NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 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 ("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 2012 Summer Period Cost of Gas ("COG") Adjustment Proceeding, Docket No. DG 12-068, and Northern's 2012 / 2013 Winter Period COG Adjustment Proceeding, Docket No. DG 12-273.

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 2013 Summer Period COG, effective May 1, 2013.

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 2013 Summer Period.

Mr. Conneely will sponsor, discuss and explain the calculation of the 2013 Summer Period Local Distribution Adjustment Clause (LDAC) and the typical bill impact analyses of the proposed 2013 Summer Period New Hampshire Division COG rates.

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, 2013 to October 31, 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 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 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 2012 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 14	Northern Utilities Inventory Activity
Schedule 15	2012 Summer Period Reconciliation
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. 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

[1] These resources are: pipeline, storage, and peaking.

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.

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 2013 Winter Period, i.e. November 2012 through April 2013, and for the 2013 Summer Period, 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.

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.

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[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 2011 through April 2012, adjusted to reflect design winter conditions from November through April and normal conditions from May through October.

(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 the same as filed in the 2012 /2013 Winter Period COG?

Yes. Northern's demand costs, once finalized in the Winter Period COG, are usually held constant throughout the Summer Period. This is because they are often stable throughout the year. However, Northern will revise the demand costs if large increases are expected due to rate case filings by interstate pipelines. For the 2013 Summer Period, no large rate case impacts are expected.

Q. Which of the Schedules that you are sponsoring remain unchanged from the 2012 / 2013 Winter Period COG filing due to the demand costs being unchanged?

A. Schedules 21 and 1A.

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

A. Lines 3 through 6 of Schedule 21 show the total Northern annual projected demand costs for Pipeline, Storage, and Peaking resources; these forecasted demand costs were provided to me by Mr. Wells.[3] Mr. Wells also provided estimates of Capacity Release revenues and Asset Management revenues (Lines 7 and 8) and known PNGTS litigation costs (Page 6, Line 3), 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

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

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, 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 2011 through 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. <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 2012 / 2013 Winter Period and the 2013 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 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 shown on Line 22 of Schedule 1A.[4]

Lines 27 through 41 of Schedule 1A show the calculation of pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use

[4] 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.[5] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2013[6] 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 customers for twelve months, i.e., November 2012 through October 2013. 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 Period 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.

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5 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.

6 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 2013 Summer Period COG rates, $1,049,948 is shown in Schedule 1A, on Line 80, "Summer" column. These costs, in addition to $89,856 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. The Base Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Schedule 10A and the Remaining Design Day allocators, which are used to allocate all other demand-related costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

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

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

D. Allocation of Variable Costs

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

A. Variable costs include commodity costs and variable pipeline and storage costs[7] for firm sales. Mr. Wells prepared a forecast of Northern'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 2013 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, 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 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, 2013. 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

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

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].

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

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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.

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

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. What is the status of the Tennessee Gas Pipeline ("Tennessee") refunds?

A. Northern is currently flowing through the refund received by Tennessee Gas Pipeline Company. The specifics of the refund were provided in Mr. Well's testimony in Docket No. DG 12-273. This refund is being credited to customers over the 11-month period June 2012-April 2013. Northern proposes to flow any under/over-collections as of April 30, 2013 through the 2013 Summer Period Reconciliation.

F. 2012 Summer Period Reconciliation

Q. Please explain the 2012 Summer Period over and under-collections.

A. The 2012 Summer Period COG Adjustment Reconciliation (Form III) filed with the Commission on January 29, 2013, provides a detailed explanation of the Summer Period under-collection of $147,647 as of October 31, 2012. I have provided this Reconciliation as Schedule 15 in this filing.

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

Q. Are there any changes to the format of the 2012 Summer Period Reconciliation?

A. Yes, Form III, Schedule 4 has been expanded to include New Hampshire Division volumes and per unit costs in addition to New Hampshire total costs which are currently provided in the Schedule. Further similar information is provided for the Maine Division and for Northern in total.

Q. Please explain the adjustments to the beginning balances that appear on Schedule 2, Attachment A and Attachment B in Schedule 15.

A. The adjustments reflect a revision to the initial commodity allocators used to determine the commodity cost split between the Maine and New Hampshire Divisions during the 2009 and 2010 Summer Periods. Adjustments related to commodity allocators were initially proposed, and subsequently approved, in the 2012 Summer Period filing, Docket No. DG 12-068. In that filing, the Company determined that an adjustment of approximately $9,623 needed to be charged to New Hampshire customers due to an adjustment to the commodity allocators during the 2011 Summer Period. In the summer of 2012, Northern completed a thorough analysis of the commodity allocator issue for the New Hampshire PUC in Docket No. DG 12-131. In that study, Northern determined that additional adjustments to the commodity allocators were required for 2008 and 2009. These adjustments resulted in New Hampshire Division customers receiving a charge of

$3,054 for the 2008 Summer Period and a credit of ($31,954) for the 2009 Summer Period. In total, the adjustments for both Summer Periods results in a credit of ($28,900)[11].

