NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2018 / OCTOBER 2019 ANNUAL PERIOD
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-five 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 have testified before the Commission in the 2018 / 2019 Annual Cost of Gas ("COG") proceeding, Docket No. DG 18-144 and the 2017 / 2018 Annual COG proceeding, Docket No. DG 16-819. I have testified in numerous other Cost of Gas proceedings as well.

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

A. This proceeding reflects the annual reconciliation and COG filing and will present both 2018 / 2019 Winter Season and 2019 Summer Season COG rates. I, Francis Wells, Manager of Gas Supply for Unitil Service, and Joseph Conneely, Senior Regulatory Analyst for Unitil Service are sharing the responsibility of supporting the proposed New Hampshire Division 2018 / 2019 Annual COG and other proposed rate adjustments in this proceeding with testimony.

Mr. Wells' testimony is with regard to the customer demand forecast and the resulting forecasted gas sendout and gas costs he developed for the Maine and New Hampshire Divisions. Mr. Wells also describes recent changes to Northen's supply portfolio.

Mr. Conneely's testimony concerns the calculation of the 2018 / 2019 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2018 / 2019 Winter Season and 2019 Summer Season COG rates.

My testimony presents and explains the New Hampshire Division's 2017 / 2018 Annual Reconciliation, the calculation of the 2018 / 2019 annual COG and the rates Northern proposes to charge customers for the November 1, 2018 to April 30, 2019 Winter Season, and for the May 1, 2019 to October 31, 2019 Summer Season.

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

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

Summary Schedule	Cost Overview & Calculation of the COG Rates
Schedule 1A	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Schedule 1B	New Hampshire Division Commodity Cost Analysis
Schedule 3	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Schedule 4	Bad Debt (Actual/Forecast)
Schedule 7	Re-entry Rate & Conversion Rate Revenues and Volumes
Schedule 9	Rate Comparison to 2017 - 2018 Winter & 2018 Summer
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	2017 - 2018 Annual Reconciliation
Schedule 18	Supplier Balancing Charge
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

II. COST OF GAS FACTOR

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

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

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

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

Step 3 – Allocate New Hampshire Division seasonal costs to each rate class.

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

Q. Has the Company made any changes to its supply purchases that impact cost allocation?

A. Yes. As of November 1, 2017, Northern is no longer purchasing off-system peaking supplies for capacity-assigned Delivery Service customer loads in both the Maine and New Hampshire Divisions. I will explain how this impacts cost allocation below.

A. Allocation of Northern's Demand-Related Costs to the Maine and New Hampshire Divisions

Q. Please explain how Northern's projected fixed 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. Northern's total demand costs are allocated to the Maine and New Hampshire Divisions by application of the Modified Proportional Responsibility ("MPR") methodology. The MPR methodology allocates fixed gas costs to the Maine and New Hampshire Divisions in a two-step process: (1) costs, by resource type[1], are allocated to months by application of MPR allocation factors; and (2) the 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 pursuant to settlements in Docket Nos. 2005-087 and 2005-273.

As I will explain in more detail below, I used the MPR methodology to allocate Northern's projected total annual demand costs to the Maine and New Hampshire Divisions for the 2018 / 2019 Winter Season (November 2018 through April 2019) and for the 2019 Summer Season (May 2019 through October 2019).

Q. Please give an overview of the process you followed to allocate Northern's projected total demand costs for the 12-month period November 2018 through October 2019 to the Maine and New Hampshire Divisions.

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1 Pipeline, storage and peaking.

2 For the MPR allocation process, Design Year demand is calculated as the actual demand to Maine and New Hampshire Division's firm sales and assigned capacity / non-grandfathered transportation customers for the period May 2017 through April 2018, adjusted to reflect design weather conditions from November through April and normal weather conditions from May through October.

A. I have prepared Schedule 21 to explain how I calculated the MPR factors and how I used these factors to allocate Northern's total demand costs for November 2018 through October 2019 ("COG Period") to the Maine and New Hampshire Divisions. In this attachment, I distinguish between two types of demand costs; Capacity-related and Off-system Peaking demand costs. Capacity-related demand costs reflect the resource costs of pipeline, storage and on-system peaking supplies for both Sales Service and capacity assigned Delivery Service customers. Off-system Peaking demand costs reflect the costs associated with Off-system Peaking resources for only Sales Service customers.

