer Period COG to the actual average 2013 Summer Period COG. Schedule 9 indicates the projected 2014 Summer Period average COG rate of $0.6833 per therm is $0.0243 per therm higher than the actual 2013 Summer Period Total Adjusted COG rate of $0.6590 per therm. The overall change in the proposed 2014 Summer Period average rate compared to the 2013 Summer Period actual average rate is primarily due to a higher prior period under-collection of costs in the 2014 filing, and off-system sales recorded during the 2013 summer season.

III. FORECAST OF CUSTOMER DEMAND AND GAS SUPPLY COSTS

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[13] In Northern's current base rate proceeding, Docket No. DG 13-086, the Company filed a settlement, effective May 1, 2014, that includes a change in these expenses; $420,658 for production and storage costs, and $512,686 for miscellaneous and other A&G expenses. If the Settlement is approved, Northern will apply the updated expenses to the general ledger and apply these expenses in calculating the 2014 Summer Season reconciliation.

A SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries for the Company's residential, small commercial and larger industrial/commercial classes, the Company has utilized time-series techniques to develop two forecast models: use-per-meter and the number of meters. The growth rates for customers (meters) and use-per-meter from these models are applied to the most recent data normalized for weather; the forecast monthly billed deliveries for each customer class was calculated by multiplying forecast customers times forecast use-per-customer. Forecast deliveries for the large commercial customers with special contracts were developed separately for each of these customers.

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. Table 1, below, provides a summary of the company's forecast of total billed distribution deliveries for the upcoming 2014 Summer Period.

Table 1. 2014 Summer New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years

Month	2014 Forecast[1]	2013 Actual[2]	2014 minus 2013	Percent Change	2012 Actual[2]	2014 minus 2012	Percent Change
May	465,075	484,053	-18,977	-3.9%	429,260	35,815	8.3%
Jun	377,322	377,016	306	0.1%	348,153	29,169	8.4%
Jul	327,299	310,556	16,744	5.4%	300,179	27,121	9.0%
Aug	329,697	320,392	9,305	2.9%	302,241	27,456	9.1%
Sep	328,757	328,259	498	0.2%	303,338	25,419	8.4%
Oct	393,389	396,543	-3,154	-0.8%	361,315	32,074	8.9%
Winter	2,221,539	2,216,817	4,722	0.2%	2,044,485	177,054	8.7%

Note 1: Company Forecast.
Notes 2 and 3: Actual Weather-Normalized Data.

A detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2014 Summer Period is provided in Attachment 1 to Schedule 10B. Page 1 of Attachment 1 to Schedule 10B provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2014 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2013 and 2012 Summer Periods. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment 1 to Schedule 10B provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. Please provide an overview of the process for converting the forecast distribution deliveries forecast to a sales service deliveries forecast.

A. In order to prepare this COG filing, Northern reduced its total distribution deliveries forecast to reflect only the distribution deliveries to those customers taking sales service. The commodity cost forecast, presented later, reflects only the projected costs to serve Northern's sales service obligations. Customers electing transportation-only service reflect a substantial portion of Northern's total distribution deliveries, and the cost of gas for these customers is determined by the private contractual arrangements between the customers and their retail marketer[14].

Northern estimated the percentage of total distribution deliveries to be supplied through Sales Service ("Sales Service Percentage") for each rate class based upon the most recent 12 months of historical distribution and sales service deliveries data available at the time of the analysis.

The billed distribution deliveries forecast is converted to a calendar-month distribution deliveries forecast by calculating a five-year average ratio of monthly sendout to seasonal sendout and applying these monthly ratios to the forecast billed deliveries. In the case of G52 and Special Contracts, the bill month is the calendar month, so no adjustments to these rate classes were made. The city-gate supply required to serve the Sales Service deliveries was then calculated.

Attachment 2 to Schedule 10B provides back-up calculations for this analysis. On Pages 1 and 2 of Attachment 2 to Schedule 10B, the calculation of the calendar month and billed sales service deliveries by rate class is presented, using the methodology discussed above. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire Division.

[14] Schedule 13 provides the amount of load that is comprised of sales vs. transportation service for the 2013-2014 year.

On Page 3 of Attachment 2 to Schedule 10B, calculations of the city-gate receipts are presented. First, Company Use is estimated[15] by multiplying the forecasted Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, Company Use is added to the total Calendar Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use").

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. Table 2, below, provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries and City-Gate Receipts to meet the Sales Service Deliveries[16] for the upcoming Summer Period. The detailed calculations can be found in Attachment 2 to Schedule 10B.

