

**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2013 / 2014
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
CHRISTOPHER A. KAHL**

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

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

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

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

13 **Q. Please summarize your professional and educational background.**

14 A. I have worked in the natural gas industry for over twenty years. Before joining Unitil in
15 January 2011, I was employed as an Analyst with Columbia Gas of Massachusetts
16 (“Columbia”) where I had worked since 1997 in supply planning. Prior to working for
17 Columbia, I was employed as an Analyst in the Rates and Regulatory Affairs Department
18 of Algonquin Gas Transmission Company (“Algonquin”) from 1993 to 1997. Prior to
19 working for Algonquin, I was employed as a Senior Associate/Energy Consultant for

1 DRI/McGraw-Hill. I received a Bachelor of Sciences degree and a Masters of Arts
2 degree in Economics from Northeastern University.

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

5 A. Yes, I have testified before the Commission in the 2012 / 2013 Winter Period Cost of Gas
6 (“COG”) proceeding, Docket No. DG 12-272; and the 2013 Summer Period COG
7 proceeding, Docket No. DG 13-083.

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

9 A. I, Francis Wells, Manager of Gas Supply for Unitil Service, and Joseph Conneely, Senior
10 Regulatory Analyst for Unitil Service, are sharing the responsibility of supporting the
11 proposed New Hampshire Division 2013 / 2014 Winter Period COG and other proposed
12 rate adjustments in this proceeding with testimony.

13 Mr. Wells will sponsor, describe and explain the customer demand forecast and the
14 resulting forecasted gas sendout and gas costs he developed for the Maine and New
15 Hampshire Divisions. Mr. Wells will also describe the impact of the Company’s
16 Hedging Program on the 2013/ 2014 Winter Period costs.

17 Mr. Conneely is sponsoring, describing and explaining the calculation of the 2013 / 2014
18 Local Distribution Adjustment Clause (“LDAC”), and the typical customer bill impacts
19 resulting from the proposed 2013 / 2014 Winter Period COG rates.

20 I am sponsoring, describing and explaining the New Hampshire Division’s 2012 / 2013
21 Winter Period Reconciliation, the calculation of the 2013 / 2014 Winter Period COG and

1 the rates Northern proposes to charge customers from November 1, 2013 to April 30,
 2 2014.

3 **Q. Please provide a list of the attachments that you have prepared in support of your**
 4 **testimony.**

5 A. The attachments that I have prepared in support of my testimony are listed below.

6

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 2012-2013 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	2012-2013 Winter Period COG Reconciliation
Schedule 18	Supplier Balancing Charge
Schedule 19	Capacity Assignment Calculations
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 24	Short Term Debt Limit Calculation
Schedule 25	PNGTS Gas Pipeline Refund

7

1 **II. COST OF GAS FACTOR**

2 **Q. Please provide an overview of how Northern’s COG-related costs are allocated to**
3 **the New Hampshire Division rate classes.**

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

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

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

8 Step 3 – Allocate New Hampshire Division seasonal costs by rate class.

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

10 **A. Allocation of Demand-Related Costs to the Maine and New Hampshire**
11 **Divisions**

12 **Q. Please explain how the projected demand/fixed capacity-related costs, i.e. (a)**
13 **pipeline reservation and gas supply demand charges, (b) underground storage**
14 **capacity costs and (c) peaking resource capacity costs are allocated between**
15 **Northern’s Maine and New Hampshire Divisions.**

16 A. Total Northern capacity-related costs are allocated between the Maine and New
17 Hampshire Divisions by application of the Modified Proportional Responsibility
18 (“MPR”) methodology. The MPR methodology allocates fixed capacity-related gas costs
19 to the Maine and New Hampshire Divisions in a two-step process: (1) capacity-related

1 costs, by resource type¹, are allocated to calendar months by application of MPR
2 allocation factors, and (2) the capacity-related costs allocated to each month are allocated
3 to the Maine and New Hampshire Divisions based on the relative shares of Design Year
4 demand² in that month. Initially, this MPR methodology was approved orally by the
5 Commission on December 30, 2005 to be effective January 1, 2006. Subsequently, on
6 June 1, 2006, the Commission issued Order No. 24,627 in Docket No. DG 05-080
7 granting written approval of the MPR methodology.