Schedule 21 is arranged in the following six major sections;

(1) Total Capacity-related demand costs, by type of resource (pipeline, storage, on-system peaking, and other capacity related costs and credits), are summarized in Lines 1 through 10.

(2) Capacity-related demand 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 16 through 52, where the MPR allocators are based on design year sendout volumes for each resource type.

(3) Capacity-related demand costs that are allocated to each month in Section 2 are allocated to the Maine and New Hampshire Divisions according to design year total firm sendout as shown in Lines 53 through 96.

4) Off-system Peaking demand costs, shown on Line 97, are allocated to each month in the COG Period according to MPR allocators that were developed based on the dispatch of Sales Service customers as shown in Lines 99 through 106.

5) Off-system Peaking demand costs that are allocated to each month in Section 4 are allocated to the Maine and New Hampshire Divisions according to design year total Sales Service sendout as shown in Lines 108 through 123.

6) Total Demand costs for each division are then calculated by taking a weighted average of Capacity- related demand costs and Off-system Peaking demand costs as shown in Lines 124 through 137. From these calculations, the PR allocators are determined. As shown, for November 2018 to October 2019, the PR allocators are 55.89% for the Company's Maine Division and 44.11% for the New Hampshire Division.

I note the second column of Pages 2, 4 and 6 of Schedule 21 describes the sources of data and explains the calculations included in Schedule 21, on Pages 1, 3 and 5. Similar explanations are included in other schedules referenced in my testimony.

Q. Why are Off-system Peaking demand costs listed in steps 4 through 6 allocated separately from all other demands costs?

A. As I previously stated, beginning on November 1, 2017, the Company no longer purchases Off-system Peaking supplies for capacity-assigned Delivery Service customers in either its Maine or New Hampshire Divisions[3]. Accordingly, these costs should not be included in the allocation of Capacity-related demand costs because the associated dispatch of these resources includes capacity-assigned (i.e. Sales Service plus capacity-assigned Delivery Service) load. A capacity resource, like the Off-system Peaking Supplies, that reflects only the cost associated with Sales Service customers should be allocated between divisions based on the dispatch of Sales Service load only.

Q. Please explain how you allocated Northern's forecasted total Capacity-related demand costs to the months in the COG Period.

A. Lines 3 through 5 of Schedule 21 show Northern's total projected demand costs for Pipeline, Storage, and On-system Peaking resources[4]. Also included are estimates of Northern's Capacity Release and Asset Management revenues, which I have summarized in Lines 8 and 9 of Schedule 21

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and On-system Peaking demand costs to each month are shown on Schedule 21, Lines 20 through 25, Lines 36 through 43 and Lines 47 through 52, respectively. In addition, Lines 29 through 32 show the calculation of the Storage Injection Fees, by month. Storage Injection Fees represent capacity costs that comprise the portion of Northern's pipeline capacity that is used to transport gas to and from the

[3] Northern ceased purchasing Off-system Peaking supplies for capacity assignment customers in the New Hampshire Division effective November 1, 2016.

[4] The forecast of demand costs is provided in Schedule 5A.

underground storage fields. If the Company expects to incur such fees, they fees are added to the Storage demand costs, as shown on Line 42, and subtracted from the Pipeline demand costs, as shown on Line 57. However, as indicated, for the 2018/ 2019 Winter Season, storage injection fees are zero. This is because Northern is purchasing storage gas directly at the underground storage facility thereby eliminating the need for transportation to the facility and the associated transfer of costs.

Northern's fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 54 through 60. Lines 54, 55 and 56 repeat the Pipeline, Storage, and On-system Peaking capacity costs from Lines 25, 43, and 52. Line 57 shows the credit to Pipeline capacity costs that is related to the Storage Injection Fees that have been added to the Storage capacity costs[5]. In addition, 1/5 of total Capacity Release revenues are allocated evenly to each month from November through March, as shown on Line 58, and 1/6 of total Asset Management revenues are allocated evenly to each month from November through April, as shown on Line 59.

Q. How are the total Capacity-related 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?

[5] As indicated, for the 2018 / 2019 Winter Season, the credit is zero due to purchases being made directly at the storage facility.