Table 2. Required City-Gate Receipts Summary

Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
May-14	385,692	132,838	133,613
Jun-14	335,390	94,468	95,019
Jul-14	305,099	82,453	82,934
Aug-14	316,825	86,137	86,639
Sep-14	328,970	95,008	95,562
Oct-14	443,803	166,199	167,169
Off-Peak	2,115,778	657,102	660,936

[15] Company use estimates are based recent actual data and provided in the 2013-2014 Peak Period Filing as Attachment 3 to Schedule 10B.

[16] The term "City-Gate Receipts to meet the Sales Service Requirements", refers to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

B. NORTHERN'S GAS SUPPLY PORTFOLIO

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

A. Table 3, below, provides an overview of the sources of supply available to Northern.

Table 3. Northern Capacity by Supply Source (Dth per Day)

Supply Source	2013-2014 Winter	2014 Summer
Tennessee Production	13,109	13,109
Chicago City-Gates Supply	6,434	6,434
Algonquin Receipt Points Supply	1,251	1,251
Niagara	2,327	2,327
PNGTS	1,096	1,096
PNGTS Delivered	897	0
Lewiston City-Gate Baseload Supply	6,500	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Supply 1	14,948	0
Peaking Supply 2	5,000	0
Peaking Supply 3	24,913	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**122,004**	**36,861**

The above capacity makes use of many contracts in getting gas supplies delivered to Northern. The Company's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited ("TransCanada"), Vector Pipeline L.P. ("Vector"), Union Pipelines Ltd. ("Union"), Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Washington 10 Storage Corporation ("Washington 10" or "W10"), Tennessee and Texas Eastern. Northern's gas supply portfolio includes three separate peaking supply agreements, each providing Northern the option to purchase supply delivered to Tennessee Zone 6, PNGTS or Maritimes meters. These peaking supply arrangements were procured through a Request-For-Proposals and are for one winter in duration. These Peaking Supply contracts will not be available during the 2014 Summer Period.

Also, Northern owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 10,000 Dth per day and storing approximately 12,000 Dth of LNG. Northern plans to replace its current LNG Contract (which ends 3/31/2014) in order to supply this facility.

Finally, the gas supply portfolio consists of an exchange agreement with Columbia Gas of Massachusetts (formerly known as Bay State Gas Company).

Q. Has the Company entered into any long-term releases of capacity?

A. Yes. Effective May 1, 2009, Northern released Texas Eastern Contract 800384 for the remaining terms of the agreement, which is through October 31, 2017. This release is at the maximum allowable rates, thus fully recovering the costs of the released contract.

Q. Please describe the Company's process for procuring its gas commodity supplies.

A. Northern's practice is to secure its gas commodity supplies through annual requests-for-proposal ("RFP") for terms beginning April 1 and running through March 31 each year. Northern submitted its annual RFP for the delivery period beginning April 1, 2014 through March 31, 2014, on February 7, 2014. This RFP sought asset management proposals for Northern's Chicago, Algonquin Receipts, Niagara, Tennessee Production and Washington 10 capacity paths. Northern also sought baseload supply through this RFP. The Company typically enters into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers. This summer, Northern plans to issue an RFP for replacement peaking supplies.

C. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to calculate the 2014 Summer COG.

A. The following cost estimates were used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities for the period November 2013 through October 2014

- New Hampshire Division Capacity Assignment program demand revenues for the period November 2013 through October 2014
- Northern's commodity costs for the period May 2014 through October 2014
- Gains and losses due to Northern's financial hedging program for the period May 2014 through October 2014

The figures presented in my testimony here relate to total company costs, inclusive of both the New Hampshire and Maine Divisions.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 4, below, titled, "Estimated Gas Supply Demand Costs."

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2013 through October 31, 2014			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,358,833	Sch 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 24,059,732	Sch 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Sch 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,725,723	Sch 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 1,053,750	Sch 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,956,197)	Sch 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 26,278,687	Sum Lines 1 through 6.

The detailed calculations of this demand cost forecast are presented in Schedule 5A. Page 1 of Schedule 5A provides the summary data presented here in Table 4. On page 2 of Schedule 5A, the annual demand cost forecast for Northern's portfolio of transportation contracts is calculated. On page 3 of the Schedule, each transportation contract is designated as a pipeline, storage or peaking resource and allocated transportation costs based upon these designations. Pages 4 and 5 of the Schedule provide calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of the Schedule, capacity release and asset management revenue the Company expects to receive for the 2013-2014 Gas Year are forecast. Support for the transportation and storage demand rates used in Schedule 5A are found in the Attachment to Schedule 5A[17].