8 As I will explain in more detail below, I used the MPR methodology to allocate total
9 Northern annual demand-related costs to the Maine and New Hampshire Divisions for the
10 2013 / 2014 Winter Season, i.e. November 2013 through April 2014, and for the 2014
11 Summer Season, i.e. May through October 2014.

12 **Q. Please give an overview of the process that you followed to allocate total Northern**
13 **demand costs for the period November 2013 through October 2014 to the Maine**
14 **and New Hampshire Divisions.**

15 A. I have prepared Schedule 21 to explain how I calculated the MPR factors and how I used
16 these factors to allocate total Northern annual demand costs for the period November
17 2013 through October 2014 (“the COG Period”) to the Maine and New Hampshire
18 Divisions. Schedule 21 is arranged in three major sections:

¹ These resources are pipeline, storage, and peaking.

² 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 2012 through April 2013, adjusted to reflect design winter effective degree day (“EDD”) conditions from November through April and normal EDD conditions from May through October.

1 (1) Total fixed capacity costs, by type of resource (pipeline, storage, and peaking),
2 are summarized in Lines 1 through 10.

3 (2) Total fixed capacity costs for each resource type are allocated to each month
4 in the COG Period according to MPR allocators that were developed specifically
5 for each resource type, as shown on Lines 13 through 56 (Schedule 21, pages 1
6 and 3), with the MPR allocators based on design year sendout volumes for each
7 resource type.

8 (3) Total fixed capacity costs allocated to each month in section 2, above, are
9 allocated to the Maine and New Hampshire Divisions according to design year
10 total firm sendout as shown in Lines 58 through 90.

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

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

16 A. Lines 3 through 6 of Schedule 21 show total Northern annual projected demand costs for
17 Pipeline, Storage, and Peaking resources; these forecasted demand costs were provided to
18 me by Mr. Wells.³ Mr. Wells also provided estimates of Capacity Release revenues and

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

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

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

11 Northern's fixed capacity costs that have been allocated to each month are summarized
12 and consolidated on Lines 50 through 56 of Schedule 21. Lines 50, 51 and 52 repeat the
13 Pipeline, Storage, and Peaking capacity costs from Lines 22, 40, and 49. Line 53 shows
14 the credit to Pipeline capacity costs that is related to the Injection Fees that have been
15 added to the Storage capacity costs. In addition: (a) 1/5th of total Capacity Release
16 revenues are allocated to each month from November through March, as shown on Line
17 54; and (b) 1/6th of total Asset Management revenues, are allocated to each month from
18 November through April, as shown on Line 55.

19 **Q. Finally, how are the total Demand Costs and the Capacity Release and Asset**
20 **Management revenues, which have been allocated to each month according to the**
21 **process that you described above, allocated to the Maine and New Hampshire**
22 **Divisions?**

1 A. Total Northern Demand Costs and Capacity Release and net Asset Management revenues
2 that are allocated to each month are then allocated to the Maine and New Hampshire
3 Divisions according to the design year total sendout for the Maine and New Hampshire
4 Divisions, which is shown in lines 61 and 62 of Schedule 21; the calculated percentages
5 are provided in lines 65 and 66. These design year sendout quantities shown on lines 61
6 and 62, are the sendout quantities required to serve Maine and New Hampshire
7 Divisions' firm sales and transportation customers that are subject to the assigned
8 capacity requirements under design conditions from May 2012 through April 2013.

9 As shown on Line 90 of Schedule 21, 47.24% of Northern's total demand costs from
10 November 2013 through October 2014 will be allocated to the New Hampshire Division
11 and the remaining 52.76%, as shown on Line 81, will be allocated to the Maine Division.