A. Northern's Total Capacity-related Demand Costs[6] and Capacity Release and Asset Management revenues allocated to each month are then allocated to the Maine and New Hampshire Divisions according to the design year total firm sendout for both divisions, which is shown in Lines 65 and 66 of Schedule 21; the calculated percentages are provided in Lines 70 and 71. In accordance with Commission-approved settlements[7], the design-year firm sendout quantities for the COG Period as shown on Lines 65 and 66 are the sendout quantities required to serve the Maine and New Hampshire Divisions' firm sales and transportation customers that are subject to the assigned-capacity requirements under design winter conditions from May 2017 to April 2018.

Q. Is the same process used for allocating Capacity-related demand costs also used for Off-system Peaking demand costs?

A. Yes. Lines 101 through 106 of Schedule 21 use the same process for allocating resource costs to each month as that used in Lines 47 through 52. Also, Lines 109 through 123 use the same process for applying monthly costs to divisional sendout as used in Lines 62 through 77. As shown in Lines 121 and 122, Off-system Peaking demand costs are allocated to each division based on the dispatch of Sales Service customers only[8].

Q. Finally, how are the combined PR Allocators for both Capacity-related and Sales Service demands calculated?

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[6] Costs reflect pipeline, storage and on-system peaking resources.
[7] These settlements were approved in Docket Nos. 2005-87 and 2005-273.
[8] The major difference from prior cost of gas proceedings is not in the process but in the assignment to each division.

A. The combined PR allocators are based on the weighted average of the Capacity-related and Off-System Peaking PR Allocators. Lines 125 and 130 of Schedule 21 show the Capacity-related PR allocators while Lines 126 and 131 show the corresponding values for Off-system peaking PR allocators. Lines 127 and 132 show the combined PR Allocators, 55.89% for Maine and 44.11% for New Hampshire, used to assign costs between divisions.

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 2018 / 2019 Winter Season and the 2019 Summer Season.

A. Northern allocates costs between the seasons as well as among customer classes through the Simplified Market Based Allocation ("SMBA") method. 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 utilizing the SMBA method.

Lines 2 through 4 of Schedule 1A summarize the Pipeline and Storage and Peaking demand costs that are allocated to the New Hampshire Division, as determined in Schedule 21. Lines 12 through 22 of Schedule 1A show the calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs allocated to the New Hampshire Division less the capacity assignment revenues from New Hampshire Division transportation customers. The Winter and Summer Season rates that will be charged to New Hampshire Division firm sales customers from November 2018 through October 2019 will recover: (1) the Net Pipeline Demand costs shown on Line 19; (2) the

Net Storage costs shown on Line 20; and (3) the On-system Peaking demand costs shown on Line 21 of Schedule 1A.[9]

Lines 26 through 40 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.[10] The Base Use that is shown on Line 31 of Schedule 1A is the average projected daily use in July and August 2019[11] for all firm sales classes. The Base Use Pipeline Demand cost that is shown on Line 39 of Schedule 1A is calculated by multiplying Base Use, shown on Line 31, times the weighted average annual cost of pipeline capacity, as shown on Line 35 of Schedule 1A. Line 40 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 44 through 49 of Schedule 1A show the calculation of the Proportional Responsibility ("PR") allocator that is used to allocate (a) Remaining Use Net Pipeline Demand costs and (b) Storage and On-system Peaking costs related to Firm Sales customers for twelve months, November 2018 through October 2019. Lines 51 through 55 show the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset Management revenues, (d) Interruptible margins and Re-entry Rate and Conversion Rate revenues and (e) Off-system Peaking Supplies to the Winter Season months,

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[9] These direct demand costs are adjusted by Capacity Release and Asset Management revenues (Line 76); Interruptible margins (Line 77); and Re-Entry Rate and Conversion Rate Credits (Line 78).

[10] 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.

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

November 2018 through April 2019. These PR factors are summarized by type of capacity cost at lines 60 through 65. Line 60 of Schedule 1A shows that 1/12th of the net annual Base Use pipeline demand costs is allocated to each month, and Lines 69 through 79 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.

As shown on Line 79 of Schedule 1A, $11,373,963 of direct demand costs are allocated to the 2018 / 2019 Winter Season, and $756,079 is allocated to the 2019 Summer Season.