Q. Please provide Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. The 2013-2014 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $3,321,511[18]. No changes have been made to this calculation since the 2013-2014 Winter Season filing.

Q. Please describe Northern's process for forecasting commodity costs.

A. The Company's commodity cost forecast is based on Northern's projected city-gate receipts for sales service customers, which were calculated in Attachment 2 to Schedule

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[17] The 2013- 2014 Winter Period filing provides an expanded version of Attachment 5A that includes tariff rate pages and supplier contracts. This filing does include support for pipeline rates reflecting the updated Canadian exchange rate.
[18] Support for this number is provided in the 2013-2014 Revised Peak Period Filing, Revised Schedule 5B, Page 1.

10B, and the supply sources available to Northern[19]. Supply prices are forecasted at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. Variable fuel retention factors and rates for Northern's transportation and storage contracts are also forecasted. The Sendout® natural gas supply cost model was then used to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.

Q. Please present the Company's commodity cost forecast for the 2014 Summer Period.

A. Northern's commodity cost forecast for the upcoming Summer Period is summarized in Table 5, below[20].

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2014 through October 2014

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Algonquin Receipts	$293,758	61,648	$4.765
Tenn Zone 4 Spot	$1,395,970	292,944	$4.765
Tennessee Production	$3,905,343	815,730	$4.788
Iroquois Receipts	$153,216	31,054	$4.934
Chicago	$418,154	83,667	$4.998
Niagara	$14,524	2,872	$5.057
Lewiston Baseload	$240,870	46,500	$5.180
LNG	$59,172	8,280	$7.146
Total Delivered Commodity Cost	$6,481,006	1,342,695	$4.827

In summary, projected delivered commodity costs equal approximately $6.5 million at an average delivered rate of $4.827 per Dth. In support of this forecast, Schedule 6A shows

[19] Diagrams of capacity paths along with details for each supply source were provided in Schedule 12 in the 2013-2014 Peak Period filing.
[20] This table is also provided in Schedule 2.

the monthly forecasted commodity cost by supply option[21]. Page 1 of this Schedule provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of this Schedule provides monthly delivered volumes (Dth) by supply source[22]. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

The detailed calculations of the delivered commodity cost are found in Schedule 6B. It provides, for each supply source, detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by Northern in order to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support for the supply prices and variable transportation charges in Schedule 6B are found in the Attachment to Schedule 5A.

Q. Are there any financial hedges for the 2014 Off-peak Period?

A. There are no hedges for this time period resulting from the current Hedging Program.

D. NORTHERN HEDGING PLAN FOR NOVEMBER 2015 THROUGH APRIL 2016

Q. Please provide an update as to the status of Northern's financial Hedging Program.

A. During 2013, changes were made and approved to Northern's Hedging Program such that purchases of natural gas futures contracts have been replaced with purchases of options

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[21] Schedule 11C provides the capacity utilization of the resources listed in Schedule 6A.
[22] A modified version of Page 2 of Schedule 6A is provided in Schedule 11A.

contracts on futures contracts[23]. The new program's design continues the previous method used to determine the required number of financial hedges, which provides for 70 percent of expected supply requirements at a fixed or capped price using both physical and financial resources. The period covered by the new program's design includes only the traditional gas winter months of November through March, with purchases of option contracts for each future month being executed 18 months prior to contract expiration. The new Hedging Program uses a budget approach to determine option and strike prices whereby the budget is established as a percentage of the futures price at the time of purchase. The Company initially proposed a budget of 2.5 percent of the futures price at the time of purchase, subject to review each year when it files its Hedging Program plan with the spring cost of gas factor filing.

Q. Has Northern developed a plan for financial hedging the period of November 2015 through March 2016?

A. Yes. Page 1 of Attachment Schedule 20 provides the Hedging Program plan for 2015-16. As shown, option purchases would be made beginning in late April 2014 for the winter month of November 2015 and continue for five months until late August 2014 when the contracts for March 2016 would be purchased. A total of 195 contracts are scheduled to be purchased, which total covers both the Maine and New Hampshire Divisions. Northern proposes to retain the metric of 2.5 percent of futures price to determine the

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[23] The new program design was approved for the Maine Division in Docket No. 2012-448 and for the New Hampshire Division in Docket DG 13-119.

option budget. Using recent market prices and a 2.5 percent budget, the expected cost would be $209,215 and strike prices would range from $5.55 to $7.00.