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

13 **Q. Please explain how the projected annual demand-related costs that are allocated to**
14 **the New Hampshire Division are then assigned to be recovered in the 2013 / 2014**
15 **Winter Season and the 2014 Summer Season.**

16 A. Northern allocates costs between the seasons as well as among customer classes through
17 the Simplified Market Based Allocation ("SMBA") method. I have prepared Schedule
18 1A to show detailed support for the allocation of New Hampshire Division Sales
19 Customer demand costs to months, and then to seasons utilizing the SMBA method.
20 Lines 2 through 4 of Schedule 1A summarize the Pipeline and Storage and Peaking
21 demand costs that are allocated to the New Hampshire Division, as determined in

1 Schedule 21. Lines 13 through 23 of Schedule 1A show the calculation of Net Demand
2 Costs for firm sales customers, which is Total Demand Costs allocated to the New
3 Hampshire Division less the capacity assignment revenues from New Hampshire
4 Division transportation customers. The Winter and Summer Season rates that will be
5 charged to New Hampshire Division firm sales customers from November 2013 through
6 October 2014 will recover: (1) the Net Pipeline Demand costs shown on Line 20, (2) the
7 Net Storage costs shown on Line 21 and (3) the Peaking demand costs on Line 22 of
8 Schedule 1A.⁴

9 Lines 27 through 41 of Schedule 1A show the calculation of pipeline demand costs for
10 sales customers, separated into (1) Base Use demand costs and (2) Remaining Use
11 demand costs.⁵ The Base Use that is shown on Line 32 of Schedule 1A is the average
12 projected daily use in July and August 2014⁶ for all firm sales classes; the Base Use
13 Pipeline Demand cost that is shown on Line 40 of Schedule 1A is calculated by
14 multiplying Base Use times the weighted average annual cost of pipeline capacity, as
15 shown on Line 36 of Schedule 1A. Line 41 shows the Remaining Use Net Pipeline
16 Demand costs for sales customers, which is the difference between total net pipeline
17 demand costs and Base Use pipeline demand costs.

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).

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.

1 Lines 45 through 50 of Schedule 1A show the calculation of the Proportional
2 Responsibility (“PR”) allocator that is used to allocate (a) Remaining Use Net Pipeline
3 Demand costs; and (b) Storage and Peaking costs related to Firm Sales customers for
4 twelve months, i.e., November 2013 through October 2014. Lines 52 through 57 show
5 the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset
6 Management revenues; and (d) Interruptible margins and Delivery-to-Sales revenues to
7 the Winter Season months, November 2013 through April 2014. These PR factors are
8 summarized by type of capacity cost in lines 61 through 65. Line 61 of Schedule 1A
9 shows that $1/12^{\text{th}}$ of the net annual Base Use pipeline demand costs is allocated to each
10 month and Lines 68 through 85 show the detailed allocation to months of all components
11 that are included in the Total Net Demand Costs, based on the “All Months” and “Peak
12 Months Only” allocation factors.

13 The total direct demand costs to be recovered in the 2013 / 2014 Winter Season COG
14 rates, \$9,610,249 is shown in Schedule 1A, on Line 80, Winter column.

15 Further, as shown on Page 6 of Schedule 1A, the New Hampshire Division’s portion of
16 Northern’s share of litigation costs incurred by the Portland Natural Gas Transmission
17 System (“PNGTS”) Shippers Group (“PSG”) in the PNGTS rate case, RP10-729, from
18 August 2012 through July 2013 is \$22,988. For the purpose of incorporating this PNGTS
19 Litigation Expense into the COG rates, which is discussed in Mr. Well’s testimony, I
20 have reflected these costs as an offset to expected Capacity Release and Asset
21 Management revenues which is shown on Line 76 in Schedule 1A.

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

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

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

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

19 I have prepared Schedule 10A to show the allocation of Winter Season New Hampshire
20 Division Net Demand costs to each firm sales rate class, based on (a) the New Hampshire
21 Net Demand costs that are allocated to each Winter Season month as shown in Schedule
22 1A, Lines 67 through 80, and (b) the Rate Class allocators as shown Schedule 10B, Lines

1 49 to 80. The Base Sendout allocators, which are used to allocate base demand costs to
2 firm sales rate classes, are shown on Lines 3 through 22 of Schedule 10A and the
3 Remaining Design Day allocators, which are used to allocate all other demand-related
4 costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

5 The following table shows the location in Schedule 10A of the Net Demand-related costs
6 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

7
8 **D. Allocation of Variable Costs**

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

11 A. Variable costs include commodity costs and variable pipeline and storage costs⁷ for firm
12 sales. Mr. Wells prepared a forecast of Northern's variable gas costs by month, which is
13 provided in Schedule 6A. These variable gas costs have been allocated between the
14 Maine and New Hampshire Divisions based on each Division's percentage of monthly

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

1 firm normal sendout. I have prepared Schedule 22 to show the allocation of the 2013 /
2 2014 Winter Season variable gas costs between the Maine and New Hampshire
3 Divisions.