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

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter and Summer Seasons are 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 pro rata share of total forecasted firm sendout to sales customers under normal weather conditions in that month. The remaining demand-related costs for each month are allocated to each sales service rate class based on that class's pro rata share of total forecasted firm sales design day, temperature-sensitive demand.

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

I have prepared Schedule 10A to show the allocation of Winter and Summer Season New Hampshire Division Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Winter Season and Summer Season month as shown in Schedule 1A, Lines 69 through 79, 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. 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
Off-system Peaking Demand	Lines 86 through 102
Capacity Release & Asset Mgmt. Revenues	Lines 105 through 121
Interruptible, Re-entry & Conversion Revenues	Lines 123 through 139
Total Non-Base Capacity Costs	Lines 141 through 155
Total Capacity Costs	Lines 157 through 175

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[12] 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 2018 / 2019 Winter and Summer Season variable gas costs between the Maine and New Hampshire Divisions.

Q. Please explain Schedule 22.

A. Lines 1 through 10 of Schedule 22 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 12, and Lines 19 through 21 of Schedule 22. This Schedule also shows projected Off-system Sales revenues on Line 22. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of August 29, 2018. The variable gas costs for firm sales service summarized on Lines 24 and 36, are allocated to the Maine and

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

New Hampshire Divisions based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 40, 41, 45 and 46. Schedule 22 also shows the allocation of Commodity costs to the two Divisions, (Maine Division: Lines 51 through 57; New Hampshire Division: Lines 59 through 65). Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 82 to 84), the allocation of these costs to the Maine and New Hampshire Divisions (Lines 87 to 89), and the allocation of New Hampshire Division's allocated share of annual inventory finance costs to the Winter Season, using the firm sales remaining sendout allocators (Lines 98 to 100).

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. Are there any hedging costs included in the Commodity Cost calculations?

A. No. In Northern's Maine Division, 2018 Summer Season cost of gas filing, Docket No. 2018-041, the Commission approved[13] the Company's request to terminate its hedging program. In addition, all previous hedges have expired; therefore no additional hedging costs will be incurred by Northern.

Q. Please explain how you calculated the inventory finance costs for underground storage and LNG resources that are included in Schedule 22.

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[13] Order dated May 5, 2018.

A. The allocation of inventory finance charges to the Company's Maine and New Hampshire Divisions are shown on Lines 87 and 88 of Schedule 22. These inventory finance costs, as shown on Lines 82 and 83 were calculated based on forecasted inventory activity calculations which are shown in Schedule 14.

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 35 show the allocation of the monthly New Hampshire Division Base Commodity costs[14] to each rate class. Lines 37 to 56 show the calculation of the Remaining Sendout allocators by rate class. Lines 57 to 70 show the allocation of the monthly New Hampshire Division Remaining Commodity costs[15] to each rate class. A summary of all commodity costs allocated to the New Hampshire Division's firm sales classes is shown on Lines 71 to 84.

E. <u>Refunds</u>

Q. Are there any refunds included in this filing?

A. No. Previously, Northern had been crediting back the Portland Natural Gas Transmission System rate case refund to Sales Service customers over a three year period. However,

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[14] New Hampshire Division Winter Season Base Commodity costs by month are shown in Schedule 1B Lines 34.

[15] New Hampshire Division Winter Season Remaining Commodity costs and Hedging costs by month are shown in Schedule 1B Lines 35.

the final installment was credited back in the 2017 / 2018 Winter COG Season. The remaining balance, a $51,125 credit, due to variances between estimated and actual payments to retail choice customers as well as variances between projected and actual interest rates, has been transferred to the Demand and Commodity account and will be recovered in this COG proceeding within the annual reconciliation.

F. <u>2017 / 2018 Annual Reconciliation</u>

Q. Please explain the 2017 / 2018 Annual COG Reconciliation.

A. The 2017 / 2018 Annual COG Reconciliation is provided as Schedule 15. As Page 1 of this Schedule indicates, the projected October 31, 2017 annual ending balance is an under-collection of $680,009.

I have also modified Schedule 1 of the Annual Reconciliation to show how the ending balance will be allocated between the upcoming 2018 / 2019 Winter and 2019 Summer Seasons. As illustrated, the allocation between seasons will be based on the portion of projected sales that occur in each season. Similar allocations are provided for Attachment A (Working Capital) and Attachment B (Bad Debt) of this Annual Reconciliation.