Q. Are there other costs/credits included in the 2012 Summer Period Reconciliation adjustments in addition to the ones presented in DG 12-131?

A. Yes. In Schedule 2, there is a ($889) credit reflecting additional accrued interest tied to the commodity allocator adjustments[12]. Also in Schedule 2, there is a $15,032 adjustment pertaining to the implementation of the new Allowance for Local Production and Storage resulting from Northern's most recent base rate case proceeding, Docket No. DG 11-069. Attachment A (Working Capital) shows an adjustment of $569 for the rate case Allowance change. Attachment B (Bad Debt) shows an adjustment of $1,049 for the rate case Allowance change as well as a $12 charge reflecting additional interest expenses[13].

G. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2013 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 2013 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

[11] Provided in DG 12-131, Schedule 1, Page 1, Line 47. Includes Working Capital, Bad Debt and interest expenses.
[12] Credit is added to charges/credits in DG 12-131, Schedule 1, Page 1, Lines 30, 32, 39 and 41 to derive adjustment listed on Schedule 2.
[13] Charge is added to the charges / credits in DG 12-131, Page 1, Lines 35, 44 and 45 to derive adjustment listed on Attachment B.

that appear on COG tariff Pages 38 and 39. This Summary Schedule shows the calculation of the 2013 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 2013 Summer Period, the projected Average Cost of Gas is $0.5553 per therm (Line 70), which is the sum of the average Total Direct Cost of Gas, $0.5233 per therm (Line 63), and the average Indirect Cost of Gas, $0.0320 per therm (Line 67).

Q. What are the major components of the 2013 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	$684,707	3
2	Purchased Gas Supply Costs	$2,920,655	4
3	Storage and Peaking Capacity Costs	$365,241	7
4	Storage and Peaking Commodity Costs	$21,832	8
5	Hedging (Gain) / Loss	$(1,664)	10
6	Total Anticipated Direct Cost of gas	$3,990,771	18

Q. What are the major components of the 2013 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	$147,647	22
2	Interest	$2,290	24
3	Working Capital Allowance	$4,576	35
4	Bad Debt Allowance	$(617)	41
5	Local Production and Storage	$0	43
6	Miscellaneous Overhead	$89,856	45
7	Total Anticipated Indirect Cost of Gas	$243,752	47

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 $3,287 (line 32). This is then added to the prior Summer Period Working Capital Reconciliation balance, $1,289, (Line 33) for a total Working Capital Allowance of $4,576 (Line 35).

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

A. The Bad Debt allowance, ($617) (Line 41 of the Summary Schedule), is the sum of the current period bad debt allowance, $18,660 (Line 38), plus the prior Summer Period Bad Debt Reconciliation balance, ($19,277) (Line 39).

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2013 Summer Period?

A. First, a total Bad Debt forecast for calendar year 2013 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, 2012, actual write-offs for Northern's New Hampshire Division were $416,437. For 2013, Northern projects its annual Bad Debt expense to be $440,000 (Line 17). This is the same amount that was used in the Company's 2012 / 2013 Winter Period COG filing.

The annual Bad Debt forecast was then allocated to supply (65.98%) and distribution (34.02%) based on the actual Bad Debt experience of these components over the 12-months ended July 2012. The annual Bad Debt forecast allocated to supply (i.e., $290,297) was then allocated further to the 2012 / 2013 Winter Period (93.57%) and 2013 Summer Period (6.43%) based on the actual Bad Debt experience of the respective Periods. This breakout establishes the 2013 Summer Period Bad Debt of $18,660 (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, 21.83%, or $89,856 is assigned to the Summer Period.

H. Summary Analyses

Q. How does the proposed 2013 Summer Period COG compare to the actual 2012 Summer Period COG?

A. I have prepared Schedule 9 to compare the proposed 2013 Summer Period average COG to the actual 2012 Summer Period COG. Schedule 9 indicates the projected 2013 Summer Period average COG rate of $0.5553 per therm is $0.0946 per therm higher than the actual 2012 Summer Period Total Adjusted COG rate of $0.4606 per therm. The overall change in the proposed 2013 Summer Period average rate compared to the 2012 Summer Period actual average rate is primarily due to higher demand costs, higher gas costs, and a reconciliation over-collection in the 2012 COG as compared to an under-collection in the proposed COG .

III. FINAL MATTERS

Q. Will the Company propose to revise the 2013 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 2013 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, 2013.

Q. Does this conclude your testimony?

A. Yes it does.