4 **Q. Please explain Schedule 22.**

5 A. Lines 1 through 9 of Schedule 22 show the projected sendout volumes, by month and by
6 resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected
7 variable costs by month and by type of gas supply resource that are shown on Lines 11,
8 and Lines 18 through 20 of Schedule 22. The pipeline commodity costs shown on Lines
9 11 and 18 are based on projected NYMEX prices as of September 5, 2013. Lines 23
10 through 30 show the estimated gains and losses based on the Company's time-triggered
11 hedging program, and the projected NYMEX prices. The variable gas costs and hedging
12 gains and losses for firm sales service that are summarized on Lines 30 and 40 are
13 allocated to the Maine and New Hampshire Divisions based on projected monthly firm
14 sales sendout in each division; the allocators are shown on Lines 54, 55, 59 and 60.
15 Gains and losses based on the price-triggered hedging program are shown on Lines 31
16 through 37; these price-triggered hedging gains and losses are directly assigned to the
17 New Hampshire Division. Schedule 22 also shows the allocation of (a) Commodity costs
18 (Maine Division: Lines 65, 67, 68, and 69; New Hampshire Division: Lines 74, 76, 77,
19 and 78); and (b) hedging gains and losses (Lines 66 and 75) to the Maine and New
20 Hampshire Divisions respectively. Finally, Schedule 22 shows the inventory finance
21 costs for underground storage and LNG resources (Lines 99 to 101); the allocation of
22 these costs to the Maine and New Hampshire Divisions (Lines 104 to 106), and the

1 allocation of New Hampshire Division's allocated share of annual inventory finance costs
2 to the Winter Season, using the firm sales remaining sendout allocators (Lines 115 to
3 117).

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

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

9 A. The inventory finance charges that are shown on Lines 71, 80, and 89 of Schedule 22 are
10 derived from the inventory finance costs that are shown on Lines 99 and 100 of Schedule
11 22⁸. These inventory finance costs were calculated based on forecasted inventory activity
12 calculations which are shown in Schedule 14.

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

15 A. Under its current Asset Management Arrangement, which runs through March 2014, the
16 Company does not incur inventory finance costs on the Washington 10 inventories, and
17 the Company anticipates contracting for similar terms beginning April 1, 2014. For this

⁸ Schedule 22 shows November through April commodity costs; inventory finance costs for May through October are included in the total annual costs (i.e. November through October) shown in Column N of Lines 99 through 101. Total 2013/2014 inventory finance costs allocated to New Hampshire (Line 105) are recovered in the Winter Season, as shown on Line 80 of Schedule 22.

1 reason, no inventory finance costs for Washington 10 Storage were calculated or included
2 in rates.

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

5 A. I have prepared Schedule 10C to show the allocation of New Hampshire Division
6 variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base
7 Sendout allocators by rate class. Lines 22 to 49 show the allocation of the monthly New
8 Hampshire Division Base Commodity and Base Hedging costs⁹ to each rate class. Lines
9 50 to 70 show the calculation of the Remaining Sendout allocators by rate class. Lines
10 71 to 98 show the allocation of the monthly New Hampshire Division Remaining
11 Commodity and Remaining Hedging costs¹⁰ to each rate class. A summary of all
12 commodity costs allocated to the New Hampshire Division's firm sales classes is shown
13 on Lines 99 to 140.

14 **E. Refunds**

15 **Q. Are there any refunds included in this filing?**

16 A. Yes, Northern is flowing through the refund received by Portland Natural Gas
17 Transmission System ("PNGTS"). The specifics of the refund are provided in Mr. Wells'
18 testimony. This refund is being credited to customers over the 12-month period

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

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

1 November 2013 through October 2014. For the Winter Season, Northern's New
2 Hampshire Division sales customers are credited (\$449,049) as shown on Line 27 of the
3 Summary Schedule. The calculations supporting the refund are provided in Schedule 25.