G. <u>Miscellaneous Charges and Credits</u>

Q. Is Northern proposing any credits to the COG for transportation customers returning to Sales Service?

A. Yes. In last year's COG filing, Docket No. 2017-144, the Commission approved Northern's request to replace its Firm Sales Service Re-entry Fee with two separate fees; the Re-entry Rate and the Conversion Rate. The Re-entry rate applies to capacity non-exempt Delivery Service customers whereas the Conversion Rate applies to capacity exempt Delivery Service customers. Northern is projecting a combined total of $10,000 in revenues associated with the Re-entry Rate and Conversion Rate. This amount is included in the Summary Schedule at Line 14.

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

The Working Capital Costs were based on a formula approved in Northern's 2017 base rate proceeding, Docket No. DG 17-070. This formula derives the working capital percentage by dividing the supply related net lag of 10.02 days by 365 days and then multiplying the result by the prime interest rate. Based on the current prime rate of 5.00%, the Working Capital Percentage is 0.2742%. This percentage, when multiplied by the each season's forecasted Direct Cost of Gas, yields a 2018 / 2019 Winter Season Working Capital Cost of $74,383 and a 2019 Summer Season Working Capital Cost of $7,572. These amounts are included in the Summary Schedule at lines 29 and 138.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2018 / 2019 Winter Season and 2018 Summer Season COGs?

A. To develop its bad debt projections, Northern forecasts 12 months of customer write-offs for both supply and distribution service. This forecast is based on actual experience and any recent unexpected increases or decreases in the number of customer write-offs.

As shown on Line 3 of Schedule 4, for the 12-months ended July 31, 2018, actual write-offs for Northern's New Hampshire Division were approximately $452,000. For the twelve months ended December 31, 2019, Northern projects annual Bad Debt expense to be $450,000 (Line 14).

The projected annual Bad Debt expense was then allocated to supply (42%) and distribution (58%) services based on the actual Bad Debt experience of these components over the 12-months ended July 31, 2018. This is shown on Lines 7 and 5, respectively, of Schedule 4. The annual Bad Debt expense forecast allocated to supply, $188,646 as shown on Line 15, was then allocated further to the 2018 / 2019 Winter Season (94%) and 2019 Summer Season (6%) based on the allocation of demand costs between the Winter and Summer Seasons. This breakout establishes the Winter Season Bad Debt of $177,230 (Line 16) and a Summer Season Bad Debt expense of $11,416, (Line 17). I have included these expenses at lines 36 and 144 in the Summary Schedule.

Q. What steps does the Company take to reduce its Bad Debt Expense?

A. In addition to proactively providing customers with tools and information to manage their accounts and avoid arrearages, the Company has a multi-step program in place for maximizing the collection of receivables from customers with delinquent balances and reducing bad debt. The goal of this program is to enable customers with delinquent balances the ability to avoid disconnection and continue to receive gas service while meeting their payment obligations. In this program, the Company employs a variety of measures to maximize collections of receivables and reduce bad debt. Customer specific measures include the following:

- Invoices are mailed out monthly so the customer is aware of any past due balance;
- All accounts with a delinquent balance that meet the criteria established by New Hampshire Public Utilities Commission ("PUC") rules, and are not protected from disconnection pursuant to said rules, receive a disconnect notice requiring that the customer pay the delinquent balance before the scheduled disconnection date or call the Company to discuss a payment plan;
- If the past due location is a master meter (e.g., a single meter that serves a multi-unit property), the property is posted to advise tenants of potential disconnection of service.

The Company also communicates regularly with its customers via bill messages, bill inserts, newsletters, and its website, and shares tools and information that enable customers to manage their accounts, including a budgeting tool, payment plan options, and information regarding the discount program and financial assistance.

In addition to the steps outlined above, Northern performs a monthly review of commercial customer accounts to identify commercial customers that have received four or more disconnect notices in a twelve month period. Unitil sends a deposit warning letter to such customers notifying them that if their outstanding balance is not paid within 30 days, the Company will assess a deposit to their account.

When a customer calls the Company in response to a disconnect notice or to otherwise address a delinquency, we review several options with the customer to resolve the delinquency, including full payment and sufficient partial payment coupled with a payment plan for the balance. Monthly letters are mailed to customers on any standard payment plan to remind them of payment amounts and due dates to encourage timely payments. The Company may also refer customers to "211" for contact information regarding discounted rates, financial assistance and energy efficiency programs.