Q. Are there any impacts from this new Hedging Program on proposed rates covered by this filing, May 2014 through October 2014?

A. No. Summer period hedging was discontinued as part of the new Hedging Program design, and this coming summer is the first summer for which no financial hedging has been conducted.

E. FERC PIPELINE RATE CASE UPDATE

Q. Please list the interstate pipeline rate cases currently affecting Northern.

A. Northern is currently involved in the following pipeline rate cases at the FERC:

- Portland Natural Gas Transmission System (“PNGTS”) has filed rate cases under FERC Docket Nos. RP08-306 (“2008 PNGTS Rate Case”) and RP10-729 (“2010 PNGTS Rate Case”) that have not been fully resolved.

- TransCanada Pipelines Limited filed an application with the NEB on December 20, 2013, seeking approval of a settlement agreement (“Settlement”) that TransCanada reached with the three largest Canadian local distribution companies (“Canadian LDCs”), which would increase tolls on Northern’s contracts with TransCanada by approximately 50 percent above the tolls approved by the National Energy Board (“NEB”) in its March 27, 2013, decision on the 2013 and

2014 TransCanada Tolls Application ("NEB Order"), which had been filed on September 1, 2011.

Q. Please provide an update to the 2008 PNGTS Rate Case.

A. On May 21, 2013, PNGTS refunded reservation charges that were paid subject to refund, including interest, to Northern. As I mentioned earlier in my testimony, this refund is being flowed through to customers in the 2013-2014 Winter Season filing as well as in this proposed Summer Season filing. However, PNGTS has appealed FERC's decision and the appeal has not yet been ruled on.

Q. Please provide an update on the 2010 PNGTS Rate Case.

A. FERC issued its Order on the 2010 PNGTS Rate Case Initial Decision ("Opinion 524") on March 21, 2013. Requests for Rehearing on Opinion 524 were filed by the Portland Shippers Group ("PSG") and PNGTS in April 2013. There has been no further activity and Northern continues to await FERC action on these Requests for Rehearing.

Q. Does the proposed COG reflect the rate increases proposed in the 2010 PNGTS Rate Case?

A. Yes. Consistent with the Winter Season filing, the forecast gas supply demand costs include costs projected at the 2010 PNGTS filed rates.

Q. Please provide an update of the TransCanada Application for approval of the Settlement with the Canadian LDCs.

A. On December 20, 2013, TransCanada filed with the NEB for approval of a Settlement with the Canadian LDCs. The Settlement involves segmenting the eastern portion of the mainline from the western portion of the mainline, with increased tolls along the eastern portion reflecting a premium to cover revenue shortfalls on the western portion for the period of 2015-2020. Post 2020, the eastern portion tolls would be separate from the western portion. Upon approval, TransCanada would be willing to construct new short haul transportation capacity in the east, but would require 15 year commitments. In response to the NEB order issued in March 2013, TransCanada had taken the position they would not expand its system so long as any capacity remained unsubscribed, including capacity on the western portion of the system.

The impact of the proposed Settlement would be to undo the rate certainty that had been established under the NEB Order, which provided for multi-year fixed tolls through December 31, 2017, which were significantly lower than the tolls in effect prior to the 2012 and 2013 TransCanada Tolls Application. Instead, the Settlement introduces higher rates for the last three years of this period and beyond. Toll increases would be approximately 50 percent above tolls determined in the NEB Order. In addition, TransCanada would retain its new enhanced pricing flexibility in discretionary markets that were provided for under the NEB Order. TransCanada would also gain the right to unilaterally require shippers, including Northern, to extend agreements whenever TransCanada plans to invest to expand its pipeline to meet new contract requirements. Currently, Northern has the right to extend or terminate its contracts upon two years notice prior to the current termination date. Northern monitors and participates in the

NEB process for review of the Settlement as a member of Alberta Northeast Gas, Limited ("ANE").

Q. What is the basis of TransCanada Tolls reflected in the proposed COG?

A. The forecasted TransCanada rates continue to reflect TransCanada's approved 2013 and 2014 tolls as approved in the NEB Order since new tolls under the Settlement are still under review and were filed for implementation beginning on January 1, 2015.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2014 Summer Period 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 2014 Summer Period 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, 2014.

Q. Does this conclude your testimony?

A. Yes it does.