4 **F. 2012 – 2013 Winter Season Reconciliation**

5 **Q. Please explain the 2012 / 2013 Winter Season over and under-collections.**

6 A. The 2012 / 2013 Winter Season COG Adjustment Reconciliation ("Reconciliation") was
7 filed with the Commission on July 23, 2013. The Reconciliation provides a detailed
8 explanation of the Winter Season's over-collection of (\$2,128,249) as of April 30, 2013,
9 and is included in this filing as Schedule 15.

10 G. Miscellaneous Charges and Credits

11 **Q. Are you projecting that Northern will receive any Re-Entry Fee Credits from**
12 **transportation customers returning to sales service during the 2013 / 2014 Winter**
13 **Season?**

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

15 **Q. How were Northern's Working Capital Costs derived?**

16 The Working Capital Costs were based on the Working Capital Allowance of 0.0824%
17 which was approved in Northern's most recent base rate proceeding, Docket No. DG 11-
18 069. This percentage, when multiplied by the forecasted Peak Period Direct Cost of Gas
19 yields a Working Capital Cost of \$21,081. This amount is included in the Summary
20 Schedule at line 34.

1 **Q. How did Northern develop its current projected Bad Debt expense for inclusion in**
2 **the 2013 / 2014 Winter Season COG?**

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

5 As shown on Line 3 of Schedule 3B, for the 12-months ended July 31, 2013, actual write-
6 offs for Northern's New Hampshire Division were \$360,081. For 2013 / 2014, Northern
7 projects annual Bad Debt expense to be \$500,000 (Line 17).

8 The annual Bad Debt forecast was then allocated to supply (57%) and distribution (43%)
9 based on the actual Bad Debt experience of these components over the 12-months ended
10 July 2013. This is shown on Lines 7 and 5, respectively, of Schedule 3B. The annual
11 Bad Debt forecast for supply (\$206,009), as shown on Line 6, was then allocated further
12 to the 2013 / 2014 Winter Season (92%) and 2013 Summer Season (8%) based on the
13 actual Bad Debt experience of the respective seasons, as shown on Lines 11 and 13. This
14 breakout establishes the Winter Season Bad Debt of \$263,169 (Line 19). I have included
15 this expense at line 41 in the summary schedule.

16 **Q. Please explain the costs related to the Company's local production and storage**
17 **facilities, and Other Administrative and General ("A&G") expenses that are**
18 **included in the Winter Season COG.**

19 A. Northern's local production and storage costs were set at \$307,762 in the company's last
20 base rate case proceeding, Docket No. DG 11-069, and are recovered solely in the Winter
21 Season. Also in the last base rate case proceeding, A&G expenses were set at \$411,600.

1 Of this amount, \$333,160 is recovered from sales customers in the Winter Season. These
2 amounts are included in the Summary Schedule on lines 45 and 47.

3 **H. Cost of Gas Factor**

4 **Q. Please explain the calculation of the proposed New Hampshire Division COG**
5 **factors for the 2013 / 2014 Winter Season.**

6 A. The Summary Schedule, which is similar to the Company's COG tariff Pages 38 and 39,
7 has been prepared to explain the calculation of the proposed 2013 / 2014 Winter COG
8 factors. The text descriptions in Column D, pages 3 & 4: (1) explain the calculations on
9 this tariff page; and (2) provide references to other schedules for the sources of the data
10 that appear on COG tariff Pages 38 and 39. This Summary Schedule shows the
11 calculation of the 2013 / 2014 Winter Season COG for each of Northern's three COG
12 Rate Groups: (1) Residential classes R-1 and R-2, (2) C&I Low Winter use classes G-50,
13 G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42.

14 As shown on the Summary Schedule for the 2013 / 2014 Winter Season, the projected
15 Average Cost of Gas is \$0.8567 per therm (Line 73), which is the sum of the average
16 Total Direct Cost of Gas, \$0.9177 per therm (Line 66) and the average Indirect Cost of
17 Gas, (\$0.0610) per therm (Line 70).