When Northern learns that a customer is protected from a service disconnection per PUC rules, the Company codes customers' accounts accordingly to prevent disconnect notices, but continues to work with the customers to set reasonable payment arrangements. Such efforts include monthly outbound calls to customers to discuss payment and plans and bi-monthly letters to customers to discuss payment and plans.

When a customer remains delinquent two days before the scheduled disconnection date, the Company will make an outbound call to attempt to secure payment and discuss the customer's options. If an adequate payment is not received, an acceptable payment plan is not established, or the Company does not determine that the customer is protected from disconnection, the Company issues a disconnection work order to shut off the customer's service.[16]

If, after an account is shut off for non-payment, the customer calls and makes a full or otherwise sufficient payment, the Company will reinstate service to the customer upon payment of a deposit, and establish a payment plan for any remaining balance. If the customer does not respond, the Company closes the account and mails a final bill to the customer. If the customer does not make payment on the final bill, the Company mails an additional reminder notice and makes an outbound call to the customer to request payment or establish a reasonable payment plan. It is only after the Company receives no response to its proactive steps that the customer account is referred to a Collection Agency and the receivables are classified as bad debt.

[16] If a disconnection work order is issued during the Winter Moratorium, the Company makes contact with an adult resident of the property prior to disconnecting service.

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

A. Northern's local production and storage costs were set at $476,106 in the Company's most recent base rate case proceeding, Docket No. DG 17-070, and are recovered solely in the Winter Season. Also in the last base rate case proceeding, A&G expenses were set at $580,455. Of this amount, $471,052 is recovered from sales customers in the Winter Season and $109,403 is recovered in the Summer Season. These amounts are included in the Summary Schedule on lines 40, 42 and 150.

H. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2018 / 2019 Winter Season and the 2019 Summer Season.

A. The Summary Schedule, which is similar to the Company's COG tariff Pages 40 through 43, has been prepared to explain the calculation of the proposed 2018 / 2019 Winter and 2019 Summer COG factors. The text descriptions in Column D, pages 2, 4, 6, 8 and 10 explain the calculations on this tariff page and provide references to other schedules for the sources of the data that appear on referenced COG tariff pages. This Summary Schedule shows the calculation of the Winter and Summer Season COGs for each of Northern's three COG Rate Groups: (1) Residential classes R-5, R-6 and R-10; (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 Page 3 of the Summary Schedule, the 2018 / 2019 Winter Season projected Average Cost of Gas is $0.8271 per therm (Line 66), which is the sum of the average Total Direct Cost of Gas, $0.7778 per therm (Line 59) and the average Indirect Cost of Gas, $0.0493 per therm (Line 63). As shown of Page 7 of the Summary Schedule, the 2019 Summer Season, the projected Average Cost of Gas is $0.3670 per therm (Line 175), which is the sum of the average Total Direct Cost of Gas, $0.3408 per therm (Line 168) and the average Indirect Cost of Gas, $0.0262 per therm (Line 172).

Also shown on the Summary Schedule are the proposed residential COG Factors for the 2018 / 2019 Winter Period (Line 68) and the 2017 Summer Period (Line 177), the proposed C&I Low Winter Use COG Factors for the 2018 / 2019 Winter Period (Line 72) and 2019 Summer Period (Line 181), and the proposed C&I High Winter Use COG Factors the Winter 2018 / 2019 Winter Period (Line 92) and 2019 Summer Period (Line 201).

1. 2018 / 2019 Winter Season COG

Q. What are the major components of the 2018 / 2019 Winter Season Anticipated Direct Cost of Gas?

A. The table below identifies the major components of Anticipated Direct Gas Costs, as shown on page 1 in the Summary Schedule.

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$1,683,109	3

2	Purchased Gas Supply Costs	$4,439,439	4
3	Storage and Peaking Capacity Costs	$13,190,356	7
4	Storage and Peaking Commodity Costs	$10,942,865	8
5	Inventory Financing	$3,017	10
6	Capacity Release and AMA revenue	($3,126,083)	12
7	Re-entry Rate & Conversion Rate Rev	($10,000)	14
8	Total Anticipated Direct Cost of gas	$27,122,704	16

Q. What are the major components of the 2018 / 2019 Winter Season Anticipated Indirect Cost of Gas?

A. The table below identifies the major components of Anticipated Indirect Gas Costs, as shown on page 1 in the Summary Schedule.