18 **Q. What are the major components of the 2013 / 2014 Winter Season Anticipated**
19 **Direct Cost of Gas?**

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

1

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	\$2,591,047	3
2	Purchased Gas Supply Costs	\$11,116,950	4
3	Storage and Peaking Capacity Costs	\$11,679,992	7
4	Storage and Peaking Commodity Costs	\$4,717,787	8
5	Hedging (Gain) / Loss	\$144,792	10
6	Inventory Financing	\$5,527	14
7	Capacity Release and AMA revenue net of PNGTS Litigation Costs	(\$4,660,791)	16
8	Total Anticipated Direct Cost of gas	\$25,595,305	20

2

3 **Q. What are the major components of the 2013 / 2014 Winter Season Anticipated**
 4 **Indirect Cost of Gas?**

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

7

			Summary Schedule, Line:
1	Prior Period (Over) / Under-collection	\$(2,128,249)	24
2	Interest	\$23,596	26
3	Refunds	\$(449,048)	27
4	Interruptible Margins	\$0	28
5	Working Capital Allowance	\$19,229	38
6	Bad Debt Allowance	\$191,220	43
7	Local Production and Storage	\$307,762	45
8	Miscellaneous Overhead	\$333,160	47
9	Total Anticipated Indirect Cost of Gas	\$(1,702,330)	49

8

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

2 The total Working Capital allowance, \$19,229 is shown on Line 38 of the Summary
3 Schedule is the sum of the current period working capital allowance, \$21,081 (Line 34),
4 plus the prior Winter Season Working Capital reconciliation balance, (\$1,852) (Line 36).

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

6 A. The Bad Debt allowance, \$191,220 (Line 43), is the sum of the current period bad debt
7 allowance, \$263,169 (Line 41), plus the prior Winter Season Bad Debt reconciliation
8 balance, \$(71,949) (Line 42).

9 **I. Summary Analyses**

10 **Q. How does the proposed 2013 / 2014 Winter Season COG rate compare to the actual**
11 **2012 / 2013 Winter Season COG?**

12 A. I have prepared Schedule 9 to compare the proposed 2013 / 2014 Winter Season average
13 COG to the actual 2012 / 2013 Winter Season COG. Schedule 9 indicates the projected
14 2013 / 2014 Winter Season average COG rate, \$0.8567 per therm, is \$0.1338 per therm
15 higher than the actual 2012 / 2013 Winter Season Total Adjusted COG, \$0.7229 per
16 therm. This \$0.1338 per therm increase is primarily due to the large prior period
17 negative/credit balance and the off-system sales revenues that occurred in the 2012 / 2013
18 Winter Season.

1 **III. ADDITIONAL SCHEDULES AND SUPPLIER BALANCING CHARGE**

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

4 A. Yes, Schedules 3, 19, 23 and 24. Schedule 3 determines Northern's projected
5 over/under-collections, balances, and interest calculations. Schedule 19 calculates the
6 capacity assignment percentages for capacity eligible transportation customers. Schedule
7 23 provides additional detail to the proposed tariff sheets. Lastly, Schedule 24
8 determines Northern's short term debt limit calculation for the period November 2013
9 through October 2014.

10 **Q. Have you updated the Supplier Balancing Charge for the period November 1, 2013**
11 **through October 31, 2014?**

12 A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1,
13 2013, \$0.77 per MMBtu, is the same as the currently effective Supplier Balancing
14 Charge. I have prepared Schedule 18 to support the Supplier Balancing Charge.

15 **IV. FINAL MATTERS**

16 **Q. Will the Company propose to revise the 2013 / 2014 Winter Season COG if it**
17 **receives any new or updated information on gas supplier or transportation rates?**

18 A. Yes. The Company plans to file a revised calculation of its 2013 / 2014 Winter Season
19 COG to reflect updated gas and pipeline transportation cost projections as well as any
20 other cost information a few weeks prior to the effective date of November 1, 2013.

1 **Q. Does this conclude your testimony?**

2 **A. Yes it does.**