			Summary Schedule, Line:
1	Prior Period (Over) / Under-collection	$551,842	20
2	Interest	$(23,538)	21
3	Working Capital Allowance	$82,323	33
4	Bad Debt Allowance	$161,730	38
5	Local Production and Storage	$476,106	40
6	Miscellaneous Overhead	$471,052	42
7	Total Anticipated Indirect Cost of Gas	$1,719,515	44

Q. Please explain the calculation of the Working Capital allowances for the 2018 / 2019 Winter Season COG.

The total Working Capital allowance, $82,323 shown on Line 33 of the Summary Schedule is the sum of the current period working capital allowance, $74,383 (Line 29), plus the prior seasonal allocations of Working Capital reconciliation balance, $7,940 (Line 31).

Q. Please explain the calculation of the Bad Debt factors for 2018 / 2019 Winter COG.

A. The Bad Debt allowance, $161,730 (Line 38), is the sum of the current period bad debt allowances, $177,230 (Line 36), plus the seasonal allocations of the Bad Debt reconciliation balance, (15,500) (Line 37).

2. 2019 Summer Season COG

Q. What are the major components of the 2019 Summer Season Anticipated Direct Cost of Gas?

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

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$386,679	112
2	Purchased Gas Supply Costs	$1,973,217	113
3	Storage & Peaking Capacity Costs	$369,400	116
4	Storage & Peaking Commodity Costs	$31,552	117
5	Total Anticipated Direct Cost of gas	$2,760,847	125

Q. What are the major components of the 2019 Summer Season Anticipated Indirect Cost of Gas?

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

			Summary Schedule, Line:
1	Prior Period (Over) / Under-collection	$128,167	129
2	Interest	$(42,173)	130
3	Working Capital Allowance	$9,416	141
4	Bad Debt Allowance	$7,817	146
5	Miscellaneous Overhead	$109,403	150
6	Total Anticipated Indirect Cost of Gas	$212,629	152

Q. Please explain the calculation of the 2019 Summer Season Working Capital allowances.

The total Working Capital allowance, $9,416, as shown on Line 141 of the Summary Schedule is the sum of the current period working capital allowance, $7,572 (Line 138), plus the prior seasonal allocations of Working Capital reconciliation balance, $1,844 (Line 139).

Q. Please explain the calculation of the 2019 Summer Season Bad Debt factors.

A. The Bad Debt allowance, $7,817 (Line 146), is the sum of the current period bad debt allowances, $11,416 (Line 144), plus the seasonal allocations of the Bad Debt reconciliation balance, ($3,600) (Line 145).

I. <u>Summary Analyses</u>

Q. How does the proposed average 2018 / 2019 Winter Season COG rate compare to the average 2017 / 2018 Winter Season COG?

A. Schedule 9 compares the proposed 2018 / 2019 Winter Season average COG to the actual 2017 / 2018 Winter Season COGs rates. As this Schedule indicates, the Winter Season 2017 / 2018 COG was adjusted mid-season in order to minimize variances between target and projected end of season variance. Schedule 9 also shows that the proposed 2018 / 2019 Winter Season COG rate, $0.8271 per therm, is about $0.0395 per therm higher than the average 2017 / 2018 Winter Season COG. This $0.0395 per therm increase is primarily due to a higher demand costs due to the termination of the Portland Natural Gas Transportation System refund, a reconciliation under-collection compared to an over-collection in the prior year's reconciliation, and an over-all increase in demand costs as discussed in Mr. Well's testimony. This increase in demand costs is partially offset by an increase in forecasted demand and a decrease in projected commodity costs.

Q. How does the proposed 2019 Summer Season COG rate compare to the filed 2018 Summer Season COG rate?

A. Schedule 9 also compares the proposed 2019 Summer Season average COG to the filed 2018 Summer Season COG[17]. As this Schedule indicates, the proposed 2019 Summer Season average COG rate, $0.3670 per therm, is $0.0305 per therm lower than the 2018 Summer Season Average COG, $0.3795 per therm. This $0.0305 per therm decrease is primarily due to the allocation of a smaller share total demand costs to the summer period compared to the prior year, lower NYMEX prices, and higher forecasted sales.

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[17] To date, the 2018 Summer COG has not required any adjustments due to variances between target and projected end of year balances.

III. ANCILLARY CHARGES

Q. What ancillary charges and schedules have you updated for this filing?

A. I have provided updates to four ancillary charges / schedules. First, I have updated the Supplier Balancing Charge to be effective November 1, 2018. The proposed charge is $0.71 per MMBtu. I have prepared Schedule 18 to support the updated Supplier Balancing Charge calculation. The Company has simplified the formula to better reflect the pricing of the Union storage contract that replaced the Washington 10 storage contract on April 1, 2018 and the balancing service provided to marketers.

Second, I have updated the On-system Peaking Demand charge to be effective November 1, 2018 through April 30, 2018. The proposed charge is $50.35 per Dth. Support for this charge is provided by Mr. Wells in Schedule 5B. Both the Supplier Balancing Charge and On-system Peaking Demand Charge are included in Tariff Page No. 141, Appendix A.

Third, I have updated Tariff Page 156 which updates for capacity allocation percentages for all non-exempt Delivery Service customers for the period November 1, 2018 through October 31, 2018.

Lastly, I have updated the Re-entry Rates and Conversion Rates to be effective November 2018 through April 2019, and May 2019 through October 2019. In both the Winter Season and Summer Season, the proposed Re-entry Rates are $0.000 for both high and low load factor customers. In the Winter Season, the proposed Conversion Rate is $0.1211 for high load factor customers and $0.0041 for low load factor customers. In the Summer Season, the Conversion Rate is $0.0000 for both high and low load factor customers. These rates appear on Tariff Page No. 158, Appendix D. Support for these rates is provided by Mr. Wells in Schedule 20.

Q. Are you providing any additional information for Re-entry Rates and Conversion Rates?

A. Yes. Previously, when Northern utilized the Sales Service Re-entry Fee, the Company submitted a separate annual filing that provided the calculation of the Re-entry Fee along with Re-entry revenues from the prior year. In place of that filing, the calculation of the Re-entry Rate and Conversion Rate is provided in Schedule 20 and the associated revenues from the prior year are provided in Schedule 7.

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

A. Yes, Schedules 3, 23 and 24 have not been discussed in my testimony. Schedule 3 determines Northern's projected monthly over/under-collections, balances, and interest calculations. Schedule 23 provides additional supporting detail to the calculation of the COG rates. Lastly, Schedule 24 determines Northern's short-term debt limit calculation for the period November 2018 through October 2019.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2018 / 2019 Winter Season COG if it receives any new or updated information on gas supplier or transportation rates?

A. If requested by Commission Staff, the Company will file a revised calculation of its 2018 / 2019 Winter and Summer Season COGs to reflect updated gas and pipeline transportation cost projections as well as any other cost information a few weeks prior to the effective date of November 1, 2018. In addition, the Company will file proposed changes to the approved 2018 / 2019 Winter Season COG when the projected end of season variance exceeds 2% of the target projected cost of gas. As mentioned above, Schedule 3 projects Northern's monthly over/under collections, balances and interest. Northern will update this schedule each month with actual costs and updated NYMEX prices in order to determine the variance between the latest projected end of season balances and the target end of season balances established in the COG filing. As indicated on Line 89 on that schedule, Northern projects an over collection target balance of $3,434,918 on April 30, 2019. If, during the upcoming Winter Season, the Company's updated projected April 30, 2019 ending balance varies from the target balance by 2% or more of total target projected gas costs, then the Company will file to adjust the 2018 / 2019 Winter Season COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2018 / 2019 Winter Season COG.

Lastly, the Company will also file proposed changes to the approved 2019 Summer Season COG when the projected annual variance exceeds 4% of the target projected gas costs. As indicated on Schedule 3, Line 89, Northern projects an under-collection of $4,925 on October 31, 2019, the end of the Annual COG period. If, during the upcoming Summer Season, the Company's updated projected October 31, 2019 ending balance varies from the target Annual COG period balance by 4% or more of total targeted projected gas costs, and a rate change will help to lower the annual reconciliation balance, it will then file to change the 2019 Summer COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2019 Summer Period COG.

Q. Does this conclude your testimony?

A. Yes it does.